Utility 2.0 Long Range Plan & Energy Efficiency Plan

2024 Annual Update

Version 2

Prepared for Long Island Power Authority

July 1, 2024

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PSEG LONG ISLAND

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PSEG Long Island (the Utility) is submitting this Utility 2.0 Long Range Plan (Utility 2.0 Plan) and Energy Efficiency 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 to the Second Amended & Restated Operations Services Agreement on December 15, 2021 (herein after referred to as the Second A&R OSA).

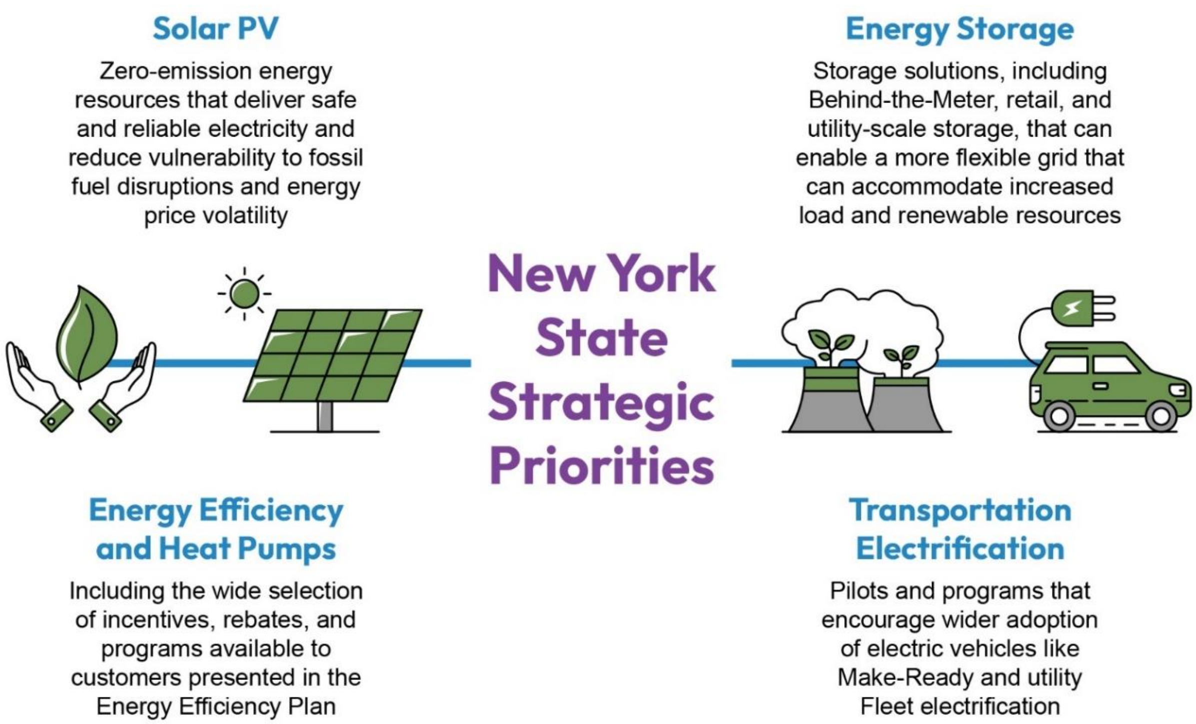
This Utility 2.0 Plan provides updates on six active Utility 2.0 initiatives previously reviewed by the DPS and approved by the LIPA Board of Trustees. PSEG Long Island seeks a positive recommendation on the 2024 Utility 2.0 Plan from the DPS and 2025 funding approval for previously approved and currently active Utility 2.0 programs.

This Utility 2.0 Plan also includes an update to PSEG Long Island's Energy Efficiency (EE) Plan (included as **Chapter 2**). PSEG Long Island's EE programs make a wide selection of incentives, rebates, and programs available to residential and commercial customers on Long Island and the Rockaways 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 EE Plan.

PSEG Long Island's Utility 2.0 Vision

New York State and Long Island are committed to leading the country in transforming the energy system, decarbonizing our economy, and supporting disadvantaged communities (DACs), which are priorities identified in the New York State Climate Leadership and Community Protection Act (Climate Act or CLCPA). PSEG Long Island presented an updated Utility 2.0 vision and framework in the 2023 Utility 2.0 Plan. This year's Utility 2.0 Plan is even more closely aligned with New York State's five strategic priority areas with chapters dedicated to each priority area. **Figure ES-1** details New York State's five strategic priority areas. Note that Energy Efficiency and Heat Pumps are combined in the structure of this year's Plan due to the dependencies across these priority areas.

Figure ES-1. New York State 2025 Strategic Priorities and PSEG Long Island's Utility 2.0 & EE Plan

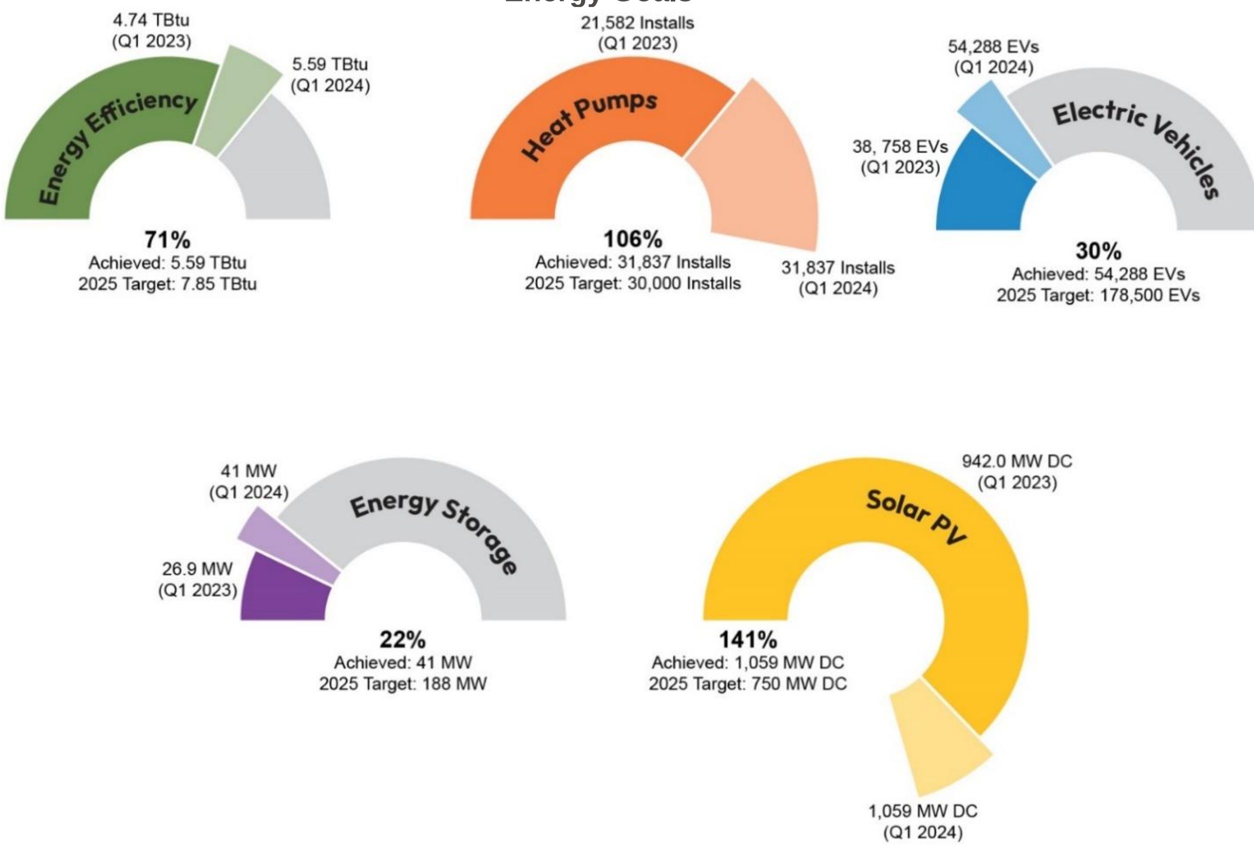


Long Island Supports the Achievement of Statewide Clean Energy Goals

Active Utility 2.0 initiatives directly contribute to achieving goals across New York State's strategic priorities. 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 EE Plan (**Chapter 2**). 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 (**Section 1.3.2**).

PSEG Long Island's progress towards Long Island's portion of the State's Clean Energy Goals as of Q1 2024 is presented in **Figure ES-2**.

Figure ES-2. Progress[1] towards Long Island's Portion of New York State's 2025 Clean Energy Goals[2]



[1] EE Savings reflects savings since 2019. Heat pump installations reflect installations since 2020.The Solar PV Goal for 2025 has been accomplished.
[2] Current as of Q1 2024 based on data availability.

PSEG Long Island's Utility 2.0 Plan and EE Plan

2024 Utility 2.0 Plan

PSEG Long Island's 2024 Utility 2.0 Plan showcases a review of Utility 2.0 accomplishments in 2024 thus far and a one-year outlook on six previously approved programs and a request for one scope addition, within the Make-Ready program.

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 Second A&R OSA and the LIPA Performance Metrics documents and provided through additional guidance from LIPA via the Utility 2.0 Plan annual filing process and,
- **Similar projects across the Joint Utilities (JU)**[3] as identified through coordinated communication and planning.

2025 Energy Efficiency (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 EE Plan is included as **Chapter 2** of this document, representing PSEG Long Island's initiatives that contribute to its share of New York State's Energy Efficiency and Heat Pump goals.

Utility 2.0 Plan and EE Plan Funding Requests

The Utility 2.0 Plan and EE Plan are presented separately with **Chapter 2** representing the EE Plan and **Chapters 3 through 7** representing the Utility 2.0 Plan. Historically, the EE Plan has been provided as an Appendix to the annual Utility 2.0 Plan. In this year's Utility 2.0 Plan, it is provided in the main body of the report because PSEG Long Island is realigning the overall Utility 2.0 Plan to be structured by the New York State CLCPA goals (Energy Efficiency, Heat Pumps, Transportation Electrification, Energy Storage, and Solar Photovoltaics (PV)), including developing Five-Year Plans for each priority area.

[3] Participant utilities of the JU include 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. See jointutilitiesofny.org for more information on the JU.

However, it is important to note that the programs presented in the EE Plan are funded through budgets separate from the Utility 2.0 program. As a result, funding request and budget allocation for the Utility 2.0 Plan and the EE Plan will be presented separately throughout this document.

PSEG Long Island requests a total Utility 2.0 budget of $27.60 million ($13.24 million in capital and $14.36 million in operations and maintenance (O&M)) for active initiatives, including initiatives with requested scope expansions, in 2025. PSEG Long Island also requests a total Energy Efficiency Plan budget of $93.7 million.

The funding request values presented throughout this document are subject to change, pending the result of ongoing discussions with LIPA on the proposed 2025 O&M budgets. The proposed funding request presented in **Table ES-1** below and throughout **Chapters 2, 3, 4**, and **7** represents the funding required to grow PSEG Long Island's Utility 2.0 portfolio in a manner that aligns with the priorities of New York State—in particular, growing participation in EE and EV programs to support the State's goal of 40% greenhouse gas (GHG) reductions by 2030 across all sectors.[4]

Full details on projects costs and variances by year can be found in **Chapter 7** with project-specific details in the sections identified in **Table ES-1** below. It is important to note that budgetary values presented in the table below are rounded to the hundredths decimal place.

Table ES-1. 2025 Total Active Program Funding Request

Initiative	Document Section	Capital 2025 ($M)	O&M 2025 ($M)	Total 2025 ($M)
Make-Ready Programs	**3.2.1**	**7.83**[5]	**10.34**	**18.17**
EV Make-Ready Program		*6.27*	*9.28*	*15.55*
Fleet Make-Ready Program		*1.56*	*1.06*	*2.62*
Electric Vehicle Programs	**3.2.2**	**2.01**[5]	**2.82**[6]	**4.83**
Demand Charge Rebate		*-*	*1.00*	*1.00*
EV Phase-In Rate		*2.01*	*0.19*	*2.20*
Residential Charger Rebate Program		*-*	*1.38*	*1.38*

[4] New York State Climate Action Council. Scoping Plan – Full Report December 2022.
[5] A portion of the Capital Forecasts for 2025 are attributed to Capital Expenditure for Utility 2.0 PMO Support on the Make-Ready Programs, EV Programs, and the IEDR Platform.
[6] Marketing and Outreach for the Electric Vehicle Programs is all encompassing. So, the Marketing and Outreach is included in the Overall O&M Total for the Electric Vehicle Program, but it is not allocated to a specific sub-project within the Electric Vehicle Program. Thus, the Electric Vehicle Programs O&M Totals do not equal the sum of the sub-project O&M Totals.

Initiative	Document Section	Capital 2025 ($M)	O&M 2025 ($M)	Total 2025 ($M)
Suffolk County Bus Make-Ready	**3.2.3**	**-**	**0.31**	**0.31**
Connected Buildings Pilot	**4.2.1**	**-**	**0.04**	**0.04**
Residential Energy Storage Program	**4.2.2**	**-**	**0.65**	**0.65**
IEDR Platform	**6.1**	**3.40**[5]	**0.20**	**3.60**
	Total Utility 2.0 Programs	**13.24**	**14.36**	**27.60**
	Total EE Programs	**-**	**93.7**	**93.7**
	Total Utility 2.0 and EE	**13.24**	**108.06**	**121.30**

PSEG Long Island's EE Plan 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 (DLM) offerings as well as some remaining supplemental 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 2025 EE Plan

Program	Sector	Savings (MMBtu)	Savings (MWh)	Program Budget ($M)
Energy Efficient Products	Residential	155,564	8,887	8.11
Home Comfort	Residential	182,387	3,570	26.96
Residential Energy Affordability Partnership (Low-Income)	Residential	13,588	1,201	3.37
Home Performance	Residential	39,595	2,418	10.93
Multifamily	Commercial	64,882	5,108	6.60
All Electric Homes	Residential	--	--	0
Commercial Efficiency	Commercial	185,171	49,896	23.59
Home Energy Management	Residential	133,000	38,980	2.19
Total, Budget Components with Programmatic Savings		**774,188**	**110,059**	**81.73**
Dynamic Load Management (DLM) Program		-	-	2.26
PSEG Long Island Labor		-	-	3.53

Program	Sector	Savings (MMBtu)	Savings (MWh)	Program Budget ($M)
Outside Services		-	-	2.43
Advertising		-	-	2.60
G&A		-	-	0.90
Community Solar		-	-	0.25
Total, Budget Components Not Associated with Programmatic Savings		**-**	**-**	**11.98**
Total EE Funding Request		**774,188**	**110,059**	**93.71**

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

Table ES-3. 2025 Income-Eligible Customer Goals in the EE Plan

Program	Savings (MMBtu)	Participation (Units)	Rebates & Incentives Budget ($M)
Home Comfort – LMI	58,084	2,669	9.48
REAP	13,588	18,185	3.37
Home Performance - LMI	17,813	1,052	5.96
Marketing & Outreach	-	-	1.20
Total	**89,485**	**21,906**	**20.01**

PSEG Long Island's EE Plan identifies opportunities to advance energy affordability for LMI customers 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 $20.01 million in spending in 2025.

Five-Year Plans

PSEG Long Island has developed Five-Year Plans for each of the New York State priority areas: Energy Efficiency, Heat Pumps, Transportation Electrification, Energy Storage, and Solar PV. Each Five-Year Plan presents PSEG Long Island's current outlook within each priority area for the period of 2026 through 2030, detailing milestones of achievement and growth within Utility 2.0 programs as applicable.

The Five-Year Plans provide insight on the Utility's expected achievement of its share of the state's 2030 climate goals and the programs or initiatives that will contribute towards that achievement. While these Plans represent PSEG Long Island's current thinking, specific targets and budgets to implement future programs are subject to change given the evolution of state priorities, market conditions, technology advancements and customer adoption. Energy Efficiency does not have a specific 2030 goal as defined by the State. As a result, the Energy Efficiency Five-Year Plan details the expected growth of PSEG Long Island's Energy Efficiency portfolio through 2030, reflecting associated savings in pursuit of the 2030 heat pump dwellings goal and available energy efficiency savings measures. Should a statewide Energy Efficiency target be determined in the future, the Utility will reassess its Five-Year Plan and adjust as necessary to align with state goals.

Table ES-4 below provides and overview for planned initiatives and activities within the Five-Year Plans. See **Section 2.4** for the Energy Efficiency and Heat Pumps Plan, **Section 3.3** for the Transportation Electrification Plan, **Section 4.3** for the Energy Storage Plan, and **Section 5.2** for the Solar PV Plan.

Table ES-4. Utility 2.0 and EE Planned Initiatives (2025-2030)

Priority Area	Document Section	Initiatives	Estimated Utility 2.0/EE Program Funding Required ($M)
Energy Efficiency	**2.4**	• Commercial Weatherization • Multifamily Heat Pumps • Commercial Other (Ref, HVAC Controls, Cooking) • Residential Weatherization • Residential Heat Pumps Water Heaters (HPWH) • Residential Heat Pumps (excluding HPWH) • Residential Controls + Other	~801
Heat Pumps	**2.4**	• Multifamily Heat Pumps • Residential Heat Pumps • Codes and Standards	
Transportation Electrification	**3.3**	• Make-Ready Program • EV Program • Managed Charging Program	~230
Energy Storage	**4.3**	• Behind-the-meter (BTM) ○ Utility 2.0 Residential Energy Storage System Incentive Program	~2

Priority Area	Document Section	Initiatives	Estimated Utility 2.0/EE Program Funding Required ($M)
Energy Storage	**4.3**	*Outside of Utility 2.0/EE Plan. See text for details:* • Retail Energy Storage Pilot Program • Front-of-the-Meter (FTM): ○ East Hampton & Montauk • Bulk Energy Storage System (BESS)	N/A
Solar PV	**5.2**	• *Outside of Utility 2.0/EE Plan. See text for details.*	N/A

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.[7]

The reporting of updates to approved initiatives and the proposal for expanded scope within one previously approved initiative are included in **Chapters 2 through 6**. Key figures across the Utility 2.0 portfolio, such as quantifiable benefits and spend, are summarized in **Chapter 1**.

Overall, the 2024 Utility 2.0 Plan 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 Plan 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 2025 and progress updates, performance reporting, and budget reconciliation for approved initiatives that are in active in 2025 for the five New York State Priority Areas.

[7] 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 2 through 6.

- **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.
- **Appendix A** contains PSEG Long Island's BCA Handbook.
- **Appendix B** provides a list of the operationalized and completed Utility 2.0 initiatives.
- **Appendix C** provides a summary of the way LIPA and PSEG Long Island are organized.
- **Appendix D** includes a listing of acronyms and abbreviations used in this document.

1. Introduction

2024 Utility 2.0 Plan Annual Filing, Energy Efficiency Plan, and Five-Year Plans

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 Second A&R OSA.

1. Introduction

1.1. PSEG Long Island's Utility 2.0 Vision

The global energy industry is actively undergoing critical transformation that will impact customers and energy distribution systems. New York State and Long Island continue to stay committed to prioritizing goals and projects that support and are responsive to the dynamic changes taking place in the energy industry. July 2024 marks five years since New York State's Climate Leadership and Community Protection Act (Climate Act or CLCPA), one of the most ambitious climate laws in the world, was signed into law.

As the State evaluates progress to date towards achieving CLCPA goals 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. This year's Utility 2.0 Plan is structured to directly align with New York State priorities as detailed in the CLCPA, with Chapters dedicated to five statewide priority areas: Energy Efficiency & Heat Pumps (**Chapter 2**), Transportation Electrification (**Chapter 3**), Energy Storage (**Chapter 4**), and Solar PV (**Chapter 5**). Historically, the EE Plan has been provided as an Appendix to the annual Utility 2.0 Plan, but in accordance with this realignment towards priorities of the CLCPA the EE Plan has been moved to the main body of the document as **Chapter 2** which details PSEG Long Island's targets and programs related to Energy Efficiency and Heat Pumps.

In addition, PSEG Long Island has updated the Utility 2.0 Vision to reflect more closely its commitment to supporting statewide climate goals (**Figure 1-1**).

Figure 1-1. PSEG Long Island's Utility 2.0 Vision (Updated 2024)

PSEG Long Island's Utility 2.0 vision is to **support statewide climate goals,** as detailed in New York State's Climate Leadership and Community Protection Act, while **responding to the evolving needs of its customers**. PSEG Long Island will achieve this vision by developing and operating programs that directly support New York State climate goals in Energy Efficiency, Heat Pumps, Transportation Electrification, Energy Storage, and Solar PV.

PSEG Long Island, in coordination with the DPS and LIPA, continuously seeks ways to evolve its solutions and services to support its customers and their needs. Over the years, many of the projects and initiatives borne out of the Utility 2.0 program transitioned into PSEG Long Island's core operations. Projects that transitioned to Operational status in 2024 are detailed in **Appendix B**. The successful integration of projects into PSEG Long Island's core operational activities makes way for the next evolution of Utility 2.0.

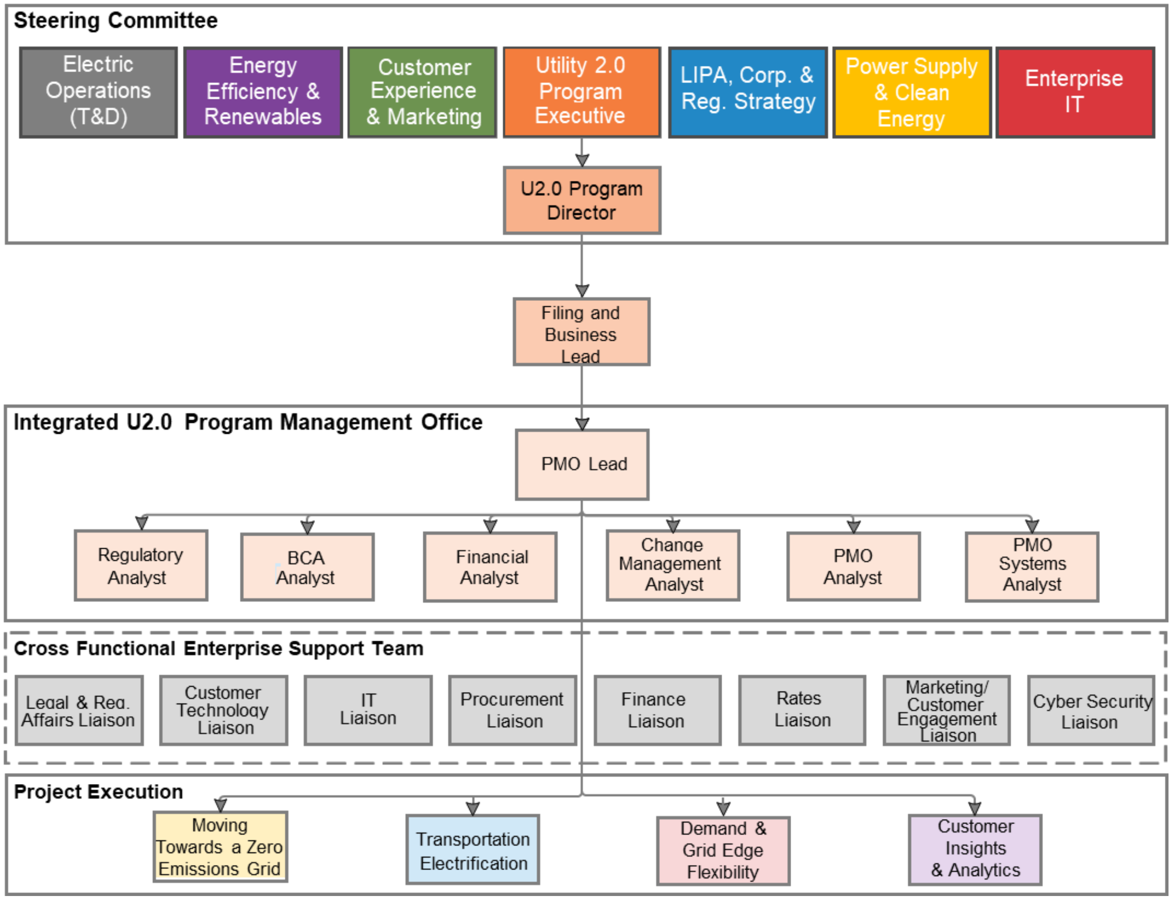
1.2. Managing the Utility 2.0 Program and Annual Filing Process

PSEG Long Island's Utility 2.0 vision is realized through an enterprise-wide program that currently includes six active initiatives with a projected spend of approximately $20.66 million in 2024. These initiatives span multiple functional groups with considerable departmental interdependencies and regulatory oversight. These initiatives also 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. The Utility 2.0 PMO develops the Utility 2.0 Plan 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 conducting associated meetings with stakeholders including the DPS, LIPA, NYSERDA 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 projects and initiatives as well as to enable the exchange of information across customer service, transmission and distribution (T&D), information technology (IT), and other key stakeholders (**Figure 1-2**).

Figure 1-2. Utility 2.0 Governance Structure[8]



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 1-3**.

[8] 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.

Figure 1-3. Annual Utility 2.0 Plan Filing Stage Gate Process

STAGE GATE 1:

- Ideation and identification of new initiative(s) to propose based on state policies, gaps, and customer needs

STAGE GATE 2:

- Preparation of draft funding requests (Capital and O&M) for new initiative(s)
- Refined program design
- Small group working sessions with the DPS, LIPA, and external stakeholders to get feedback on the proposed initiative(s)
- Ongoing development of the EE Plan

STAGE GATE 3:

- Development of a Benefit Cost Analysis (BCA) or cost justification for some new initiatives
- Small group working sessions with the DPS, LIPA, and external stakeholders to continue receiving ongoing feedback on any proposed U2.0 initiative(s)
- If the new initiative is a Pilot, various hypotheses will be developed to test the success
- Ongoing development of the EE Plan

STAGE GATE 4:

- Feedback session with the DPS and LIPA on drafted filing document
- Refinement of BCA or cost justification for some new initiatives
- Finalization of Utility 2.0 Filing and EE Plan based on regulator feedback and finalized budgets

Once an initiative or scope expansion is approved through Stage Gate 4, 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 and EE Plan are submitted on July 1st, the 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 issued by the 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 or program expansion.

1.3. Long Island Supports the Achievement of Statewide Clean Energy Goals

The New York State Climate Action Council developed a Scoping Plan[9] to serve as a framework for how the State will reduce 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.

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, as detailed in **Chapter 2.** Long Island’s share of the statewide goals is based on the assumptions listed in **Table 1-1.**

[9] New York State Climate Action Council. Scoping Plan – Full Report December 2022.

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)
Energy Efficiency	7.85 TBtu Savings	TBD[10]	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.[11]
Heat Pumps	30,000 Installs	67,769 dwellings[12]	The basis for the 2025 goal was the 2020 annual EEDR Plan for that year's heat pump categories, with a reasonable growth rate across categories. The 2030 goal of number of dwellings is based on the outputs of the NYSERDA's Building Efficiency and Electrification Model (BEEM).
Electric Vehicles	178,500 EVs[13]	100% of LDV sales are ZEVs *(by 2035)*[14]	Based on Long Island's share of vehicle registrations in New York (approximately 21%)
Energy Storage	188 MW[15]	TBD	Statewide Goal for energy storage is 6,000 MW by 2030
Solar PV	750 MW DC	1,300 MW DC	Based on Long Island's share of statewide peak load (approximately 12.5%)

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 Energy Efficiency, Heat Pumps, Transportation Electrification,

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[10] The statewide goals for 2030 for EE are still to be determined by New York State.
[11] Order Adopting Accelerated EE Targets, CASE 18-M-0084 In the Matter of a Comprehensive EE Initiative, December 13, 2018.
[12] The 2030 CLCPA statewide target for heat pump is 1,000,000 housing units. According to the NSYERDA BEEM, Long Island's portion of the 2030 goal is estimated to be 67,769 dwellings, as reflected in detail in **Section 2.4**
[13] Value reflects Long Island's share of the overall New York State goal of 850,000 light duty vehicles registered and on the road by the end of 2025 rather than an official goal for EV adoption on Long Island.
[14] The 2030 statewide goal is yet to be determined. The 2035 goal is based on Advanced Clean Cars II and reflects only EV sales.
[15] Values reflect targets rather than official goals for Long Island's portion of the 2025 and 2030 Energy Storage CLCPA target.

Energy Storage, and Solar PV are detailed in **Table 1-2**, in addition to Long Island's share of New York State clean energy goals. 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	Electric Vehicles	Energy Storage	Solar PV
Statewide Goal for 2025	185 TBtu	5 TBtu	850,000[16]	1,500 MW	6,000 MW DC
Long Island Portion of 2025 Goals	7.85 TBtu	30,000 installations	178,500[17]	188 MW	750 MW DC
Actuals on Long Island (Q1 2024)	~5.59 TBtu	~31,837 installations	~54,288	~41 MW	~1,059 MW DC
Statewide Goal for 2030	TBD	1,000,000 dwellings[18]	TBD	6,000 MW[19]	10,000 MW DC[20]
Long Island Portion of 2030 Goals	TBD	67,769 dwellings	TBD	TBD MW[21]	1,300 MW DC
Active & Approved Initiatives	• EE Programs (EE Plan)	• EE Programs (EE Plan)	• EV Programs • Make-Ready Programs • Suffolk County Make-Ready Pilot	• Energy Storage Bulk Solicitation • Connected Buildings Pilot • Residential Energy Storage System Incentive	• Connected Buildings Pilot

Orange Text: Prospective Benefits for DACs. DACs and goals are tracked per Disadvantaged Communities Investments and Benefits Reporting Guidance for New York State Entities.

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[16] This statewide goal is now superseded by ACC and ACT, both of which focus on vehicle sales.
[17] Value reflects Long Island's share of the overall New York State goal of 850,000 light duty vehicles registered and on the road by the end of 2025 rather than an official goal for EV adoption on Long Island.
[18] Metric for the statewide Heat Pump target shifts from installations to dwellings to more accurately represent Governor Hochul's 2 million electrified or electrification-ready homes plan by 2030.
[19] Governor Hochul's 2022 State of the State Book [governor.ny.gov] (page 146)
[20] Governor Hochul Announces Expanded NY-Sun Program to Achieve at Least 10 Gigawatts of Solar Energy by 2030
[21] This value is reflected as 'TBD' because PSEG Long Island achieving the load-share-ratio of 750 MW of Energy Storage on Long Island by the end of 2030 is dependent on the level of energy storage procured by the state and what share is contracted to PSEG Long Island. Thus, PSEG Long Island is committed to contributing to the overall 2030 statewide energy storage CLCPA goal, but the achievement of this goal is reliant on the progress of the state.

1.3.2. Achievement of Statewide Goals Outside 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. In coordination with active and planned Utility 2.0 initiatives, PSEG Long Island engages in transportation electrification efforts external to Utility 2.0, including the investigation of purchasing an electric bucket truck to inform future programs aimed at electrifying the broader population of Medium- and Heavy-Duty Vehicles (MHDVs). Additionally, the Utility's Time of Day (TOD) Rates is an effort outside of Utility 2.0 that advances statewide climate goals.

Fleet 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 currently has 40 hybrid electric bucket trucks on order with expected deliveries starting in Q4 of 2025. In the coming years, PSEG Long Island plans to issue an RFP to procure additional bucket trucks and LDVs based on the replacement cycle and suitability.
- **Existing Vehicles**: PSEG Long Island's existing fleet of vehicles have 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 conditions and operations to identify those vehicles that are ready and suitable for electrification.
- **Suitability**: PSEG Long Island is planning to electrify its LDV fleet, with the intention that as range, cost and other factors improve, PSEG Long Island will plan to electrify its MDHV fleet in later years. PSEG Long Island recommends that a business should transition its fleet to electric, while meeting its operational needs.
- **Charging Infrastructure Planning**: PSEG Long Island has continued discussions with National Grid, who owns the yards that PSEG Long Island rents from, to identify the type of charging equipment needed and where the charging stations would be located. Currently, charging equipment and grid infrastructure are being installed and upgraded at Brentwood, Roslyn, and Hewlett. A new PSEG Long Island location in Medford is being designed to support a full location EV plan. In the coming years, PSEG Long Island will continue to evaluate its plan to support electrification of all

LDVs by the end of 2029 which is in line with the New York State Executive Order 22.[22]

PSEG Long Island's Fleet Transportation group is following the LIPA recommendations from a recent fleet assessment. In the coming months, the group plans to identify those vehicle classes that will be ready to electrify and to develop strategies to electrify each vehicle class. The group expects that most LDVs will be electrified first with MHDVs being electrified in later years.

Fleet Electrification Study[23]

To further support fleet electrification and understand its impacts, PSEG Long Island plans to coordinate with LIPA on a Fleet Electrification Study to develop a detailed analysis of light-duty (LD), medium-, and heavy-duty (MHD) fleets located within PSEG Long Island's service territory. The Fleet Electrification Study will identify detailed fleet information such as fleet depot locations, and number of vehicles by class (1 to 8). The Study will also develop a granular forecast of commercial fleet EV adoption, charging infrastructure needs and associated load impacts at feeder level. The results will inform the development of proactive grid planning to ensure that grid infrastructure is prepared for growing EV charging needs from fleet electrification on Long Island.

Phase 1

The first task of the Study is to identify fleets by collecting and analyzing detailed information on LD and MHD fleet vehicles within PSEG Long Island's service territory. This information includes the name of fleet owners, location of fleet depots, fleet size, vehicle types, fuel type, intentions to electrify their vehicle fleet, and the industry each fleet operates in. The goal of this task is to develop a list of LD and MHD fleets located within PSEG Long Island's service territory (by feeder) with the associated fleet information. Data from the first task of the Study will be used to conduct a bottom-up forecast of EV fleet adoption, charging infrastructure needs, and associated load profiles, and grid impacts at a circuit level through 2050. The goal of this task is to forecast EV adoption rates by vehicle type and/or industry, charging needs and utilize the EV load forecast for further planning studies.

Phase 2

The Study will conclude with a grid impact assessment that will identify grid impact at a circuit level through a steady-state power flow analysis. The information will be used to determine the circuits/substations that will be impacted by fleet electrification. This Study will

[22] PSEG Long Island submitted the ZEV Conversion Plan to the DPS in December 2023.
[23] LIPA will complete Phase 1 of this study in H2 2024. PSEG Long Island will conduct Phase 2 internally.

provide PSEG Long Island with a detailed analysis of needed infrastructure upgrades based on fleet electrification forecasts.

The Utility of the Future (UoF) and Distribution Planning teams plan on working collaboratively to analyze each feeder on Long Island where the Utility sees fleet electrification would occur. The results of this analysis would help PSEG Long Island understand the overall impact that fleet electrification will have on its system. **Table 1-3** shows the estimated schedule for the Fleet Electrification Study.

Table 1-3. Fleet Electrification Study Estimated Schedule

Workstream	H2 2024	2025	2026+
Phase 1			
Task 1: Fleet Identification	■		
Task 2: Fleet Market Assessment	■		
Phase 2			
Task 3: Grid Impact Assessment		■	■

Phase 2 is contingent upon the number of feeders that need to be assessed based on the results of Task 2. Given the current resources, the highest loads will be assessed first and may result in a multi-year effort. Additionally, PSEG Long Island may continue this effort with annual updates to capture market trends.

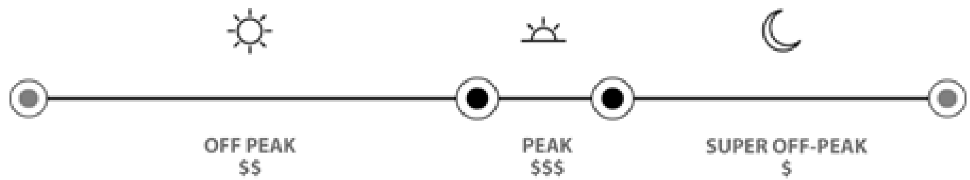
Time of Day (TOD) Rates

In March 2023, the LIPA Board of trustees voted to implement new residential TOD rates. As of November 2023, customers could voluntarily opt into the new TOD rates and in January 2024, the off-peak two-period rate became the standard rate for residential customers that start a new service. Residential customers currently on the flat rate will be transitioned to the new standard TOD rate in migration groups starting in June 2024 and this will continue through 2025 and beyond. 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 rates charge 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 to reduce carbon emissions on Long Island.

PSEG Long Island has two TOD rate options: both the standard 2-block period TOD "off-peak" rate and the optional 3-block period "super off-peak" rate. The super off-peak period offers additional incentives for customers 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 1-4** below.

Figure 1-4. Off-Peak, Peak, and Super Off-Peak Periods



To recognize the time it takes to learn how to shift household electric usage from peak to off-peak and reduce any risk to customers, PSEG Long Island is making bill protection available to flat rate residential customers that either opt-in, are migrated to TOD, or move-in and start service on the TOD rate. A customer who has a higher bill on TOD than they would have had on the flat rate will receive a bill credit for the difference. Customers will receive this bill credit either after they have spent 12 months on the TOD rate or after they opt out prior to 12 months on the rate. The public website has been updated with information on TOD specifics, including a video and rate comparison tool. Customers can view their personalized rate comparisons in their PSEG Long Island MyAccount or Mobile App. 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 began in March 2024 for the first group.

1.4. Delivering Benefits to Disadvantaged Communities (DACs)

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[24]. The CJWG used 45 indicators to develop the criteria for identifying DACs and found that 35% of New York State census tracts are designated 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

[24] New York State. Disadvantaged Communities Criteria.

allows investments for individual households, regardless of geographic location, making at or below 60% SMI to be included and counted toward the benefits to DACs.

In January 2024, the New York State Department of Environmental Conservation (DEC) and NYSERDA released draft statewide guidance for the investments and benefits reporting requirement. The draft guidance states that all New York State agencies, authorities, and entities must invest in a manner that allows them to achieve a goal for DACs to receive 40% of overall benefits of spending[25]. In addition, DACs shall receive no less than 35% of the overall statewide benefits of spending on clean energy and EE programs, projects, or investments.

PSEG Long Island is committed to developing programs, services, and other offerings to support Low to Moderate Income (LMI) customers including geographic DAC customers and any business/industrial customers who reside within DAC census tracts (in these cases the census tract of the business location is used).

In accordance with statewide guidance, PSEG Long Island defines low-income customers as participant households whose income is at or below 60% SMI. Moderate-income customers are defined as households whose income is at or below 80% SMI and moderate income customers do not count toward the DAC goals but are still supported through PSEG Long Island's programs. PSEG Long Island will continue to monitor and participate in Climate Act working groups while also submitting all necessary reporting data to NYSERDA that demonstrate commitment towards clean energy and energy efficiency DAC investments requirements.

PSEG Long Island has developed the capability to report on customer program participation by census tract, including the ability to flag participants residing in DACs based on the geographic location of the meter associated with customer account numbers. The Utility has been able to map 98% of accounts in its service territory to census tracts and will continue to improve the accuracy of geocoding all its 1.1 million customers.

Tracking customers by census tract combined with state defined DAC designation enables the Utility to market specific programs to these customers and to be compliant with reporting on investments made to support the clean energy transition in DACs. PSEG Long Island also has the ability to retrospectively report the impact that programs have had on DACs in the past which is also required for DAC reporting.

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[25] New York State. Investments and Benefits Reporting Guidance.

PSEG Long Island tracks geographic DAC spending for all of EE and Beneficial Electrification programs as well as low-income customer participation for any program that has low-income offerings, which includes Home Performance, Home Comfort, and REAP programs. Home Performance and Home Comfort low-income offerings are only available for customers who meet the 60% SMI criteria. The REAP program assists both moderate and low-income participants. As of 2023, PSEG Long Island has begun tracking REAP participants by income threshold which allows the Utility to bifurcate customers that qualify as low-income and moderate-income.

PSEG Long Island's EE Plan (**Chapter 2**) 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 $20.01 million in spending in 2025. The 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. Lastly, the Make-Ready Program and the EV Program both offer enhanced incentives for customers in DAC census tracts, as detailed in **Chapter 3**.

Lastly, the Regional Clean Energy Hubs Program run by NYSERDA further provides education and resources to LMI customers in Long Island. The Clean Energy Hubs are community-based organizations that provide information to customers interested in the benefits of the clean energy transition and in learning ways to reduce energy use and cost. PSEG Long Island will coordinate with the Long Island Clean Energy Hub to further the reach of its low-income programs and provide energy efficiency resources for customers in DACs.

1.5. Looking Ahead to the Future

PSEG Long Island's 2024 Utility 2.0 and EE Plan represents a one-year outlook and funding request. This year's Plan also includes a five-year outlook aligned to New York State CLPCA goals of Energy Efficiency, Heat Pumps, Transportation Electrification, Energy Storage, and Solar PV. These Five-Year Plans represent the Utility's present outlook on activities from 2026 to 2030 that support achievement of CLCPA goals, however many of the plans and studies listed within these Plans are not yet finalized or are still awaiting finalization. Anything presented beyond 2025 in this plan is subject to change based on evolution of future state policies, market conditions, technology advancements and customer adoption, and therefore are not included in the request for additional funds at the time of this filing.

2. Energy Efficiency and Heat Pumps

2024 Utility 2.0 Annual Plan Filing, Energy Efficiency Plan, and Five-Year Plans

PSEG Long Island (the Utility) 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 Second A&R OSA. PSEG Long Island seeks a positive recommendation on the Plan from DPS and funding approval from LIPA for 2025.

2. Energy Efficiency and Heat Pumps

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. Buildings contribute about a third of the state's total direct carbon emissions. Building Electrification and Energy Efficiency 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.

The Climate Act emphasizes the need for homes to follow this electrification trend through the implementation of heat pump and energy efficiency technologies. Statewide, over 200,000 homes per year must be upgraded to be highly efficient and fully electrified by 2030.[26] Additionally, 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[27] by 2030.[28] 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 residential and commercial savings programs for customers outside of Utility 2.0. Building decarbonization and envelope improvements are addressed by the programs in the EE Plan. The EE Plan 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.

New Efficiency: New York

As part of its overall goal of reducing GHG emissions by 40% by 2030 and driven by the CLCPA goals, New York set a new statewide EE target of 185 TBtu by 2025. In December of 2018, New Efficiency: New York (NE:NY)[29] established an incremental target of 31 TBtu of reduction by the State's utilities toward the achievement of the 2025 goal. Within that 31 TBtu goal, LIPA was assigned a proportional share of at least 3 TBtu in EE savings over the

[26] NYSERDA Carbon Neutral Buildings Roadmap: Achieving a carbon neutral building stock in New York State by 2050.
[27] Electrification-ready means a home or building is wired to accommodate the installation of future electric equipment (NEEP)
[28] 2022 New York State of the State Book
[29] New Efficiency: New York Order

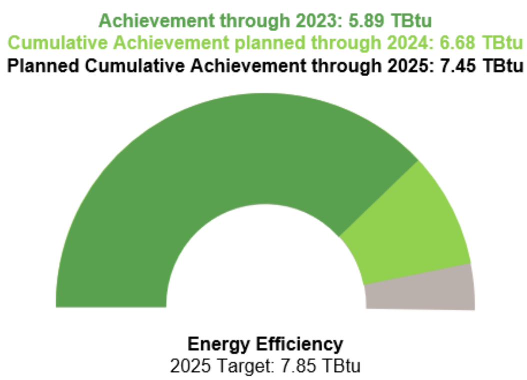
2019-2025 period, or 7.85 TBtu when combining base-level electric savings and the incremental amount established in the December 2018 Order. By laying out these targets, New York established fuel-neutral metrics to incorporate beneficial electrification in the building and transportation sectors, which is necessary to achieve the State's carbon reduction goals. In response, PSEG Long Island:

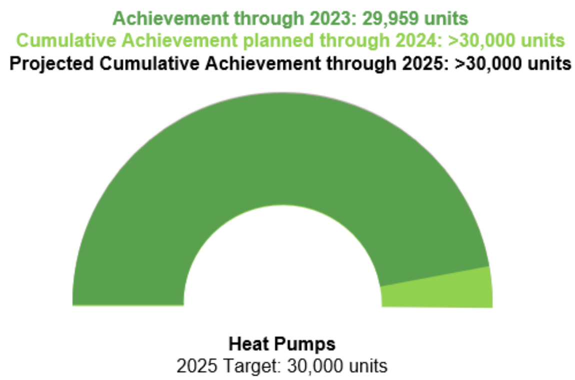
- **Adopted a 7.85 TBtu by 2025 target and changed its primary performance metric from electric energy (kWh) and peak demand (kW) to MMBtu:** Long Island became the first region in New York State to convert all electric savings to MMBtu to better conform with the NE:NY goals. This switch allows PSEG Long Island to pursue beneficial electrification measures like heat pumps that increase electric consumption but lower overall energy consumption and emissions. PSEG Long Island is responsible for reporting their progress towards the 2025 energy efficiency goal of 7.85 TBtu.
- **Addressed interactive effects between lighting upgrades and a home's HVAC System.** PSEG Long Island's initial and more conservative approach of applying heating penalties to lighting upgrades in homes with fossil fuel heat, was not in line with the way other New York State utilities were reporting lighting savings and had reported lower MMBtu savings. For consistency with the Investor Owned Utilities (IOUs), the impacts to be counted towards this target should be calculated excluding fossil fuel heating penalties. Starting in 2024, PSEG Long Island has revised its approach to calculate savings for lighting upgrades without heating penalties to be consistent with the rest of the electric utilities in New York State.
- **Incorporated and continues to expand beneficial electrification measures in its offerings.** PSEG Long Island has continued to pioneer efforts to expand their energy efficiency programs to include rebates and incentives for customers to install measures that supply beneficial electrification to the grid, such as heat pumps, and allow customers to save on their fossil fuel-based costs. 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 in turn shifts investment towards more non-lighting opportunities, i.e., heat pumps and other beneficial electrification opportunities. Shifting rebate and incentive opportunities to a fuel-neutral basis de-emphasizes electric (kWh) savings 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 more effectively rather than electric consumption or demand savings, which served as prior metrics.

2.1. 2025 Goal Achievement

The 2025 energy efficiency goal tracks two key milestones: Achieve overall 7.85 TBtu in energy savings along with 30,000 heat pump installations[30] on Long Island. PSEG Long Island has already achieved its 2025 goal of 30,000 heat pump installations as of Q1 2024. As of Q4 2023, PSEG Long Island has achieved 69% of the 2025 energy efficiency goal of 7.85 TBtu. Assuming achievement of the authorized 2024 EE/BE plan and 2025 EE/BE plan set forth herein, PSEG Long Island expects to achieve 95% of the 2025 energy efficiency goal at the end of 2025 and that the achievement of the full 7.85 TBtu will likely occur during the first half of 2026. **Figure 2-1** below depicts the actual progress for heat pump installs and EE savings through Q4 of 2024, as well as forecasted achievements through 2025 as a result of successful plan deployment.

Figure 2-1. Heat Pump and EE Actual for 2024 Q1 and Forecasted for 2024 Q4





In **Figure 2-1** the 2025 planned cumulative savings achievement of 7.45 TBtu, reflects savings calculated in the same manner used by the rest of the New York State electric utilities. In alignment with the New York State utilities, achievement does not include heating penalties. It should be noted that the slight underrun of 7.85 TBtu target is due to the loss of residential lighting as an eligible measure for roughly two and a half years of the overall period of performance. The loss of lighting savings due to the updated Energy Independence and Security Act (EISA) standards[31] (effective June 2023) drastically reduces the programmatic savings not only for PSEG Long Island, but for EE program administrators across the country and is a common understanding amongst the industry stakeholders that there is no new measure that can replace these savings at the scale and cost the lighting measures represented (i.e., recognized for their high efficacy and cost-effectiveness). LED bulbs are still saving energy and generating societal benefits however, the inability to count

[30] Installation numbers reflect whole homes, as well as pool and hot water heaters.
[31] US Department of Energy, Enforcement Policy Statement – General Service Lamps

these savings as a program induced outcome is the reason for the shortfall. The portfolio is transitioning to higher cost EE items, with continued trend of beneficial electrification growing while EE declines. Building electrification and related upgrades improve interior comfort, reduce exposure to air pollution, and support local jobs.

According to the NYSERDA BEEM, that conducted Long Island specific forecasting, Long Island's service territory is expected to yield a target of 67,769 dwellings with heat pumps by the end of the decade. PSEG Long Island is committed to working with 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 photovoltaic (PV) deployments and EV registrations.

In 2025, PSEG Long Island plans to continue to focus on whole house heat pumps (including for income-qualified customers) and an increasing emphasis on pushing customers towards cold climate models with integrated controls while continuing to deemphasize non-cold climate offerings.

2.2. 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 2025 EE initiatives consist of programs for residential customers and multifaceted programs for commercial customers.

PSEG Long Island has been actively engaged in rolling out utility-leading residential and commercial savings programs for customers. The 2025 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.

Early in its 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. Examples of rebate adjustments in response to market conditions include decreasing pool heater rebates down from $1,000 to $600 and increasing thermostats from $50 to $100, in order to drive the market.

The 2025 Plan targets 774,188 total MMBtu savings (which includes 110,059 MWh of EE savings), which are reflected on a gross basis at site. The proposed 2025 budget of $93.71 million for the EE Plan, remaining consistent with the approved budget of $93.71 million in 2024. PSEG Long Island has budgeted for some initiatives that will not have any MMBtu savings associated with them in 2025—e.g., the DLM Program at $2.26 million. 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 portfolio of EE programs will total about $20.01 million in spending in 2025.

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.

2.2.1. Portfolio Summary

Table 2-1 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 2-1. 2025 EE Goals

Program	Savings (MMBtu)	Savings (MWh)	Program Budget ($M)
Energy Efficient Products	155,564	8,887	8.11
Home Comfort	182,387	3,570	26.96
REAP (Low-Income)	13,588	1,201	3.37
Home Performance	39,595	2,418	10.93
Multifamily	64,882	5,108	6.60
All Electric Homes	--	--	0

Program	Savings (MMBtu)	Savings (MWh)	Program Budget ($M)
Commercial Efficiency	185,171	49,896	23.59
Home Energy Management[32]	133,000	38,980	2.19
Total, Budget Components with Programmatic Savings	**774,188**	**110,059**	**81.73**
DLM Program	-	-	2.26
PSEG Long Island Labor	-	-	3.53
Outside Services	-	-	2.43
Advertising	-	-	2.60
G&A	-	-	0.90
Community Solar	-	-	0.25
Total, Budget Components Not Associated with Programmatic Savings	**-**	**-**	**11.98**
Total	**774,188**	**110,059**	**93.71**

Table 2-2 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 (i.e., heat pump technologies) of the overall goals outlined in **Table 2-1**.

Table 2-2. 2025 Heat Pump Goals

Program	Savings (MMBtu)	Participation (Units[33])	Rebates & Incentives Budget ($M)
EEP - Heat Pump Water Heaters	6,806	600	0.90
EEP - Heat Pump Pool Heaters	41,579	1,400	0.98
Home Comfort Program – Whole House ASHPs	178,960	5,528	18.04

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

[33] Presented in units in alignment with incentive/rebate structure. The goal of 5,330 heat pump dwellings corresponds to Air Source Heat Pumps (5,528 units), Air to Water Heat Pumps (16 units), GSHPs (169 units) and Multifamily (1,516 units).

Program	Savings (MMBtu)	Participation (Units[33])	Rebates & Incentives Budget ($M)
Home Comfort Program – Air to Water Heat Pumps	819	16	0.05
Home Comfort Program - GSHPs	8,997	169	1.00
Home Comfort Program – Heat Pump Water Heaters	7,536	729	1.06
All Electric Homes Program - Heat Pumps[34]	--	--	--
Commercial Efficiency Program and Multifamily - Commercial Heat Pumps[35]	60,608	2,272	5.74
Total	**305,305**	**10,714**	**27.77**

Plans for 2025 also include additional investments in energy affordability for LMI customers through 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 2025 budget and shown below in **Table 2-3**, PSEG Long Island plans on spending $20.01 million on LMI Customers.

Table 2-3. 2025 Income-Eligible Customer Goals

Program	Savings (MMBtu)	Participation (Units)	Rebates & Incentives Budget ($M)
Home Comfort – LMI	58,084	2,669	9.48
REAP	13,588	18,185	3.37
Home Performance - LMI	17,813	1,052	5.96
Marketing & Outreach	-	-	1.20
Total	**89,485**	**21,906**	**20.01**

[34] Includes cold climate Air Source Heat Pumps (ccASHP) , Ground Source Heat Pumps (GSHP), and Heat Pump Water Heaters (HPWH)

[35] Includes Custom Heat Pumps, Commercial Energy Program (CEP) – Heat Pumps, and *Multifamily* (MF) Air-Source Heat Pumps (ASHP) / Variable Refrigerant Flow (VRF)

2.2.2. 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.

PSEG Long Island has historically used two separate tests to screen each program and for the overall portfolio: the societal cost test (SCT) and the utility cost test (UCT). The tests are similar but consider slightly different benefits and costs in determining the benefit-to-cost ratios. The ratepayer impact measure (RIM) test is also conducted to assess impact on utility costs and ratepayer bills from the benefits and costs.

- 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. Energy efficiency measures and beneficial electrification measures are captured in this test.
- 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. Only energy efficiency measures are captured in this test.
- The (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. Only beneficial electrification measures are captured in this test.

PSEG Long Island now uses the SCT as the primary method and has applied the June 2024 BCA Handbook, including the avoided capacity and energy costs from including the carbon costs, to screen its 2025 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 2-4 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 2-4. BCA for 2025 EE Portfolio

Program/Sector	SCT	UCT	RIM
Commercial Efficiency Program (CEP)	**1.82**	**1.31**	**0.64**
Multifamily	**0.99**	**1.34**	**1.47**
Commercial	**1.58**	**1.32**	**1.21**
Efficient Products	2.91	0.39	0.27
Home Comfort	0.91	NA	1.66
REAP	1.13	0.21	NA
Home Performance	0.72	0.23	1.77
All Electric Homes	NA	NA	NA
HEM	1.43	0.94	NA
Residential	**1.15**	**0.38**	**1.52**
Overall Portfolio	**1.25**	**0.82**	**1.42**

Table 2-5 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 2-5. BCA for 2024 EE Portfolio without inclusion of Income Qualified Spending

Program/Sector	SCT	UCT	RIM
Commercial Efficiency Program (CEP)	1.84	1.33	0.64
Multifamily	1.00	1.36	1.48
Commercial	**1.6**	**1.33**	**1.22**
Efficient Products	**2.98**	0.40	**0.27**
Home Comfort	0.91	NA	1.79
Home Performance	1.01	0.50	2.20
All Electric Homes	NA	NA	NA
HEM	1.54	1.00	NA
Residential	**1.35**	**0.60**	**1.58**
Overall Portfolio	**1.42**	**1.05**	**1.46**

Table 2-6 presents the benefit-to-costs ratios for the income qualified portions of the portfolio.

Table 2-6. BCA for 2024 EE Portfolio – Income Qualified Programs

Program/Sector	SCT	UCT	RIM
Home Comfort	0.88	NA	1.39
REAP	1.08	0.20	NA
Home Performance	0.52	0.17	0.00
Residential	**0.77**	**0.18**	**1.33**

Table 2-7 outlines the levelized costs on a MMBtu-basis for each program.

Table 2-7. Levelized Cost[36] Comparisons for 2024 EE Portfolio

Program/Sector	$/MMBtu
Commercial	19.97
Multifamily	***22.45***
Efficient Products	9.62
Home Comfort	30.94
REAP	27.22
Home Performance	46.20
All Electric Homes	NA
HEM	23.89

2.2.3. 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 provides day-to-day management of most of the EE programs offered under the PSEG Long Island brand. PSEG Long Island retains overall planning, budgeting, and advertising functions.

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

Program implementation includes ongoing analysis and continuous improvement of implementation methods in program delivery, market support, and deviations from planned measure mix. Implementation also includes activities such as qualifying new 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.

2.2.4. Clean Energy Hub Coordination

The Long Island Regional Clean Energy Hub has an experienced focus on clean energy, energy efficiency, workforce and economic development, education, home weatherization, health, and housing[37]. PSEG Long Island intends to work with the Clean Energy Hub on all programs, with an increased emphasis on programs catering to low-income populations. This coordination effort will be supported through routine monthly meetings, as well as information sharing regarding plans and activities on a programmatic basis.

2.2.5. Energy Savings Portfolio of Programs

Table 2-8 lists the programs offered under this Plan that are administered by TRC and PSEG Long Island.

[37] Long Island Regional Clean Energy Hub (lismartenergychoices.org)

Table 2-8. 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 • Home Comfort Program • REAP • Home Performance Weatherization Program • All Electric Homes • Multifamily • Commercial Efficiency Program (CEP)	• Home Energy Management (HEM) - Behavioral Initiative • DLM Tariffs

2.2.6. Evaluation, Measurement, and Verification

PSEG Long Island has a third-party consulting firm 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 will produce two volumes: Volumes I and II. Together, these volumes will comprise the entire Annual Evaluation report. Volume I will provide an overview of evaluation findings, including impact and process results for 2024. Volume II of the 2024 Annual Evaluation Report, the Program Guidance Document, will provide 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 (claimed) 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 2024 EE portfolio investments, where the 10-year economic impacts accrue from measures installed in 2024 over their remaining measure life.

2.2.7. 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 and also communicate the benefits of EE to niche sectors allowing PSEG Long Island to target parameters 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 most about how to save energy and money. Explaining to them that they have a choice when it comes to lowering their bill improves customer opinions of PSEG Long Island.

PSEG Long Island believes the right media mix and frequency is important to reinforce the overarching EE message about affordability, efficiency, and savings. 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 marketing for program conversions, lead generation and enrollments such as Home Comfort, Geothermal, or Home Performance, PSEG Long Island uses a more tactical approach with targeted emails, direct mail, and digital ads.

Additionally, in 2023, the utility was tasked with designing and executing a marketing plan to build awareness, education, and demand while reducing heat pump adoption barriers for PSEG Long Island customers. This strategy includes a focus on DACs utilizing propensity modeling to identify potential customers and deploy highly targeted outreach for increased take rates. This is described in greater details in 2.2.8.

Over the last 10 years, PSEG Long Island has successfully implemented numerous campaigns to drive overall EE awareness, increase energy affordability and support clean energy goals. In 2024, the EE paid advertising campaign has delivered nearly 30,000,000 impressions across social media, digital display, search engine marketing (SEM), Out Of Home, door hangers, and connected TV. PSEG Long Island also 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. This strategy will continue into 2025 and beyond.

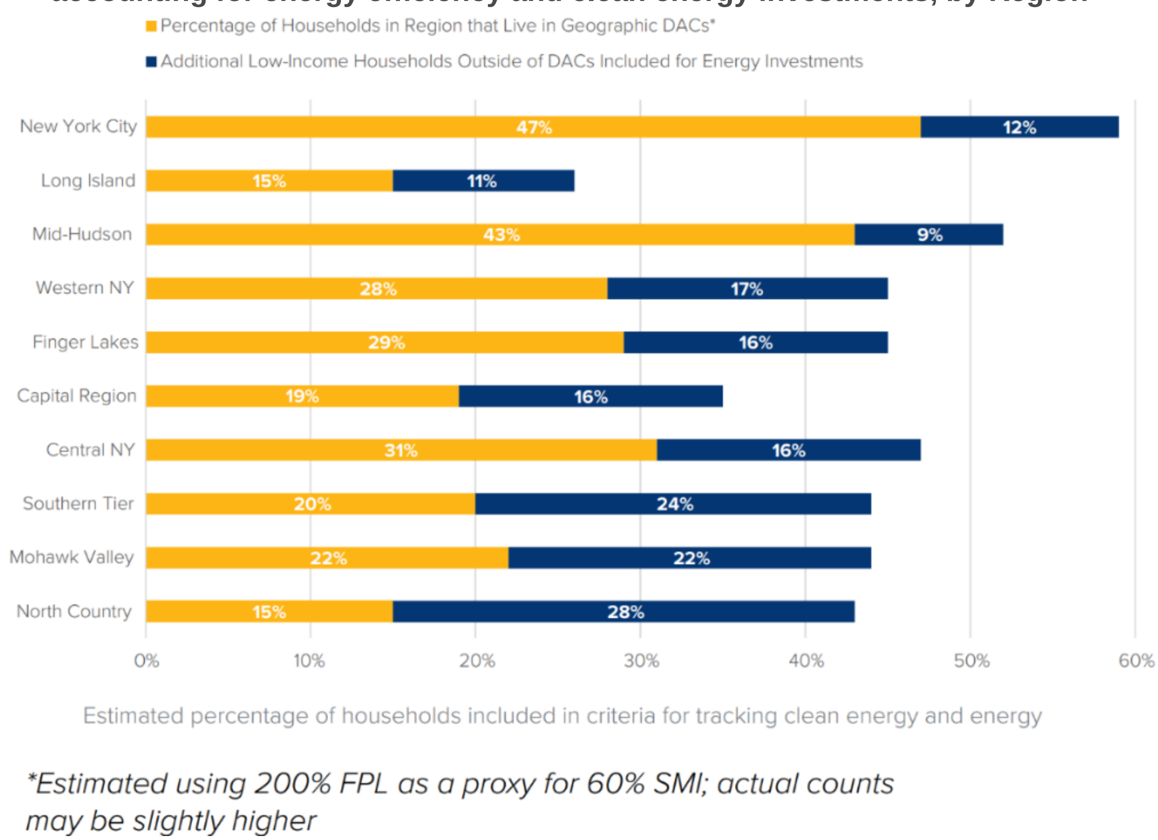
2.2.8. Disadvantaged Communities

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 Energy Efficiency and Clean Energy benefits to residential and business customers in DACs or in income-qualified households. While the benefits accruing to DACs are inclusive of economy-wide investments that are broader in scope than just clean energy and EE programs, this chapter is primarily concerned with the EE benefits. The EE Plan focuses on the delivery of EE and beneficial electrification to DAC and LMI customers.

While the CJWG voted to accept criteria on March 27, 2023, expenditures are currently the primary reporting metric as opposed to benefits, which have yet to be defined. As of the publishing of the 2024 Utility 2.0 Plan and EE Plan, PSEG Long Island has populated draft templates for calendar years 2020, 2021, 2022, and 2023, and submitted the draft templates to LIPA for QAQC purposes. We expect to submit our data for the statewide reporting in accordance with the final schedule NYSERDA puts forth.

PSEG Long Island is committed to supporting its customers residing in DACs and recognizes that the opportunity to reach the statewide goal of 35% spending towards DAC is limited within the Long Island territory due to the demographic of its constituency relative to the rest of New York State. This is made clear by the initial analysis released by the Climate Act Task Force (see **Figure 2-2)** in which PSEG Long Island's service territory is comprised of approximately 26% of households meeting the DAC and LMI criteria, whereas the rest of utilities saw a higher percentage of potentially eligible households in their service territory, between 35% and 59%.

Figure 2-2. Increase in number of households included in DAC criteria for purposes of accounting for energy efficiency and clean energy investments, by Region[38]



The onboarding of ICF Next in 2021 as the utility's advertising agency has afforded new options in promoting EE. In addition to the mass media advertising that PSEG Long Island

[38] New York States Draft Disadvantaged Communities Criteria, *9/2023*

uses to communicate the multiple benefits of its EE programs across Long Island and the Rockaways, in 2025, 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 continue to implement and seek opportunities to create multilingual materials in at least one other language, to accommodate communities where English is not the first language.

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

In addition to marketing and advertising, communications, and public affairs, PSEG Long Island's business customer advocates will also help in the ongoing outreach and awareness of the Utility's EE programs. Collaboration with events such as Community Wide Energy Forums in DACs are also being developed to further DAC outreach and engagement.

PSEG Long Island has the capability to report upon customer program participation by census tract allowing the Utility to focus and identify customers within DAC communities. Now that 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, 2025 DAC customer program participation is in line with the 35% state goal established for the Long Island electric service territory.

2.3. Energy Efficiency and Heat Pumps Products and Programs

The following sections provide details on the programs offered in 2025. 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.

2.3.1. 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 linear fixture lighting among PSEG Long Island residential customers by providing rebates and incentives. The EEP engages with customers and retailers to promote the program and increase the market penetration of efficient products primarily by financially incentivizing consumers. Measure 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 EEP program promotes energy efficient measures like Energy Star-certified linear LED lighting, Energy Star appliances, heat pump pool heaters, advanced power strips, and Energy Star Heat Pump Water Heaters. 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 addition to providing rebates and 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.

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.

2.3.1.1. Notable Changes

In the 2024 Program Year, the recycling program was discontinued. The Recycling Program was expected to sunset at the end of 2025. Resultantly, PSEG Long Island discontinued the program early, to allocate program funds to impactful measures like Smart Thermostats. Also in 2024, the EEP Team relaunched the Heat Pump Pool Heater Partner Program. Heat Pump Pool Heater installers can become “Partners” by providing a signed Partner Agreement and providing required documents such as a W-9. The relaunch of this Partner Program allows the EEP Team to engage more with these installers and increase program participation.

A notable program update for the 2025 EEP Program is the program delivery channel for Heat Pump Water Heaters. Historically, Heat Pump Water Heaters have been rebated downstream, through the PSEG Long Island Online Application (OLA). Beginning in 2025 Heat Pump Water Heaters will be available through a Midstream approach. The EEP team will be working with different retailers, distributors, and installers, to promote this offering and increase the number of Heat Pump Water Heater participants.

2.3.1.2. 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 POS incentives.

Upstream Incentives

Upstream incentives are payments to manufacturers or suppliers to stock, promote, and sell Energy Star-certified linear lighting products, Room Air Purifiers, Dehumidifiers, Advanced Power Strips, and Smart Thermostats. PSEG Long Island can buy-down the wholesale price rather than the retail product price by directing the incentive to the manufacturer or supplier. The manufacturer is then able to sell the product at a reduced rate to the retailer or distributor which then typically results in a greater reduction of the retail price. Manufacturer reimbursement is based on the submission and verification of sales data.

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.

To implement an upstream program, Program Agreements (PA) are required between appropriate parties, including the suppliers and manufacturers. Several PAs have been negotiated with manufacturers and suppliers to support the EEP. PAs 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 payments to manufacturers and retailers (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.

Midstream Incentives

Midstream incentives are paid to distributors or retailers to reduce the customer point of sale price for measures like Room Air Purifiers, Smart Thermostats, and Dehumidifiers. The incentive is passed directly down to the customer. Distributors and retailers who participate in the Midstream program, bi-monthly, provide PSEG Long Island with transaction data that is vetted prior to reimbursement.

The implementation steps of the program are very similar to the steps mentioned above in the "Upstream Incentives" section.

The objective of providing midstream incentives is to influence the distributors and/or retailers to stock and promote energy efficient equipment.

Downstream Rebates

Downstream rebates are payments paid to end-use customers who purchased qualifying equipment and applied for a rebate. TRC processes all rebates and develops marketing collateral that the EEP field representatives utilize to discuss promotions and establish relationships/engage 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 in store 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.

Marketplace Incentives

PSEG Long Island hosts an online product Marketplace for eligible PSEG Long Island residential customers. The Marketplace includes equipment such as, Smart Thermostats, Advanced Power Strips, Air Purifiers, and more. Historically, lighting measures were also offered on the Marketplace. The Marketplace has proven to be a large driver in EEP participation from the legacy standard and specialty bulbs offering to the continuing Smart Thermostat offering.

The Marketplace is a strategic customer engagement mechanism as a customer may be looking solely for a Learning Smart Thermostat and discover the other energy efficient equipment opportunities at their fingertips.

Per the latest NE:NY and New York State guidance, Utility Marketplace offerings and platforms are expected to be phased out after 2025, as most measures on the Marketplace may be considered “non-strategic”. The Marketplace should continue to be in place after 2025 due to the strategic engagement nature of the Marketplace as well as continuing to incentivize measures like Smart Thermostats. It is also important to note that there will be cross program promotion between REAP and EEP as well as Home Performance and EEP, beginning in 2025. The REAP Program and the Home Energy Assessment through the Home Performance Program historically provided customers with Advanced Power Strips. In 2025, the Advanced Power Strip offering will be replaced with a Marketplace Voucher, in both programs. This shift to the Marketplace Voucher will bring more attention to the Marketplace, allowing the customer to explore other energy efficiency equipment and learn more about other PSEG Long Island Programs. The Marketplace Voucher can be applied to measures such as Dehumidifiers, Smart Thermostats, or other measures promoted in the energy efficiency program.

The EEP program implementation model described above is intended to remain in place through 2025. Please note, beginning in 2026, the EEP model and measure mix will be adjusted to remove all "non-strategic" measures in accordance with the NE:NY guidance.

2.3.1.3. Target Market

All PSEG Long Island residential customers.

2.3.1.4. Measures and Incentives

Table 2-9 lists the measures offered in the EEP program. "Measure Incentives" refer to the point of sale customer incentive to reduce the upfront cost of a measure, or in the case of the Heat Pump Pool Heater the incentive provided to the contractor for installation. "Measure Rebates" refer to the rebate provided to the customer after equipment purchase and rebate application submittal.

Induction cooktops have been added to the 2025 program offering. Most Efficient Dryers have been removed due to lack of participation in this measure category.

It should be noted that in 2026 and beyond, the measure mix may not be as robust as previous years. This is due to the guidance in the NE:NY order that suggests all "non-strategic" measures, like Dehumidifiers, should no longer be offered.

Table 2-9. EEP: List of Measures

Measure	2025 Planned Units	Measure Incentives	Measure Rebates
Advanced Power Strips (Tier I) - Midstream/Upstream	1,600	$15	-
Most Efficient Clothes Washers - Downstream	2,000	-	$60
Heat Pump Water Heater < 55 gallons - Midstream	500	$300	$1,200
Heat Pump Water Heater > 55 gallons - Midstream	100	$300	$1,200
ES Dehumidifiers – Midstream/Upstream	5,000	$35	-
ES Room Air Purifiers (<150 CADR) - Midstream/Upstream	2,000	$30	-
ES Room Air Purifiers (>150 CADR) - Midstream/Upstream	1,800	$40	-
ES Dryer - Electric Resistance - Downstream	1,200	-	$25
Induction Cooktop - Downstream	150	-	$150
Smart Thermostats - Connected (Wi-Fi Enabled)- Midstream/Upstream	10,000	-	$100

Measure	2025 Planned Units	Measure Incentives	Measure Rebates
Smart Thermostats - Learning – Midstream/Upstream	6,000	-	$130
Heat Pump Pool Heaters - Downstream	1,400	$100	$600
LED Linear Fixtures – Midstream/Upstream	25,000	$4	-

2.3.1.5. Outreach

The EEP program utilizes a variety of outreach strategies, and informative collateral, to ensure that customers are aware of the rebates/incentives available for Energy Star appliances and beneficial electrification equipment. Strategies include broad brush and marketing via:

- Limited-time offer e-blast promotions
- Direct Mail promotions
- Bill inserts
- Digital display ads
- Social media posts
- POP 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

In 2024, and expected to continue into 2025, Outreach efforts for measures like Smart Thermostats and Heat Pump Pool Heaters increased to bring more awareness to the importance of these measures. There were several promotions for Smart Thermostats for occasions like Earth Month and promotions going into the summer season. To support the Manufacturers promotion of Smart Thermostats, the EEP launched direct mail campaigns in the form of informative postcards to alert customers of the promotion through the

Marketplace. There was also a great emphasis on Heat Pump Pool Heater targeted marketing through a third-party data analytics tool called Lightbox. Lightbox collects customer data like construction data, building characteristics, historical customer billing data, and more. Lightbox provided a pathway for the EEP team to understand how many customers in the PSEG Long Island territory have purchased pools and may benefit from participating in the EEP Heat Pump Pool Heater rebate offering. Those identified customers will be included in a direct mail campaign focused on increasing Heat Pump Pool Heater rebate opportunities.

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.

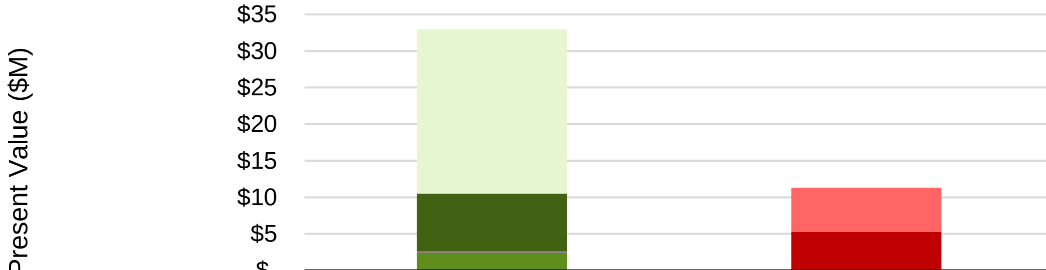
A notable outreach strategy implemented in the 2023 Program Year was Food Bank engagement. Throughout the 2023 program year, the EEP program coordinated with several Food Banks to provide LED Bulbs to customers in need. Since this initiative supports the low-income community and low-income program awareness, 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. The EEP program will build upon the success of the Foodbank initiatives in 2024 and 2025 to provide a non-lighting alternative support for the low-income community, like advanced power strips or low flow showerheads.

2.3.1.6. Business Case

The EEP program has a SCT benefit-to-cost ratio of 2.91 and RIM benefit-to-cost ratio of 0.27. A list of the value streams considered in the BCA is detailed in **Figure 2-3** and **Table 2-10**.

![PSEG Long Island]

Figure 2-3. Energy Efficiency Products Present Value Benefits and Costs of SCT



	Benefit	Cost
Fuel Switching Benefits	22.43	-
Net Avoided SO2 and NOx	0.000239	-
Net Avoided CO2	7.88	-
Avoided Distribution Capacity Infrastructure	0.11	-
Avoided Transmission Capacity Infrastructure	0.12	-
Avoided Energy (LBMP)	2.32	-
Avoided Generation Capacity Cost (AGCC)	0.07	-
Participant DER Cost	-	6.09
Program Administration Costs	-	5.23
Total	32.93	11.31

Table 2-10. 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.	22.43	
2	**Net Avoided SO_2 and NOx**	Reduced SO_2 and NOx from reduced energy consumption.	0.000239	
3	**Net Avoided CO_2**	Reduced carbon emissions from reduced energy consumption and beneficial electrification.	7.88	
4	**Avoided Distribution Capacity Infrastructure**	Based on demand savings and marginal distribution capacity cost.	0.11	
5	**Avoided Transmission**	Based on demand savings and marginal transmission capacity cost.	0.12	

#	Value Stream	Calculation Methodology	Benefits (NPV, $M)	Costs (NPV, $M)
	Capacity Infrastructure			
6	**Avoided Energy (LBMP)**	Energy savings based on both on-peak and off-peak periods.	2.32	
7	**Avoided Generation Capacity Cost (AGCC)**	Based on demand savings and marginal capacity cost.	0.07	
8	**Participant DER Cost**	Includes cost of incremental equipment and installation.		6.09
9	**Program Administration Costs**	Includes contractors fee, labor, evaluation, and advertising costs.		5.23
	Total Benefits		**32.93**	
	Total Costs			**11.31**
	SCT Ratio		**2.91**	

2.3.2. 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 Whole House Air Source Heat Pumps (ASHP). ASHPs are typically two to three times more efficient than traditional fossil fuel space heating systems. The Home Comfort Program rebates efficient whole house cold climate ducted and ductless systems and controls. New in 2024, whole house air to water heat pump systems were introduced.

The objective of the Home Comfort Program is to evolve with the market and work towards 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. To further align with New York State's home electrification goals, Whole House cold climate air source heat pumps are emphasized through this program. Partial House heat pump rebates were discontinued in 2023. A Whole House installation can be defined as an ASHP system designed/sized to meet the heating and cooling load of the entire home. The Whole House ccASHP system must be the primary heating system for the home; however, integrated controls are allowable if a customer opts to keep their existing fossil fuel heating system as a secondary heating source.

Based on the Heat Pump barriers identified by LIPA in 2023 year, PSEG Long Island has been continually working to address and overcome obstacles regarding heat pump uptake, including streamlining the application process, conducting more training sessions, case studies, collaboration with KEDLI and other utilities where applicable. The creation of a Heat Pump Economics Calculator can be found on the PSEG webpage, for both contractors and customers, to easily and accurately get estimated costs and rebates for a heat pump installation.

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. Market Rate and Income Eligible rebates for Whole House Air Source Heat Pump equipment are calculated based on the total heating capacity of the equipment at the 17°F rated heating capacity and are subject to a total project rebate cap.

The Home Comfort application contains all heat pump and weatherization measures:

- Ducted/Ductless Cold Climate Air Source Heat Pumps
- Air to Water Heat Pumps
- Integrated Controls
- Weatherization (Duct Sealing, Air Sealing, Insulation, Windows)
- Heat Pump Water Heaters

Income eligible rebates have been available since 2021 and are referred to as "Home Comfort Plus" rebates. In order to qualify for income eligible rebates, customers meet the 60% SMI eligibility requirements as set forth by NYSERDA EmPower. 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.

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 Home Comfort partners to positively influence the customer on the benefits of program participation.

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

2.3.2.1. Notable Changes

Whole House Air to Water Heat Pumps were introduced to the Home Comfort Program in April 2024. Air to Water Heat Pumps began to emerge as a reoccurring topic during discussions with New York State's Joint Utilities group in June of 2023. Air to Water Heat Pumps distribute heat in the home using hydronic or hot water systems instead of ductwork. Systems typically operate over a range of leaving water temperatures (LWTs) from 90°F to 140°F. It should be noted that certain models can exceed this range. To align with the Joint Utilities, PSEG Long Island incorporated the Air to Water Heat Pump offering in the Home Comfort Application in April 2024. Rebates are available for both Market and Income Eligible customers and match the Cold Climate Air Source Heat Pump rebate structure. New York State created its own Qualified Products List (QPL) for all eligible Air to Water Heat Pumps. The Air to Water Heat Pump QPL is integrated in the Home Comfort workbook to allow for seamless equipment eligibility and data population. Upon selection of the Air to Water Heat Pump equipment, all efficiency and equipment data will auto populate.

PSEG Long Island also did a significant overhaul of the Whole House Cold Climate Air Source Heat Pump worksheet for the 2024 Home Comfort Application. Historically, Home Comfort Partners had to enter all existing equipment data and efficiencies, new equipment data and efficiencies, as well as Manual J data in the Home Comfort Application. Because all equipment must be on the NEEP List, the NEEP List was integrated into the application. The Partner will enter the AHRI Certification Number in the application and all equipment data will auto populate. The Partner will still have to complete the Manual J calculations and enter those values in the workbook to ensure the equipment is being properly sized for the customer. The addition of the NEEP List into the workbook has reduced the number of Partner inputs by 12 inputs.

In addition to the streamlined Home Comfort application, PSEG Long Island will also introduce a Data Collection phone app. The phone app may be used in place of the Excel based Home Comfort application. The phone app will have many of the same streamlined features as the Excel based workbook but will include a speedier solution for submitting documents and photos of the existing and the installed equipment.

In 2025, similar to 2024, 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 2025 Whole House Cold Climate Air Source Heat Pump planned unit count is approximately 85% higher than the 2024 planned unit count. The number of Whole House Cold Climate Air Source Heat Pumps increased by 152% for Income Eligible units and 65% for non-Income Eligible units. The Whole House Cold Climate Air Source Heat Pump unit count in the 2024 Plan was 2,991 units. The Whole House Cold Climate Air Source Heat Pump unit count in the 2025 Plan is 5,526 units.

Please note, the "equipment only" air source heat pump offering that was launched in 2021 will be discontinued in 2025.

2.3.2.2. 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 2025, all heat pump projects will require installation by a QIV Home Comfort partner.

Ground Source Heat Pump (GSHP) systems are a component of the Home Comfort Program; however, GSHP projects are completed on the standalone Geothermal Rebate Application. The standalone application historically accommodated both Residential and Commercial projects; however, in 2024 the application was updated to reflect the Residential Ground Source Heat Pump offering only, as all Commercial Ground Source Heat Pump projects are better suited for the Custom program and the New York State Clean Heat Calculator tool. Ground Source Heat Pump rebates are available for both market and income eligible customers. It should be noted that in 2024, the rebate structure remained the same, but rebate calculations shifted from cooling load to heating load to be consistent with cold climate air source heat pump rebate calculations.

2.3.2.3. Target Market

The Home Comfort program, inclusive of Ground Source Heat Pumps, is offered to all residential customers in the PSEG Long Island service territory. Enhanced Low Income rebates are offered to all eligible customers.

2.3.2.4. Measures and Incentives

A list of measures that are offered in the Residential Home Comfort program is included in **Table 2-11**. Please note, in the below table "Measure Rebate" refers to the rebate for the installed equipment. "Measure Incentive" refers to the contractor incentive.

Table 2-11. Residential Home Comfort Program: List of Measures

Measure[39]	2025 Planned Units	Measure Incentives	Measure Rebates[40]
Integrated Controls	2,875	-	$500
Integrated Controls – Low Income	731	-	$750
ccASHP (QI) – Whole House Electric Baseline	25	$500	$2,007
ccASHP (QI) – Whole House Electric Baseline (Low Income)	8	$500	$4,465
ccASHP (QI) – Whole House Fossil Fuel Baseline	3,725	$500	$2,007
ccASHP (QI) – Whole House Fossil Fuel Baseline (Low Income)	1,693	$500	$4,465
ccASHP (QI) – Whole House New Construction	75	$500	$2,007
ccASHP (QI) – Whole House New Construction (Low Income)	2	$500	$4,465
GSHP De-Superheaters	20	-	$250
GSHP Tier I	20	$200	$3,000
GSHP Tier II	145	$200	$6,000
GSHP Tier I LMI	1	$200	$6,000
GSHP Tier II LMI	3	$200	$12,000
GSHP Water Heater	3	-	$1,000
GSHP Water Heater LMI	1	-	$1,500
Heat Pump Water Heater ≤ 55 Gallons	300	$100	$1,200
Heat Pump Water Heater > 55 Gallons	200	$100	$1,200

[39] *Measure Name includes existing equipment scenario – e.g., "Whole House Fossil Fuel Baseline" indicates the existing equipment is a fossil fuel heating system*

[40] *"Measure Rebates" in the above table reflect per system rebates, based on 2025 planning assumptions*

Measure[39]	2025 Planned Units	Measure Incentives	Measure Rebates[40]
Heat Pump Water Heater ≤ 55 Gallons LMI	150	$100	$1,700
Heat Pump Water Heater > 55 Gallons LMI	75	$100	$1,700
Air to Water Heat Pump – Whole House	11	$500	$2,030
Air to Water Heat Pump – Whole House - LMI	5	$500	$4,516

2.3.2.5. 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 launched 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 increase 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 to develop training, heat pump promotion, and workforce development initiatives, which are currently not available on Long Island
- Launch Air to Water Heat Pump offering

As of May 2024, the below activities have taken place:

- Distributed and collected Program/Tool Survey results
  - Results from this survey influenced items such as Home Comfort Application streamlining, trainings opportunities, and addition of tools added to list of tool reimbursements
- Hosted a Home Comfort Partner Round Table and Distributor Round Table
- Hosted a Heat Pump Conference geared towards Partners/Manufacturers/Distributors
- Launched "Smart Tools" tool reimbursement application
  - Expansion of the number of tools reimbursed
- Distributed pre-recorded Webinar on IRA funding
- Launched "Home Comfort Highlights" monthly newsletter
  - General Program Updates
  - Training Updates – NYSERDA Clean Heat Connect & Home Comfort Program
  - NYSERDA Workforce Development Funding Opportunities
- Launched "Home Comfort Counter Days" at distributor locations
  - Home Comfort Team presence at distributor locations
- Published first and second round case studies on the PSEG Long Island website
- Included Air to Water Heat Pumps in Home Comfort application and increase in manufacturer/distributor engagement
- Increased number of locations providing Home Comfort QIV Partner Training

- Launched ACH Payment Pilot with 1 high performing, high quality partner
    - Pilot has since expanded to include 3 high performing, high quality Home Comfort Partners

It should be noted that in 2023, a "Partner Program Design Analyst" full time position was created to support all facets of Home Comfort Partner support and growth. The Partner Program Design Analyst is responsible for facilitating and supporting all of the above mentioned activities. The Partner Program Design Analyst position was filled in October 2023. This position will continue to support growth in the Home Comfort Partner network through 2025 and beyond.

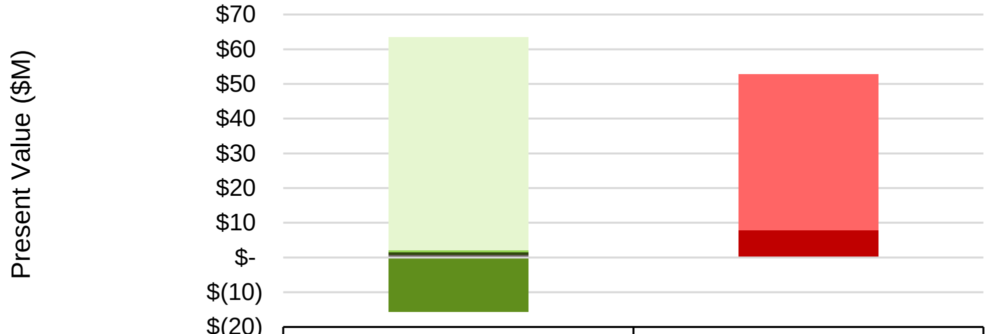
As referenced in the above "activities" list, in April 2024 PSEG Long Island hosted its first ever "Heat Pump Technologies and Solutions Conference" geared towards manufacturers, distributors, and installers. There were 15 different breakout sessions focusing on topics like Air Source Heat Pumps 101 to the New York State Clean Heating Tool. Over 550 attendees participated in the informative event. The next "EE" conference is scheduled to be held on November 7, 2024.

In conjunction with the Partner Program Design Analyst activities, the Home Comfort team, along with the Home Performance team offer virtual and in-person training sessions to maintain contractor engagement. The Home Comfort subject matter experts host open houses and webinars, providing a platform for Partners to learn more about important program components such as the methodologies behind Manual J Load Calculation and best practices. Heat Pump focused trainings have demonstrated high level of contractor engagement and ensure the contractors have the tools necessary to reach and engage customers. Virtual and In-Person methods will continue to be available to allow all Partners to remain engaged with the program.

2.3.2.6. Business Case

The Home Comfort program has a SCT benefit-to-cost ratio of 0.91 and RIM benefit-to-cost ratio of 1.66. A list of the value streams considered in the BCA is detailed in **Figure 2-4** and **Table 2-12**.

Figure 2-4. Residential Home Comfort Program Present Value Benefits and Costs of SCT



	Benefit	Cost
Fuel Switching Benefits	61.37	-
Net Avoided SO2 and NOx	0.000643	-
Net Avoided CO2	0.65	-
Avoided Distribution Capacity Infrastructure	0.61	-
Avoided Transmission Capacity Infrastructure	0.44	-
Avoided Energy (LBMP)	(15.61)	-
Avoided Generation Capacity Cost (AGCC)	0.37	-
Participant DER Cost	-	44.80
Program Administration Costs	-	7.94
Total	47.83	52.74

Table 2-12. 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.	61.37	
2	**Net Avoided SO_2 and NOx**	Reduced SO_2 and NOx from reduced energy consumption.	0.000643	
3	**Net Avoided CO_2**	Reduced carbon emissions from reduced energy consumption and beneficial electrification.	0.65	
4	**Avoided Distribution Capacity Infrastructure**	Based on demand savings and marginal distribution capacity cost.	0.61	

#	Value Stream	Calculation Methodology	Benefits (NPV, $M)	Costs (NPV, $M)
5	**Avoided Transmission Capacity Infrastructure**	Based on demand savings and marginal transmission capacity cost.	0.44	
6	**Avoided Energy (LBMP)**	Energy savings based on both on-peak and off-peak periods.	(15.61)	
7	**Avoided Generation Capacity Cost (AGCC)**	Based on demand savings and marginal capacity cost.	0.37	
8	**Participant DER Cost**	Includes cost of incremental equipment and installation.		44.80
9	**Program Administration Costs**	Includes contractors fee, labor, evaluation, and advertising costs.		7.94
	Total Benefits		**47.83**	
	Total Costs			**52.74**
	SCT Ratio		**0.91**	

2.3.3. 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

All customers who participate in the REAP Program must meet the income eligibility criteria. The income eligibility criteria are based on 80% SMI. Prior to 2023, the income eligibility was based on the 80% Area Median Income. The purpose of this adjustment is to move towards the statewide income eligibility threshold (60% of SMI as per NYSERDA EmPower) while still addressing the higher cost of living in Nassau and Suffolk counties in comparison to New York State.

2.3.3.1. Notable Changes

In the 2024 program year, notable changes include launching the installation of weatherization improvements and expanding installation of the water conservation measures to oil and propane customers. Natural Gas customers are not eligible as National Grid provides water conservation measures through the HEAP program to its customers. Please note, refrigerators were initially removed from the REAP Program but added back in to the 2024 measure mix to maximize the positive customer benefits of program participation. The new weatherization measures include Attic Insulation, Attic Tent Insulation, Door Sweeps, Duct Sealing, Water Heater Blanket (electric DHW only), and Pipe Insulation. All customers may receive the weatherization improvements. The water conservation measures have historically been offered through the REAP Program but for electric water heating customers only. Since the EE Program goals are measured in MMBtus, the expansion of eligibility to allow oil customers is a natural progression as savings are claimed based on the water heater fuel type.

To maximize benefits to REAP participants, Smart Thermostats will continue to 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. Through the education component of the program, the REAP Technician is also able to educate the customer on heating and cooling behaviors. The Smart Thermostats will be enrolled in PSEG Long Island's Smart Savers program for customers with Central Air Conditioning systems.

To further engagement customers and provide more participation benefits, a new "Bill Credit" initiative was launched in 2024.The "Bill Credit" promotion provides each REAP participant with a $50 Bill Credit on a future PSEG Long Island electric utility bill. All new REAP customers are eligible for this promotion. This initiative is likely to be available in the 2025 Program Year.

2.3.3.2. 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 customers who can be identified as income eligible. Customers who are identified through these efforts are offered a free comprehensive home energy survey and energy savings educational materials. The free services and materials are intended to convert the customer in to a REAP program participant.

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 and communicating directly with the customer. In anticipation of the upcoming REAP survey, customers receive an email notification and pre-survey communication to complete that highlights the key characteristics of the home. To provide flexible scheduling options for the customers, in the summer of 2024, REAP launched a new customer scheduling tool called “Calendly.” Calendly is a communication platform that eases the scheduling process between the customer, REAP Program implementers, and the REAP technicians. Calendly allows customers to schedule/reschedule/cancel appointments themselves online. Customers will receive text and email communications regarding their scheduled appointment. Calendly will have the three REAP Territory’s embedded. As a customer schedules their appointment, the appointment will be routed to the correct REAP Territory and the correct REAP Technician. By deploying Calendly, the REAP Team is automating, and increasing, customer appointment communications, while also giving the customer more control of their appointment.

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.

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
    - $50 Bill Credit Promotion

- Calling and door to door canvassing for potential REAP participants
- Providing participants with the 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, the behaviors 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 in writing, 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 the customer 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 (Mini-Application); 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 2023, the Energy Forum was held in-person and boasted over 130 attendees.

2.3.3.3. 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 2-13** below.

Table 2-13. 2024-2025 REAP Income Guidelines[41]

Size of Family	Maximum Gross Monthly Income	Maximum Gross Annual Income
1	$4,047	$48,560
2	$5,293	$63,520
3	$6,539	$78,464
4	$7,784	$93,408
5	$9,029	$108,352
6	$10,275	$123,296
7	$10,508	$126,096
8	$10,741	$128,896
9	$10,975	$131,696
10	$11,209	$134,512

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 the 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 SMI. These criteria exceed the 60% of SMI required for CLCPA DAC income compliance. The income guidelines in the Climate Act align with the NYSERDA EmPower income guidelines which reflect 60% of the SMI. The Microsoft Dynamics CRM platform that PSEG Long Island utilizes for all reporting, includes fields that are used to identify if a customer meets the 60% SMI threshold or the 80% SMI threshold.

[41] *Based on 80% of SMI.*

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 Energy Efficiency Programs.

Based on 2023 completed projects where we have available data on income, approximately 87% of all REAP customers meet the income criteria of 60% of SMI while the remaining 13% of customers fall into the "moderate" income bracket of 80% SMI.

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 ______________________________

2.3.3.4. Measures and Incentives

Measures offered through the REAP program are summarized in **Table 2-14** below.

Table 2-14. REAP: List of Measures

Measure	2025 Planned Units	Measure Incentives	Measure Rebates
Dehumidifiers 25-50 Pints/Day	95	-	-
Dehumidifiers >50 Pints/Day	115	-	-
ES Room Air Purifiers (<200 CADR)	100	-	-

Measure	2025 Planned Units	Measure Incentives	Measure Rebates
ES Room Air Purifiers (>200 CADR)	230	-	-
Water Temperature Turndown/HH	10	-	-
Faucet Aerators/unit	400	-	-
Low Flow Showerheads/unit	180	-	-
Thermostatic Valve	135	-	-
10,000 Btu RAC 1 Unit/HH	55	-	-
12,000 Btu RAC 1 Unit/HH	50	-	-
6,000 Btu RAC 1 Unit/HH	450	-	-
8,000 Btu RAC 1 Unit/HH	125	-	-
Pipe Insulation/ln ft - Electric ONLY	215	-	-
Nightlight	1,575	-	-
LED Bulbs	10,000	-	-
Smart Thermostats - Connected - LMI Direct Install	1,000	-	-
16 cf Refrigerator	30	-	-
18 cf Refrigerator	60	-	-
21 cf Refrigerator	60	-	-
Attic Insulation R-19	200	-	-
Air Sealing	200	-	-
Duct Sealing	200	-	-
Attic Hatch Insulation	200	-	-
Water Heater Blanket Insulation - Electric Only	100	-	-
Door Sweep	200	-	-
Pipe Insulation/ln ft - FF Baseline	200	-	-

It is estimated that 2,000 REAP visits will be conducted in the 2025 program year for customers who meet the income eligibility threshold. 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 2-15**).

- **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 2-15. 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 water heater temperature settings* Thermostatic Shower Valves* Smart Thermostats Attic Tent Insulation Attic Insulation Door Sweeps Air Sealing Duct Sealing Water Heater Blankets**	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 and newly provided to oil customers.*

***Water Heater Blankets 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.

Please note, historically, REAP participants received Tier 2 Advanced Power Strips as a part of the REAP visit. Beginning in 2025, the Advanced Power Strip will be replaced with a PSEG Long Island Marketplace Voucher. The Marketplace Voucher can be applied to measures such as, Dehumidifiers, Smart Thermostats, or other measures promoted in the energy efficiency program. The shift in the Advanced Power Strip offering will bring more attention to the Marketplace, allowing the customer to explore other energy efficiency equipment and learn more about other PSEG Long Island Programs.

2.3.3.5. 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 2023/2024 calendar year, the REAP team attended over 103 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 continue collaboration with other organizations and 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.

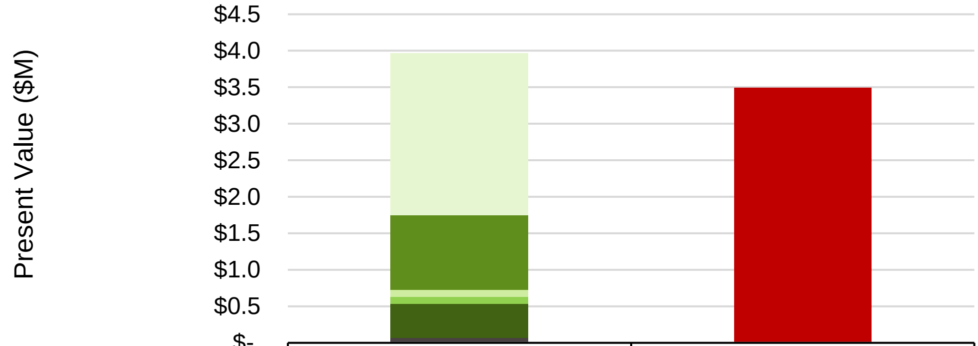
Customers can also reach the REAP program directly through the PSEG Long Island website or through E-blasts that are sent out periodically. Both avenues refer the customer to a REAP mini-application that is sent directly to the REAP team once completed. The E-blast response to the mini-app has resulted in a 31% 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.

2.3.3.6. Business Case

REAP has a SCT benefit-to-cost ratio of 1.13. A list of the value streams considered in the BCA is detailed in **Figure 2-5** and **Table 2-16**.

Figure 2-5. REAP Present Value Benefits and Costs of SCT



	Benefit	Cost
Fuel Switching Benefits	2.22	-
Net Avoided SO2 and NOx	0.000024	-
Net Avoided CO2	1.02	-
Avoided Distribution Capacity Infrastructure	0.10	-
Avoided Transmission Capacity Infrastructure	0.09	-
Avoided Energy (LBMP)	0.47	-
Avoided Generation Capacity Cost (AGCC)	0.06	-
Participant DER Cost	-	-
Program Administration Costs	-	3.49
Total	3.96	3.49

Table 2-16. 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.	2.22	
2	**Net Avoided SO_2 and NOx**	Reduced SO_2 and NOx from reduced energy consumption.	0.000024	
3	**Net Avoided CO_2**	Reduced carbon emissions from reduced energy consumption and beneficial electrification.	1.02	
4	**Avoided Distribution Capacity Infrastructure**	Based on demand savings and marginal distribution capacity cost.	0.10	

#	Value Stream	Calculation Methodology	Benefits (NPV, $M)	Costs (NPV, $M)
5	**Avoided Transmission Capacity Infrastructure**	Based on demand savings and marginal transmission capacity cost.	0.09	
6	**Avoided Energy (LBMP)**	Energy savings based on both on-peak and off-peak periods.	0.47	
7	**Avoided Generation Capacity Cost (AGCC)**	Based on demand savings and marginal capacity cost.	0.06	
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.		3.49
	Total Benefits		**3.96**	
	Total Costs			**3.49**
	SCT Ratio		**1.13**	

2.3.4. Home Performance with ENERGY STAR

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. Please note, in 2024, due to the "pause" of National Grid's Residential Weatherization Program, PSEG Long Island was able to service all market rate and income eligible natural gas customers. Upon National Grid re-launching its Residential Weatherization program, the historical natural gas eligibility criteria will become effective.

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 who install whole-house heat pumps and weatherization measures. For weatherization measures (duct sealing, air sealing, and insulation) market rate customers can receive up to $1,000 per project and income eligible customers up to $6,250 per project. Rebates are also available for windows and heat pump water heaters. PSEG Long Island works with EFS to qualify income eligible customers, utilizing the NYSERDA EmPower income eligibility requirements of 60% of the SMI. Participating Home Performance partners may also offer Green Jobs Green New York funding for qualified market rate and income eligible customers.

The Home Performance program has built a robust business and partner network. The Home Performance Partners, and various trade allies and constituent-based organizations like NYSERDA, Long Island Green Homes, BPI, BPCA/Efficiency First, and United Way, are key to the success of the Home Performance Program. The Home Performance team works closely with these entities to drive program success and collaboration.

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 HEA.

Customers who participated in the HEA received a “Thank-You Kit” that contained LED Bulbs. In 2023, in recognition of the EISA lighting standards, the “Thank-You Kit” transitioned from lighting to Advanced Power Strips. In 2025, the “Thank-You Kit” will be in the form of a PSEG Long Island Marketplace Voucher. HEA participants will be able to use the Marketplace Voucher on any equipment on the Marketplace they choose. This shift in the “Thank-You Kit” offering will bring more attention to the Marketplace, allowing the customer to explore other energy efficiency equipment and learn more about other PSEG Long Island Programs.

Please note, historically, eligible PSEG Long Island residential customers were allotted one HEA per account. In 2024, and continuing in to 2025, the program rules were adjusted to allow two HEAs per account. The increase in allowable assessments is a result of the ever-changing market. The Home Performance team wants to ensure that all customers can receive an updated HEA to maximize their interaction with the program, and learn about the newer technologies, like Whole House Cold Climate Air Source Heat Pumps, and rebate offerings.

2.3.4.1. Notable Changes

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.

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. As mentioned above, due to the pause of National Grid's Residential Weatherization programs, PSEG Long Island is permitted to include natural gas customers until National Grid's relaunch of its weatherization program.

New in 2025, contractors will be eligible for weatherization incentives. As New York State leans in to emphasizing heat pump and weatherization solutions, PSEG Long Island wants to promote weatherization to engage more weatherization contractors and stimulate growth in that segment. Contractors will receive a $150 contractor incentive for market rate weatherization only projects and $250 for income eligible weatherization only projects. Please note, contractors who install both heat pumps and weatherization receive a $500 "combination project" incentive.

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 any company(s) 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.

2.3.4.2. 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 2024, all projects required pre-approval. This practice will continue in the 2025 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 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 2024, 11 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.

2.3.4.3. Target Market

The Home Performance 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.

It is estimated that 5,000 HEAs and 1,430 Home Performance projects will be completed in the 2025 program year.

PSEG Long Island intends to offer the 2025 program in keeping with prior years, except for the program modifications made in 2022 to support the partnership with National Grid.

2.3.4.4. Measures and Incentives

A list of measures that are offered in the Home Performance program is included in **Table 2-17** and **Table 2-18**.

Table 2-17. PSEG Long Island Home Performance-Eligible Measures List

<table>
<tr><th colspan="2">Eligible Measure</th><th>Minimum Efficiency Requirements</th></tr>
<tr><td colspan="2">Duct Sealing</td><td>UL 181B mastic or tape; use of duct tape is disallowed</td></tr>
<tr><td colspan="2">Duct Insulation</td><td>Installed in accordance with all applicable state and local codes</td></tr>
<tr><td rowspan="2">Building Shell</td><td>Insulation (attic, wall, floor, band joist, basement, crawl space)</td><td>Must be accompanied by blower door assisted air sealing per BPI standards</td></tr>
<tr><td>Air Sealing</td><td>Blower door assisted per BPI standards</td></tr>
<tr><td colspan="2">Windows</td><td>Installed with Whole House Heat Pump, Insulation, and Air Sealing</td></tr>
</table>

Table 2-18. Home Performance: List of Measures

Measure	2025 Planned Units	Measure Incentives	Measure Rebates
Windows - Market	12	-	$3,000
Windows – LMI	7	-	$4,500
LMI Projects	900	$250	$6,250
Market Projects – Non-Gas Customers	360	$150	$1,000
Market Projects – Gas Customers	170	-	$150

2.3.4.5. Outreach

The HEA 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 Home Performance team will work with Home Performance Partners to expand their customer reach by supporting them through workforce development efforts, as referenced in the Home Comfort Outreach section and the training language within this Outreach section, and increased marketing for this segment. Eligible Home Performance Partners will have the opportunity to participate in a marketing 50/50 “cost-share” that supports both the Partners expansion and the Program benefits. The marketing materials will include the PSEG Long Island logo, as well as the program offerings. Partners will work closely with the Home Performance Program Manager to develop the marketing materials, as well as lean on guidance from the PSEG Long Island Marketing Team to ensure all materials are program compliant. There is also an application that the Partner must complete and submit to the Home Performance Program Manager. To support New York State’s weatherization goals and the growth of the installer pool, it is important that PSEG Long Island takes an active role with all facets of Partner engagement.

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.

The Home Performance Program subject matter experts at PSEG Long Island host in-person and virtual open-house meetings and webinars, providing a platform for Home Performance Partners to learn about important program components, such as a deep dive on envelope measures, customer financing, and application submittals. Home Performance focused trainings have demonstrated a high level of Partner engagement and ensure Partners have the necessary tools to reach and engage customers. In-Person and Virtual methods will continue to be available to allow all Partners to remain engaged with the Home Performance Program.

2.3.4.6. Business Case

Home Performance has a SCT benefit-to-cost ratio of 0.72 and RIM benefit-to-cost ratio of 1.77. A list of the value streams considered in the BCA is detailed in **Figure 2-6** and **Table 2-19.**

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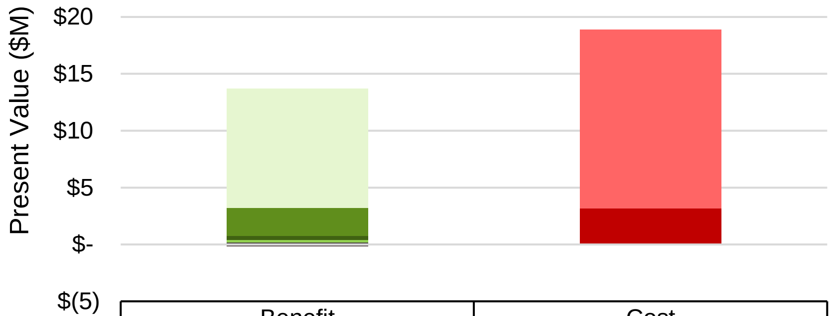
Figure 2-6. Home Performance Present Value Benefits and Costs of SCT



	Benefit	Cost
Fuel Switching Benefits	10.50	-
Net Avoided SO2 and NOx	0.000131	-
Net Avoided CO2	2.46	-
Avoided Distribution Capacity Infrastructure	0.33	-
Avoided Transmission Capacity Infrastructure	0.23	-
Avoided Energy (LBMP)	(0.16)	-
Avoided Generation Capacity Cost (AGCC)	0.20	-
Participant DER Cost	-	15.71
Program Administration Costs	-	3.17
Total	13.55	18.88

Table 2-19. 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.	10.50	
2	**Net Avoided SO_2 and NOx**	Reduced SO_2 and NOx from reduced energy consumption.	0.000131	
3	**Net Avoided CO_2**	Reduced carbon emissions from reduced energy consumption and beneficial electrification.	2.46	
4	**Avoided Distribution Capacity Infrastructure**	Based on demand savings and marginal distribution capacity cost.	0.33	
5	**Avoided Transmission Capacity Infrastructure**	Based on demand savings and marginal transmission capacity cost.	0.23	

#	Value Stream	Calculation Methodology	Benefits (NPV, $M)	Costs (NPV, $M)
6	**Avoided Energy (LBMP)**	Energy savings based on both on-peak and off-peak periods.	(0.16)	
7	**Avoided Generation Capacity Cost (AGCC)**	Based on demand savings and marginal capacity cost.	0.20	
8	**Participant DER Cost**	Includes cost of incremental equipment and installation.		15.71
9	**Program Administration Costs**	Includes contractors fee, labor, evaluation, and advertising costs.		3.17
	Total Benefits		**13.55**	
	Total Costs			**18.88**
	SCT Ratio		**0.72**	

2.3.5. All Electric Homes

The All Electric Homes program is not being proposed for continuance in 2025. This determination is based on participation trends since program inception and the impacts stemming from forthcoming changes to codes and standards.

Since program inception in 2021, 8 projects have been completed.

PSEG Long Island Customers can still achieve whole home electrification through participation in other PSEG Long Island Energy Efficiency Programs.

2.3.6. Multifamily Program

The Multifamily Program launched in October 2020 for New Construction buildings. In 2021, the program expanded to allow Existing Building customers. From program inception, the Multifamily Program was developed to provide developers and building owners with a streamlined application to promote in-unit and common area lighting, heating and cooling equipment, in-unit appliances, and other common area prescriptive style measures like compressors and variable frequency drives.

Over time, as heat pumps have gained more attention the focus of the Multifamily program has shifted accordingly. The Multifamily Program, beginning in 2024 and through 2025, has taken a more “Custom” style program approach. The Program promotes Air Source Heat Pumps, Geothermal Heat Pumps, and Variable Refrigerant Flow (VRF) Heat Pumps that serve either Common Area spaces or In-Unit spaces. The Program also promotes in-unit Energy Star Heat Pump Water Heaters to maximize electrification opportunities and weatherization. Common Area Heat Pumps are rebated on a $/MMBtu basis, in alignment with the Custom program offering. In-Unit Heat Pumps are rebated on a $/Dwelling basis.

The New York Statewide Clean Heat Calculator Tool is utilized to calculate savings for all In-Unit and Common Area space heating heat pumps.

The plan for the 2025 Program Year, looks similar to the 2024 Program Year. It is expected that Common Area and In-Unit Heat Pumps will be the largest drivers in the Multifamily Program. Based on historical and current Multifamily pipeline data, In-Unit Heat Pumps are projected to account for about 80% of the heat pumps (approximately 1,516 heat pump units) installed in the program with the remaining 20% associated with Common Area Heat Pumps (approximately 379 heat pump units). New in the 2025 Program Year, there is a Multifamily "Dwelling Unit" goal of 2,000 Multifamily residential units to be served by heat pumps. Please note, the overall heat pump dwelling unit between the Residential and Multifamily offerings is 5,330, with Multifamily accounting for 2,000 of those dwelling units.

2.3.6.1. Notable Changes

In 2024, to better serve Multifamily building owners and developers and emphasize heat pumps, PSEG Long Island updated the Multifamily application to focus on In-Unit and Common Area heat pumps and In-Unit Energy Star Heat Pump Water Heaters.

In 2024 and going in to 2025, promotion of weatherization in existing Multifamily buildings will also be prioritized.

The New York Statewide Clean Heat Calculator Tool will continue to be utilized for all In-Unit and Common Area space heating heat pumps. All Weatherization measures will be processed utilizing the Custom Program.

2.3.6.2. 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.

2.3.6.3. Target Market

The Multifamily program is offered to developers and building owners who install efficient equipment in low-rise or high-rise multifamily buildings consisting of five or more units.

2.3.6.4. Measures and Incentives

A list of measures that are offered in the Multifamily program is included in **Table 2-20**.

Table 2-20. Multifamily Program: List of Measures

Measure	Measure Rebates
In-Unit ASHP & VRF	$2,728,048
Common Area ASHP & VRF	$682,012
In-Unit HPWH	$300,000
Other (Lighting & Appliances*)	$990,017
Multifamily Existing Building Weatherization (Dwellings)	$55,046

*Please note, appliances in the above table indicate in-unit lighting and appliances that will be completed in 2025. In 2024, in-unit appliances and lighting rebates were discontinued.

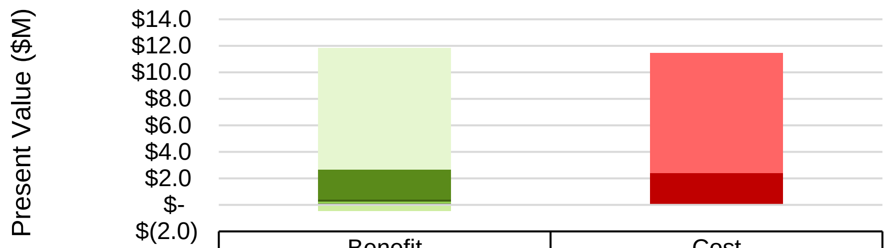
2.3.6.5. Outreach

The CEP engages with Multifamily developers and building owners by working with PSEG Long Island Major Account Consultants (MACs) 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).

2.3.6.6. Business Case

The Multifamily program has a SCT benefit-to-cost ratio of 0.99 and RIM benefit-to-cost ratio of 1.47. A list of the value streams considered in the BCA is detailed in **Figure 2-7** and **Table 2-21**.

Figure 2-7. Multifamily Program Present Value Benefits and Costs



	Benefit	Cost
Fuel Switching Benefits	9.17	-
Net Avoided SO2 and NOx	0.000080	-
Net Avoided CO2	2.26	-
Avoided Distribution Capacity Infrastructure	0.15	-
Avoided Transmission Capacity Infrastructure	0.16	-
Avoided Energy (LBMP)	(0.47)	-
Avoided Generation Capacity Cost (AGCC)	0.10	-
Participant DER Cost	-	9.05
Program Administration Costs	-	2.42
Total	11.37	11.47

Table 2-21. 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.	9.17	
2	**Net Avoided SO_2 and NOx**	Reduced SO_2 and NOx from reduced energy consumption.	0.000080	
3	**Net Avoided CO_2**	Reduced carbon emissions from reduced energy consumption and beneficial electrification.	2.26	
4	**Avoided Distribution Capacity Infrastructure**	Based on demand savings and marginal distribution capacity cost.	0.15	
5	**Avoided Transmission Capacity Infrastructure**	Based on demand savings and marginal transmission capacity cost.	0.16	
6	**Avoided Energy (LBMP)**	Energy savings based on both on-peak and off-peak periods.	(0.47)	

#	Value Stream	Calculation Methodology	Benefits (NPV, $M)	Costs (NPV, $M)
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.		9.05
9	**Program Administration Costs**	Includes contractors fee, labor, evaluation, and advertising costs.		2.42
	Total Benefits		**11.37**	
	Total Costs			**11.47**
	SCT Ratio		**0.99**	

2.3.7. Commercial Efficiency Program

PSEG Long Island's Commercial Efficiency Program (CEP) offers eligible nonresidential customers rebates for a number of Energy Efficiency (EE) and Beneficial Electrification (BE) measures and engineering services. The rebates are intended to offset installation and engineering costs. The CEP strives to deliver a positive customer experience through the diverse portfolio of measures and rebates. The CEP also provides participating partners with equipment training, program education, and other tools to deliver a first-class participation experience for the customer.

The PSEG Long Island's CEP provides customer rebates for the following EE measures:

- Lighting
    - Indoor Lighting
        - Performance Based
        - Prescriptive (Fast Track)
    - Outdoor Lighting
- Custom Heat Pump & Weatherization
    - Whole Building Heat Pumps
    - Geothermal & Geothermal VRF
    - Air to Water Heat Pumps
    - Weatherization
    - Energy Recovery Ventilators & Heat Recovery Ventilators
- Custom and Custom Retrofit

    - Any custom energy saving measures, Chillers, Chiller Optimization, Data Centers, Measurement and Verification (M&V), Whole Building Analysis, etc.
- HVAC
    - Performance Based
    - Partial Building Cold Climate Air Source Heat Pumps
- Geothermal – (Moved to custom in 2025)
- Standard Application
    - Variable Frequency Drives
    - Compressed Air
    - Elevator Modernization
- Refrigeration
- Water Heating and Conservation
- Commercial Weatherization
    - Duct Sealing
    - Air Sealing
    - Envelope Insulation
    - Air Curtains
    - Pipe Insulation
- Beneficial Electrification
    - Forklifts
- Technical Assistance (TA) Program:
    - LEED Certification and Points
    - Energy Star Labeled Buildings
    - Energy Engineering Study
    - Whole Building (Energy Modeling)

Please note, all Custom Heat Pump projects are processed utilizing the New York State Clean Heat Tool. The shift to the Clean Heat Tool allows the program to align with the New York State Joint Utilities and also promote a seamless experience for contractors who participate in other utility Custom Heat Pump Programs. The New York Clean Heat Tool allows CEP to rebate whole building heat pump systems, geothermal and geothermal VRF systems, Weatherization/Heat Pump projects, and ERVs and HRVs.

2.3.7.1. Notable Changes

In 2024, the below changes were made to the Commercial Efficiency Program:

- Expansion of the Prime Efficiency Partner (PEP) program to include all CEP program partners including HVAC, refrigeration, and compressed air technologies.
- Transition of the Geothermal offering to the Custom Program
- Launch of the Partial Building Heat Pumps offering in the HVAC Application
  - Eligibility criteria aligns with NEEP
- Launch of the CEP Assessment Lead Initiative
  - Customers receive an assessment and may request contact information for three PEPs
    - Partners are selected at random using an excel based tool

Please note, as lighting will be phased out after 2025, in 2024 and 2025 the CEP will emphasize and promote lighting to ensure the market is saturated before discontinuation of the measure.

2.3.7.2. Program Delivery

The CEP participation is driven through partnerships with installation contractors, or partners. Customers may opt to participate as a self-install, but participation is primarily driven through partners. The CEP collaborates with 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. All trainings and open-house meetings are available in-person or virtual. This practice will continue in 2025 to ensure all Lead Partners can remain engaged with the Commercial Efficiency Program.

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 April 2024 PSEG Long Island hosted its first ever “Heat Pump Technologies and Solutions Conference” geared towards manufacturers, distributors, and installers. There were 15 different breakout sessions focusing on topics like Air Source Heat Pumps 101 to the New York State Clean Heating Tool. Over 550 attendees participated in the informative event. The next “EE” conference is scheduled to be held on November 7, 2024. The “EE” conference will feature sessions on Electric Vehicles, Heat Pumps, and Lighting. As lighting will be phased out after 2025, it is important to engage all potential lighting customers to maximize this technology before it is no longer in the EE Portfolio.

PSEG Long Island continues to promote contractors who have been certified PEPs. The PEPs drive small business participation, making it paramount to vet and promote these contractors. The introduction of the PEP 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 (as needed), and meet the strict program requirements. The launch of the PEP 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 $5,000. The Fast Track Program is unique in that only PEPs may participate, and pre-approvals and pre-inspections are not required. Allowing PEPs 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.

2.3.7.3. Target Market

All nonresidential customers in the PSEG Long Island service territory.

2.3.7.4. Measures and Incentives

The CEP utilizes a mix of prescriptive, performance-based, and Custom savings methodologies. For all measures, rebates are set per market conditions, and may adjust during the year as the market changes. **Table 2-22** details programs within CEP.

Table 2-22. Commercial Efficiency Program: List of Programs

Measure	Total Measure Rebates
Custom - Heat Pumps	$2,151,753
Custom - All Else (i.e., UV Lighting, Refrigeration, Controls, AHU, etc.)	$1,330,981
CEP Lighting All (CPL, FT, OL)	$12,807,057
CEP HVAC - AC	$110,915
CEP HVAC - Heat Pumps	$177,464
CEP Motors, VFD's, & Air Compressors	$133,098
CEP Refrigeration	$22,183
TA Program	$200,000
CEP Electric Equipment (Non-Road EV's – Fork Lift)	$44,366
CEP Weatherization (Air Sealing, Insulation (Attic, Walls), Air Curtain, Duct Sealing, Pipe Insulation)	$22,183
CEP All Else (Commercial Hot Water, Pool Equipment, Elevators)	-

2.3.7.5. 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.

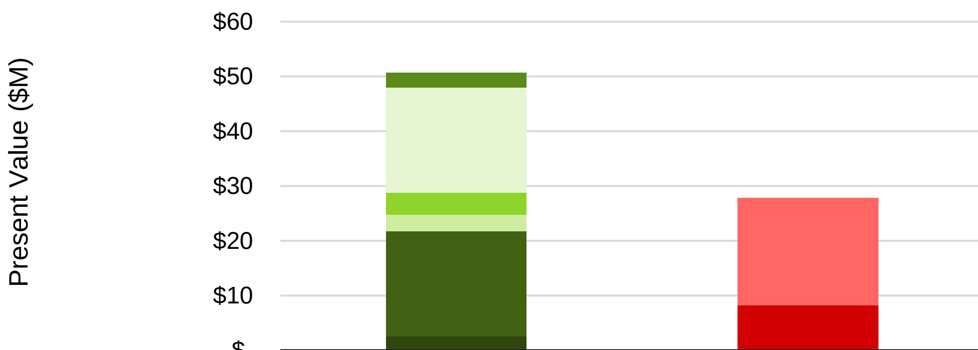
New in 2023, PSEG Long Island launched a new outreach initiative called “Counter Days”. Counter Days bring together PSEG Long Island ECs and PEPs who are also distributors. The EC coordinates with the PEP in advance and delivers program banners to the distributor’s location and spends the day at the 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. The Outreach Team has also launched opportunities for Lead Partners and PEPs to receive individual training at lighting distributor locations.

In 2024, as lighting will be phased out after 2025, the CEP launched a “Look Up” Lighting campaign to encourage Commercial customers to take advantage lighting rebates, while still available. The “Look Up” campaign is as simple as it sounds, customers should “Look Up” to see what is in their ceiling and take action to upgrade their old inefficient lighting to save energy and money.

2.3.7.6. Business Case

The Commercial programs have a SCT benefit-to-cost ratio of 1.82 and RIM benefit-to-cost ratio of 0.64. A list of the value streams considered in the societal benefit-cost analysis is detailed in **Figure 2-8** and **Table 2-23**.

Figure 2-8. Commercial Efficiency Program Value Present Value Benefits and Costs of SCT



	Benefit	Cost
Fuel Switching Benefits	2.69	-
Net Avoided SO2 and NOx	0.000023	-
Net Avoided CO2	19.27	-
Avoided Distribution Capacity Infrastructure	3.99	-
Avoided Transmission Capacity Infrastructure	3.10	-
Avoided Energy (LBMP)	19.20	-
Avoided Generation Capacity Cost (AGCC)	2.48	-
Participant DER Cost	-	19.60
Program Administration Costs	-	8.23
Total	50.74	27.83

Table 2-23. 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.	2.69	
2	**Net Avoided SO_2 and NOx**	Reduced SO_2 and NOx from reduced energy consumption.	0.000023	
3	**Net Avoided CO_2**	Reduced carbon emissions from reduced energy consumption and beneficial electrification.	19.27	
4	**Avoided Distribution Capacity Infrastructure**	Based on demand savings and marginal distribution capacity cost.	3.99	
5	**Avoided Transmission Capacity Infrastructure**	Based on demand savings and marginal transmission capacity cost.	3.10	
6	**Avoided Energy (LBMP)**	Energy savings based on both on-peak and off-peak periods.	19.20	
7	**Avoided Generation Capacity Cost (AGCC)**	Based on demand savings and marginal capacity cost.	2.48	
8	**Participant DER Cost**	Includes cost of incremental equipment and installation.		19.60
9	**Program Administration Costs**	Includes contractors fee, labor, evaluation, and advertising costs.		8.23
	Total Benefits		**50.74**	
	Total Costs			**27.83**
	SCT Ratio		**1.82**	

2.3.8. Dynamic Load Management Programs

LIPA introduced the Dynamic Load Management (DLM) Tariff program 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 DLM Tariff consists of a Direct Load Control (DLC) program and a Demand Response (DR) program. The program is effective during the capability period, which is May 1-September 30.

The DLC Program known as the “Smart Savers Program” allows PSEG Long Island to control central air conditioning systems via Wi-Fi enabled Smart Thermostats during peak electric use 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 program, which emulates the New York Independent System Operator's Emergency DR and Special Case Resource programs. The Demand Response Program compensates customers who agree to reduce their electric load by a specified amount during peak electric use periods (May-Sept) typically but not exclusively through deployment of onsite Stand-by Emergency Generation or Energy Storage Systems. Under this tariff, medium-to-large size commercial customers or residential and small commercial customers through an Aggregator must 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.

2.3.8.1. Notable Changes

Effective June 1, 2019, LIPA modified the DLM Tariff to allow Net Energy Metered customer to be eligible to participate in the Demand Response program which effectively permitted 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.

2.3.8.2. Program Delivery

To implement the DLM Tariffs, PSEG Long Island contracted with service provider EnergyHub which includes Program Services: Program management, marketing, training, enrollment support, dispatch support, and reporting.

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. Advanced Metering Infrastructure (AMI) 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.

2.3.8.3. 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 2-24** shows the enrollment activity as of January 1, 2023.

Table 2-24. DLM Tariff Results as of January 1, 2024

Program	2023 Customers	2023 Measured Load Reduction (MW)	2023 Curtailment Events	Curtailment Events (2016-2023)
Smart Savers Program*	49,273	36.37***	1	27
CSRP/DLRP**	925	25.2****	7	44

**Enrollment is cumulative*
***Customers enrolled for the 2023 season, May 1 – September 30*
****Number of devices multiplied by the average load shed per device*
*****Contracted load relief*

In 2023, most customers enrolled in CSRP were also enrolled in DLRP. The MW reductions shown in **Table 2-25** reflects the performance from both programs combined and are not additive.

Table 2-25. DLM Tariff 5 Year Forecast[42]

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

[42] *All DLM payments are collected through the Power Supply Charge and therefore do not impact the operating budget.*

Associated Capacity (MW)	2024	2025	2026	2027	2028
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**

2.3.9. Home Energy Management (HEM) - Behavioral Initiative

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.

2.3.9.1. 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 Profile Survey function. The main reasons for the increase in customers are as follows:

- Given the shift to TOD for most residential customers, providing customers with reports on energy usage and time is an additional opportunity to educate them about saving 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.

2.3.9.2. 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). Additionally, this program 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. A majority of customers surveyed (HER Customer Satisfaction Survey Q4, 2023) resulted in overall satisfaction with Home Energy Reports (62%) and indicated that the reports provided useful energy saving tips (59%). Report content promoting existing EE programs have resulted in an uplift of activity in the REAP and Home Performance programs. Additionally, this program has fostered the development of marketplace solutions such as smart thermostats and participation in the Smart Savers demand response program, which will induce deeper clean energy penetration and leverage greater private investments in such efforts.

Outcomes undergoing evaluation by third party evaluator include:

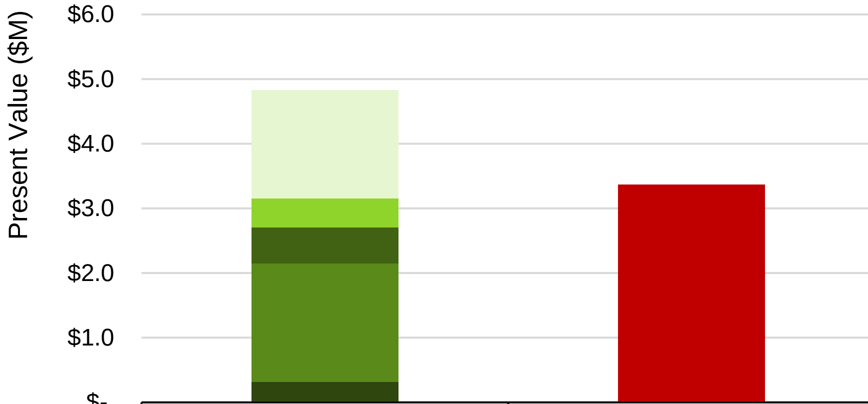
- Customer bill savings
- Reduction in GHGs
- Clean energy penetration including increased use of renewable and low carbon sources,
- Demand and capacity reductions
- Greater private sector investment in clean energy solutions,
- Customer satisfaction

This HEM program enables residential customers to realize cost-effective verifiable EE savings confirmed by a third party evaluator, while also increasing awareness and adoption of applicable programs, products, and services, and increases customer satisfaction.

2.3.9.3. Business Case

HEM has a SCT benefit-to-cost ratio of 1.43. A list of the value streams considered in the societal benefit-cost analysis is detailed in **Figure 2-9** and **Table 2-26**.

Figure 2-9. Home Energy Management Value Present Value Benefits and Costs of SCT



	Benefit	Cost
Net Avoided CO2	1.68	-
Avoided Distribution Capacity Infrastructure	0.44	-
Avoided Transmission Capacity Infrastructure	0.56	-
Avoided Energy (LBMP)	1.83	-
Avoided Generation Capacity Cost (AGCC)	0.32	-
Program Administration Costs	-	3.37
Total	4.83	3.37

Table 2-26. Home Energy Management 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.	1.68	
4	**Avoided Distribution Capacity Infrastructure**	Based on demand savings and marginal distribution capacity cost.	0.44	
5	**Avoided Transmission Capacity Infrastructure**	Based on demand savings and marginal transmission capacity cost.	0.56	

#	Value Stream	Calculation Methodology	Benefits (NPV, $M)	Costs (NPV, $M)
6	**Avoided Energy (LBMP)**	Energy savings based on both on-peak and off-peak periods.	1.83	
7	**Avoided Generation Capacity Cost (AGCC)**	Based on demand savings and marginal capacity cost.	0.32	
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.		3.37
	Total Benefits		**4.83**	
	Total Costs			**3.37**
	SCT Ratio		**1.43**	

2.4. Energy Efficiency and Heat Pumps Five-Year Plan

The commercial and residential sector energy consumption, especially in regard to space heating, contribute significantly to GHG emissions in New York State. In an effort to meet the state mandated goals that aim to target GHG reduction, PSEG Long Island has developed a five-year plan towards the achievement of 2030 CLCPA goals. This section details the plan as it relates to the energy efficiency and heat pump CLCPA goals. Given the interdependencies of these goals and the program overlap, the below plan interlaces energy efficiency and heat pump efforts to present a cohesive 2030 strategy.

2.4.1. Current State

2025 Targets

2025 HP Goal	30,000 installs
2025 HP Achievement (As of Q1 2024)	>30,000 installs
2025 EE Goal	7.85 TBtu
2025 EE Achievement (As of Q1 2024)	6.68 TBtu

Heat Pump Targets

The basis for 2025 goal was the 2020 annual EEDR Plan for that year's heat pump categories, with a reasonable growth rate across categories. Consequently, PSEG Long Island was determined to have a 2025 heat pump goal of 30,000 installs. As of Q1 2024, PSEG Long Island has exceeded the 2025 heat pump target of 30,000 units installed.

Energy Efficiency Targets

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. As of Q1 2024, PSEG Long Island has achieved 6.68 TBtu of the 2025 energy efficiency goal, or 85%. Given current savings target for 2025, PSEG Long Island is projected to achieve 96% of the 2025 goal. The gap that remains between projected achievement and the 2025 goal is not budgetary issue, but rather customer adoption rate hurdles and market saturation congestion. Additionally, the loss of high efficacy, cost-effective lighting savings further adds to the likelihood of a savings gap.

2.4.2. Future State

2030 Targets

2030 HP Goal	67,769 dwellings
2030 HP Achievement (As of Q1 2024)	8,276 dwellings

Heat Pump Targets

In 2022, Governor Hochul announced a plan for 2 million electrified or electrification-ready homes with heat pumps to provide electric heating and cooling and paired with energy efficiency[43]. In an effort to more accurately represent this refined heat pump goal towards electrifying homes, the unit of measurement for this goal has shifting from installs to dwellings. To determine individual utility potential relative to the goal, the NYSERDA BEEM was developed by Cadmus to assess potential statewide heat pump achievement. According to the outputs of the NYSERDA BEEM, the PSEG Long Island 2030 heat pump target is 67,796 dwellings. LIPA requested that PSEG Long Island develop a proposed approach to reaching the 2030 heat pump goal. Accordingly, Demand Side Analytics (DSA) was enlisted by PSEG Long Island to develop a potential tool to estimate potential heat pump dwelling adoption through 2030 by year, sector, and technology. See 2026-2030 Potential Tool sub-section for full detail.

[43] Energy Efficiency and Building Decarbonization - NYSERDA

Energy Efficiency Targets

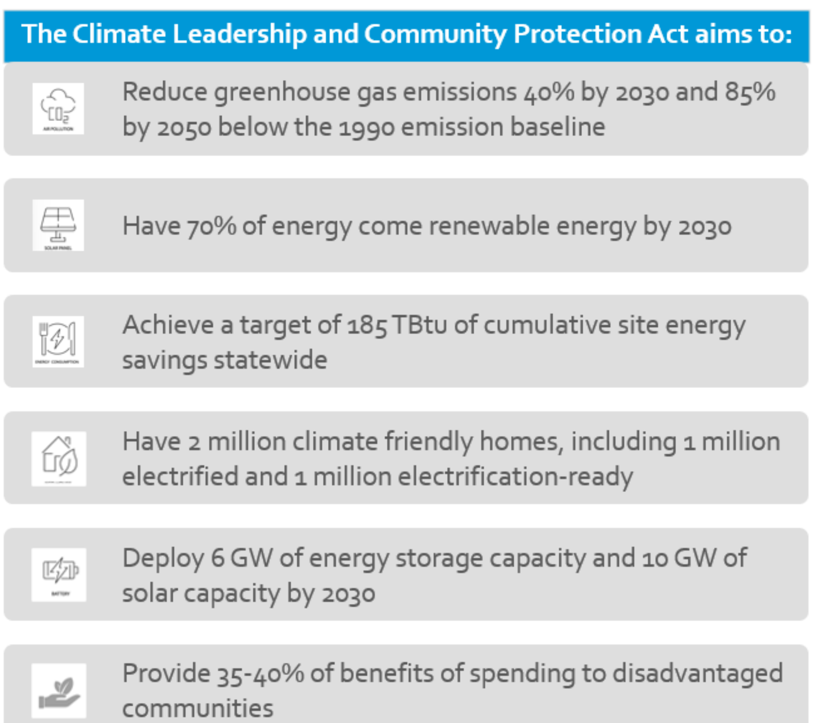
There is not currently a 2030 target for energy efficiency. When looking towards the future of energy efficiency, 2026 will serve as a ramp up year for program design as the energy efficiency program experiences major measure shifts. The NE:NY order, new building codes and the EISA standards remove a substantial amount of high-yield low-cost efficiency measures starting in 2026. Future Energy Efficiency efforts will consequently focus on low-yield, high-cost measure to capture energy efficiency savings. Further details of this programmatic shift are detailed in the *Background to Tool Development* section.

2.4.2.1. 2026 – 2030 Potential Tool

Background to Tool Development

New York has several sweeping and ambitious statewide clean energy goals. In 2018, the NE:NY white paper was published. In 2019, the CLCPA was signed into law. Through the CLCPA, New York is doubling down on its efforts to create a clean, resilient, and equitable energy grid, as reflected in the process outlined in **Figure 2-10**. In 2022, Governor Hochul announced a plan for 2 million electrified or electrification-ready homes by 2030.

Figure 2-10. Process to Develop 2026-2030 Plan



Meanwhile, the US Department of Energy is proposing more stringent codes and standards. The codes change baselines and, thus, reduce the traditional energy efficiency opportunities available to programs, specifically lighting. This will require program administrators to be nimble regarding eligible products to ensure the portfolio continues to push market transformation. As a result, PSEG Long Island is focused on expanding renewable energy resources, further electrifying and decarbonizing their system, reducing GHG emissions, and escalating programs in disadvantaged and low-income communities.

PSEG Long Island was the first utility in the state to shift its primary performance metric to MMBtu to align with these New York targets. This new performance metric created opportunities to pursue Beneficial Electrification measures and electrify end uses via air source heat pumps, heat pump water heaters, and heat pump pool heaters. PSEG Long Island has been a leader in expanding beneficial electrification measures in its service area. Heat pumps have become a central element of the decarbonization strategies. The underlying logic is simple. As the electric grid supply becomes cleaner, shifting from reliance on fossil fuels (oil, propane, natural gas, wood) for heating to highly efficient electric heat pumps reduce overall energy use and substantially reduces GHG emissions.

The policy changes have significant implications for the PSEG Long Island programs, including:

- A shift away from traditional energy efficiency toward heat pump technology and beneficial electrification.
- An emphasis on interventions that lead to long-term reductions or eliminate electricity, natural gas, and fossil fuel usage (strategic measures)
- An emphasis on DACs

The NENY order, new building codes, and new federal standards remove many measures that historically have been among the cost-effective, including:

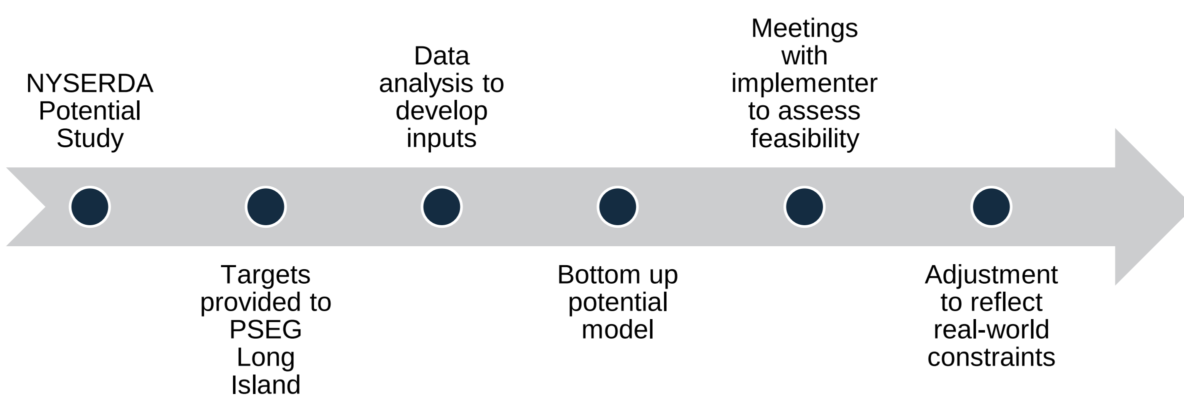
- **Residential lighting.** Federal standards require LEDs for nearly all residential light fixtures, starting in 2024.
- **Non-residential lighting.** Federal standards require LEDs for nearly all non-residential light fixtures, starting in 2026.
- **Behavioral reports**. New York will no longer fund behavioral programs via the public good surcharge, since the measures rely on behavior, do not deliver long-term reductions absent continued intervention, and have been deemed non-strategic.
- **Residential appliances**, including refrigerators, plug loads, clothes washers, clothes dryers, and dishwashers. This is due to upcoming shifts in federal appliance standards that will make energy-efficient options mandatory, starting in 2026.

- **New construction heat pumps and heat pump water heaters.** New York building codes will require all new construction to install heat pumps for space heating and water heating, starting with residential sites in 2026 and non-residential ones in 2028.

The mix of energy efficiency measures being deprecated, mostly in 2026, accounted for approximately 53% (~520 MMBtu) of the 2023 portfolio ex post energy savings. Programs will have to adapt, make sizeable changes, and ramp up in key areas to meet goals. The expected changes include a much higher volume of heat pump retrofits, an increase in the volume of heat pump water heaters, and more extensive weatherization programs. The new direction amounts to a paradigm shift and will require much more than adjustments to existing programs. The workforce to support the level of building electrification and weatherization envisioned will need to be developed. In addition, PSEG Long Island will need to establish networks with a wider range of contractors. The transition will require rapid experimentation to learn what works and what does not and to understand the impact of incentives on customer energy efficiency and decarbonization technology choices.

PSEG Long Island undertook a variety of activities to understand the available opportunities for energy efficiency and building electrification and plan a strategic path. **Figure 2-11** provides an overview of the process, which started with NYSERDA's BEEM potential and targets for heat pump provided to PSEG Long Island.

Figure 2-11. Process to Develop 2026-2030 Plan



While the NYSERDA study was useful, PSEG Long Island needed additional detail to develop a meaningful strategic plan. Potential studies are inherently "bottom-up" exercises. The magnitude of resources that can be acquired is driven by numerous factors, including customer preferences, financial incentive levels, building characteristics, targeting, and codes and standards. In recent years, PSEG Long Island commissioned a series of analyses to inform the planning around electrification and low-income and DAC targeting, including:

- Linking property data to all PSEG Long Island residential customers, allowing the use of property information and electric usage patterns and the development of metrics around energy use intensity and electric energy burden.

- Disaggregating electric cooling and heating loads from base loads, thus helping identify highly weather-sensitive customers.
- Collaborating with other utilities to quantify the impact of incentives on heat pump adoptions – a heat pump price elasticity. This particular element is critical for answering two questions critical to planning: By how much customer do incentives influence the adoption of heat pumps? And, what budget is needed to meet the goals?
- Estimating customer adoption propensities for heat pump, heat pump water heating, HVAC measures, and lighting energy efficiency. The propensities use data about customers who have and have not adopted a technology – e.g., heat pumps, electric vehicles – and energy use patterns and property characteristics to quantify the likelihood of adoption and identify early versus late adopters.

In addition, PSEG Long Island had empirical data from the programs it had been administering regarding costs and energy savings by measure in it is service territory. Thus, the decision was made to develop a bottom-up potential model to produce supply curves and understand the budgets needed to meet critical goals.

Model Overview

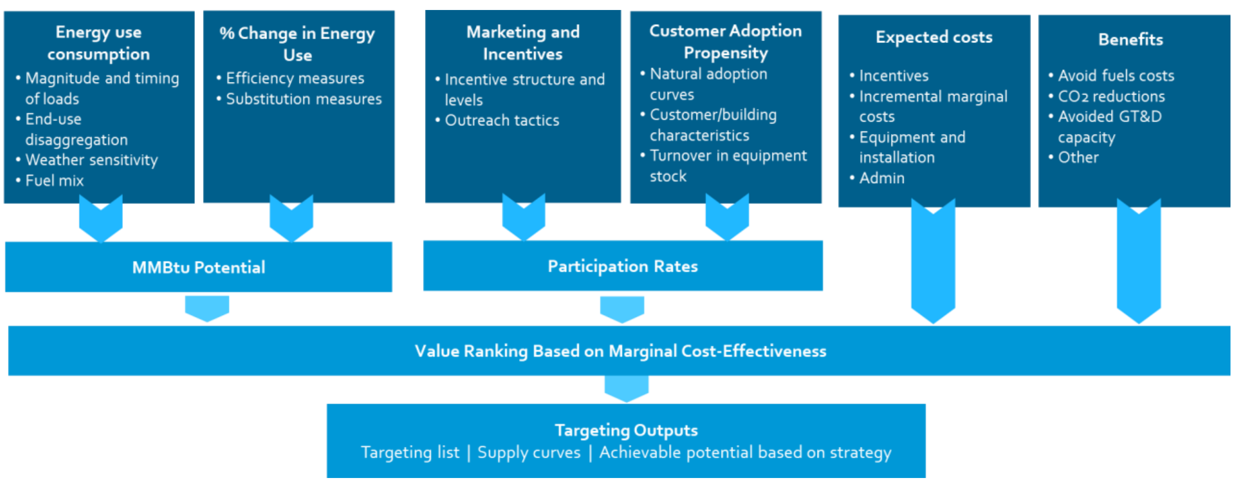
A well-designed potential study is useful for answering several important policy and design questions, including:

- How much untapped potential remains?
- Is it cost-effective to expand existing programs and measures?
- Are there specific customer segments that are more or less cost-effective than others? And how do the expected savings vary based by measure for different types of customers?
- What are the most cost-effective measures available?
- What is the supply cost curve for energy efficiency, beneficial electrification, and weatherization measures?
- What are the incentive levels and budget needed to meet targets?

Potential studies are inherently “bottom-up” exercises. The magnitude of resources that can be acquired is driven by numerous factors, including customer preferences, financial incentive levels, building characteristics, budget levels, targeting strategies, and codes and standards. While energy efficiency and beneficial potential have a very significant technology component, the achievable potential is fundamentally driven by behavior, particularly customer preferences, participation rates, incentive levels, and funding decisions. They also have real-world limitations. Within a model, it is possible to target and optimize with exact precision, which is far more difficult to do in a real-world setting. The models also can ignore scaling constraints, such as supply chain limitations or the need to develop a workforce with the qualifications and skills to weatherize homes and install electric and water equipment. Moreover, it can lead to sharp turns that are difficult to enact in real life.

Figure 2-12 provides a conceptual overview of the building blocks. A key step is disaggregating the energy by building type, customer segment, and end-use. This was done for a total of over 4,000 combinations of location, building/customer segment, and DACs. PSEG Long Island used a combination of AMI data disaggregation and NREL residential and commercial end-use load shapes by building type specific to Nassau and Suffolk counties. For each location and customer segment, the whole building electricity use was disaggregated into 35 end-uses for residential customers and eight end-uses for commercial and industrial customers. This provided a detailed picture of how energy was used, where it was used, and by whom it was used. Notably, the NREL data also includes information regarding fossil fuel use. The efficiency, beneficial electrification, and weatherization measures were mapped to the end uses. For each measure, we also extracted the energy savings and costs from the program databases and combined them with square footage data to develop costs and savings that were scaled with square footage where appropriate. The data on energy use and the change in energy use provided an estimate of technical potential.

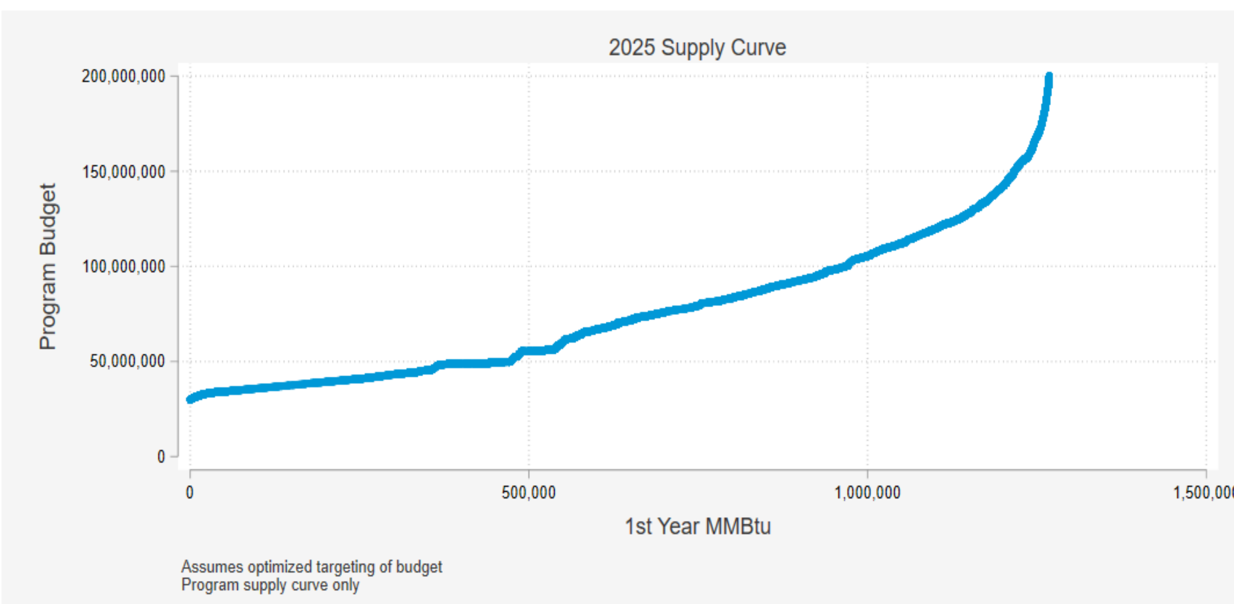
Figure 2-12. Conceptual Overview of Potential Model



However, customer preferences, incentive levels, and turnover in equipment stock play a critical role. Thus, the second main branch was factoring in the impact of customer adoption propensities, equipment stock turnovers, and the effect of incentive levels on adoption curves. Fundamentally, incentives lower the customer-facing price and accelerate the adoption over and above the natural adoption curve. They also help nascent technologies survive in the marketplace until they mature and cost lower due to economies of scale. PSEG Long Island's consultant, DSA, had estimated the relationship between discounts/incentives and adoption for heat pumps – a metric known as the price elasticity. They also conducted other studies outside of Long Island to determine price elasticity for smart thermostats, LED lighting, heat pump water heaters, and battery storage. The price elasticities were used to estimate the impact of different levels of incentives on small, medium, and large energy efficiency and beneficial electrification customer investment decisions. At this point, the model incorporated data on the expected benefits and costs associated with the change in energy use. More specifically, the model estimated the cost-effectiveness of each measure and customer segment combination for each year in the planning period. The goal was to develop resource cost curves that stack different measures and building/customer segments based on their cost-effectiveness and untapped resource potential.

Figure 2-13 illustrates the supply curve for a single year. The figure only includes results from program-based resources. The approach allows PSEG Long Island to understand not only the potential, but also the budget needed to attain specific energy-saving amounts and which measures and building/customer segments need to be prioritized to meet the goals. The supply curves allow policy makers and planners better understand the right scale for different types of resources, allows for comparison with other alternatives, and helps optimize the resource mix. One of the key challenges is representing supply curves in a meaningful manner since they can get too granular to be practical. Thus, we sometimes aggregate to a higher level and lose some dimensionality (e.g., location) to make the supply curves interpretable and interactive.

Figure 2-13. Supply Curve Example



As noted earlier, it is difficult to target and optimize with exact precision in a real-world setting. In practice, there are competing priorities such as heat pump goals, or ensuring funding also reaches low-income customers and DACs. Thus, the model has three built-in options:

- **Maximize the portfolio MMBtu.** This setting picks measures and customer segments as long as the portfolio benefit-cost ratio is above one (using the societal cost test). It maximizes the cost-effective total MMBtu via programs, but also assumes no funding constraints and assumes optimal targeting is possible.
- **Apply Budget Limits by Year.** This allows the user to apply budget limits by year on an aggregate level. The reality is that budgets are not unlimited. However, the model still selects the mix of measures and customer segments based entirely on cost-effectiveness.
- **Apply Detailed Budget Limits.** This option allows the user to set budget limits by year for eight categories, defined by combinations of energy efficiency and electrification, residential and non-residential, and low-income and DACs versus standard customers. It effectively allows the user to place added importance on specific types of customers or measures and to avoid sharp changes. The downside is that it deviates more and more from an optimal targeting approach and requires manual iteration. It leads to more spending for the same amount of energy savings due to the multiple goals and constraints. The detailed budget limit option was used in developing the plan due to the spending targets for DACs and the emphasis on electrifying heating.

In addition, the model incorporated constraints to avoid growth in measures scheduled for deprecation, such as behavioral reports or lighting. Finally, upon discussions with the implementation vendor, additional adjustments were incorporated to reflect reality. If left unconstrained, the model opted for sharp increases in heat pump water heaters and weatherization in 2026, immediately after the removal of lighting measures, behavioral programs, and new construction heat pumps from the program options menu. The adjustment allowed for a more gradual ramp-up of weatherization and heat pump water heaters to reflect the need to develop a workforce that can weatherize homes and install heat pump water heaters at scale.

Model Outputs

The focus of the results discussion is provided on a sector and technology level, rather than a program level. The model outputs focus on dwelling penetration, associated MMBtu savings, and the supporting budgets at this sector and technology level from 2026 to 2030. These outputs reflect the potential achievement given assumptions and impacts outlined in the previous section.

Table 2-27 summarizes the potential dwellings achievement, by sector and technology type from 2026- 2030. In terms of heat pump goal achievement, the Multifamily (MF) heat pumps estimate 11,354 dwellings and Residential (Res) heat pumps excluding heat pump water heaters (HPWH) estimate 33,351 dwellings, as highlighted in the table below. This projection, coupled with the projected achievement through 2025 of 16,372[44], results in a potential 2030 achievement of 61,077 dwellings. The PSEG Long Island Team expects codes and standards to contribute 10,000 – 12,000 additional dwellings, resulting in overall achievement of the 2030 heat pump goal.

Table 2-27. 2030 Potential Model Outputs for Dwellings by Technology and Sector

Sector	Technology	2026 (dwellings)	2027 (dwellings)	2028 (dwellings)	2029 (dwellings)	2030 (dwellings)	Total (dwellings)
Comm	Weatherization	119	178	238	297	356	1,188
MF	Heat Pumps	2,017	2,205	2,809	2,314	2,009	11,354
Comm	Other (Ref, HVAC Controls, Cooking)	2,765	2,783	2,170	2,253	1,985	11,956
Res	Weatherization	5,001	7,266	9,530	11,794	14,058	47,649
Res	Heat Pumps Water Heaters	4,232	6,929	9,626	13,075	13,932	47,794
Res	Heat Pumps (excluding HPWH)	4,650	6,066	6,927	7,535	8,173	33,351
Res	Controls	28,899	29,870	29,937	29,726	29,100	147,532
Res	Other	16,302	17,742	16,441	16,621	16,370	83,476
	Total	**63,985**	**73,039**	**77,678**	**83,615**	**85,983**	**384,300**

High level potential achievement for energy savings and dwellings by sector and technology type were determined by the tool and the associated yearly budget to support the associated achievement produced. **Table 2-28** summarizes the potential EE savings (on a MMBtu basis), by sector and technology type from 2026- 2030.

[44] Achievement through 2023 = 7,442 dwellings. 2024 target = 3,600 dwellings. 2025 target = 5,330 dwellings. Summation = 16,372 dwellings

Table 2-28. 2030 Potential Model Outputs for Energy Savings by Technology and Sector

Sector	Technology	2026 (MMBtu)	2027 (MMBtu)	2028 (MMBtu)	2029 (MMBtu)	2030 (MMBtu)
Comm	Weatherization	7,005	9,656	13,674	20,650	31,643
MF	Heat Pumps	27,966	35,520	45,958	52,252	58,115
Comm	Other (Ref, HVAC Controls, Cooking)	134,782	142,474	142,147	144,084	126,002
Res	Weatherization	98,545	141,172	185,102	192,893	223,989
Res	Heat Pumps Water Heaters	40,913	61,157	95,488	129,847	136,677
Res	Heat Pumps (excluding HPWH)	344,019	443,400	531,142	611,983	688,375
Res	Controls	16,236	16,992	17,514	17,988	18,381
Res	Other	89,720	99,274	104,532	111,198	116,575
Total		**759,186**	**949,645**	**1,135,557**	**1,280,895**	**1,399,757**

Table 2-29 summarizes the associated O&M budget corresponding to the potential EE savings (on a MMBtu basis) and dwellings achievement quoted above in **Table 2-27** and **Table 2-28**, by sector and technology type from 2026 - 2030. As a result, significant budget increases would be needed each year through 2030, to meet the 2030 heat pump dwelling goal.

Table 2-29. O&M Budget through 2030 by Sector and Technology

Sector	Technology	2026 ($M)	2027 ($M)	2028 ($M)	2029 ($M)	2030 ($M)
Comm	Weatherization	0.40	0.57	0.78	1.08	1.51
MF	Heat Pumps	2.30	2.77	3.56	3.69	3.75
Comm	Other (Ref, HVAC Controls, Cooking)	13.44	14.32	13.88	13.86	11.34
Res	Weatherization	11.11	15.70	20.45	20.79	23.87
Res	Heat Pumps Water Heaters	2.76	4.31	6.23	8.40	9.13
Res	Heat Pumps (excluding HPWH)	35.47	46.01	52.63	56.98	61.61
Res	Controls	3.25	3.38	3.41	3.38	3.31
Res	Other	28.54	31.53	30.46	31.31	31.62
	Administration	12.28	12.53	12.78	12.78	12.78
	Total	**109.55**	**131.12**	**144.18**	**152.27**	**158.92**

2.4.3. Future State Program Design

Heat Pumps

In an effort to increase heat pump adoption across the PSEG Long Island service area, LIPA solicited a study[45] to identify the current barriers to adoption and to issue recommendations to address the barriers identified. From this study the following barriers to heat pump adoption were identified:

- Targeting and engaging the most likely or motivated customer
- Purchasing: Design, Financing and Purchase processes create friction and risk for customers generally

Contractors - Contractor pool, contractor motivation to sell heat pumps and distributor engagement to stock heat pumps are limited and/or insufficient to program scale-up needs. Existing program requires "paperwork" payments to motivate contractors - a review and streamlining of contractor processes is well warranted to support scale up to address the barriers identified and increase heat pump adoption rates, PSEG Long Island was tasked with developing three heat pump centric initiatives:

1. Heat Pump Customer Economics Tool
2. Customer Outreach and Marketing Plan (COMP)
3. Supply Chain Development Project Implementation Plan (PIP)

These three initiatives are detailed in the following sections. Deployment of these initiatives began in 2024, but the efforts of these initiatives will continue to develop, and transform based on initiative performance and feedback. The purpose of these initiatives is to drive heat pump adoption towards the 2030 goal, however these initiative will focus on implementation through 2026 with the intent to revisit and revise efforts based on where the initiatives are successful and where they require improvement.

Heat Pump Customer Economics Tool

The deployment of the tool provides both customer and contractors the ability to analyze the economics of converting the customer's domestic heating source to heat pump technology using customer-specified inputs. A snapshot of the tool interface is shown in **Figure 2-14**. While the results are not expected to be to the level of detail that a contractor would use for sizing a proposed system for installation, they should be directionally indicative as to

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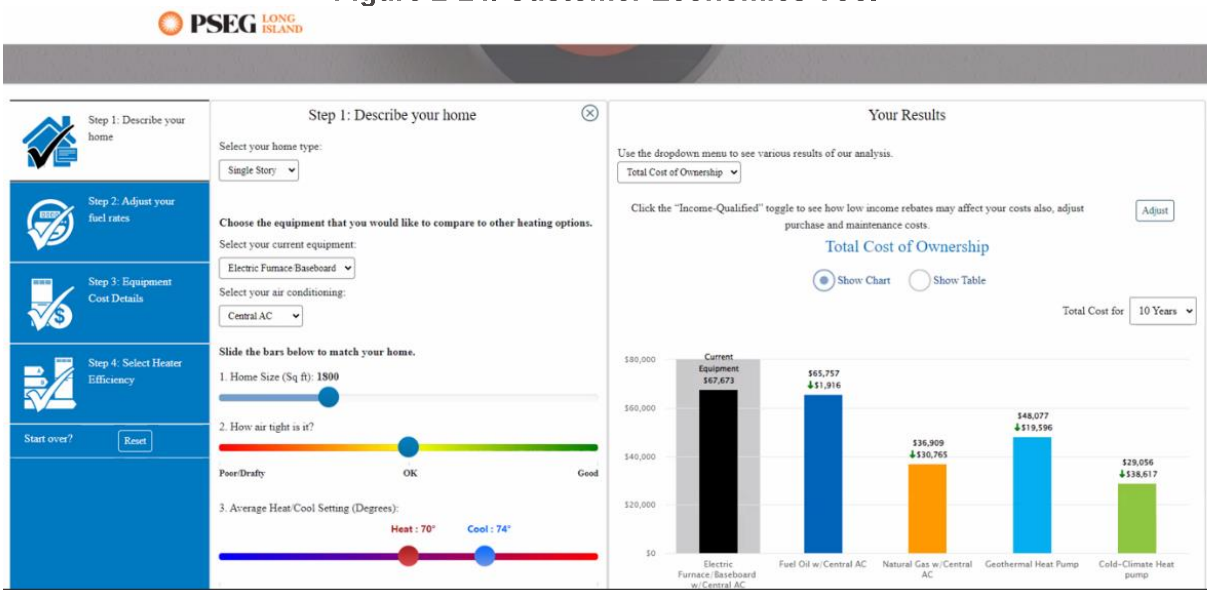
[45] UCS-44 Next Level Heat Pump Deployment-Barriers and Actions

whether the conversion will have a positive payback and a rough estimation of how long before that occurs. The overall intent of the tool to increase customer and contractor understanding of heat pump technologies to further drive heat pump adoption.

Figure 2-14. Customer Economics Tool



Customer Outreach and Marketing Plan (COMP)

The Heat Pump Marketing Plan is a marketing plan and advertising campaign to build awareness, education, and demand for Heat Pumps to PSEG Long Island customers. The goal of the plan is to increase customer engagement and interest in whole house cold climate heat pumps. The plan has a targeted focus on capturing multifamily dwelling units of low to moderate-income customers in DACs and converting these dwellings to heat pumps as their primary heat source. The 2024 marketing plan leverages key learnings from 2023, but also expands and refines strategies to ensure a more targeted, impactful, and successful marketing approach. The key strategies to increase customer outreach are as follows:

- Propensity data integration
- LMI audience focus
- Content sponsorships
- Direct mail optimization
- Reincorporating successful channels

The marketing plan utilizes Sightline to enrich data, segment performance analyses, develop the propensity model and customer-level target scoring, and for targeted direct outreach support and campaign performance tracking. In 2024, ICF will incorporate propensity data to ensure there is a one-to-one connection between marketing efforts and qualified audiences. This approach will be coupled with Cable TV and a content sponsorship package based on previous year's learnings to create a well-rounded campaign with strong direct response results.

The marketing and outreach approach detailed above will continue to be implemented and monitored through 2025. Improvement to customer engagement will be iterative and leverage lessons learned for improvement 2026 through 2030.

Supply Chain Development Project Implementation Plan (PIP)

The Supply Chain Development PIP was developed to expand interest and engagement across the existing heat pump supply chain supporting Long Island as well as grow the pool of contractors, distributors, and manufacturers operating on Long Island in both size and capability. This is achieved through engagement, new and enhanced incentives, program streamlining, and direct support with a programmatic emphasis on whole home heat pump solutions. PSEG Long Island developed a plan based around targeted initiatives:

1. Streamlining existing program
2. Design and implementation of a midstream program
3. Enhancement and streamlining of incentives
4. Training and capacity development of installers/contractors
5. Case studies of successful implementation on Long Island

This program will result in investigating potential for streamlined enrollment process for contractors as well as streamlined paperwork and handoffs in the application, inspection, and payment process. Additionally, TRC continues to emphasize whole-home heat pump projects through applications, webinars, and program announcements. At the end of 2024, the Contractor Recognition Program should result in an active and scheduled dialogue between PSEG Long Island and other New York State utilities, a coordinated effort between PSEG Long Island, NYSERDA, and other institutions focused on the labor pool supporting heat pumps, and a coordinated network of Long Island focused heat pump industry stakeholders who are focused on achieving Long Island's share of New York State heat pump goals. Furthermore, success of the Program will produce easier and simpler means by which interested customers can locate high quality and local heat pump contractors as well as new technology and potentially new program delivery offerings being rolled out in the 2025 program plan year.

The overall approach to this effort will be iterative, with plans to revisit planning upon execution of these efforts to inform 2026 planning. Approach will be continuously adjusted based on program success, gaps, technological innovation, and as new information becomes available.

Energy Efficiency

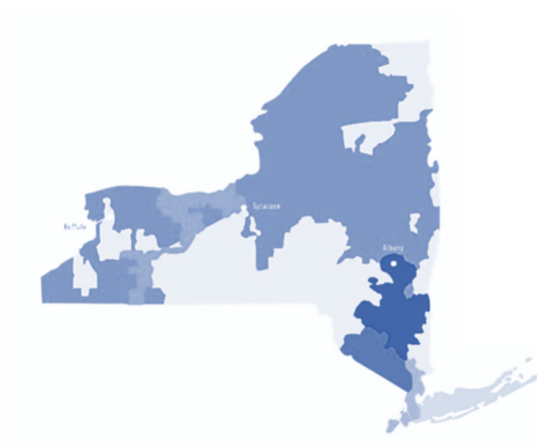
Existing Energy Efficiency programs will change and transform over time with shifting responsibilities and dissolution of programs. In 2024 and 2025, the team will evaluate which Energy Efficiency programs to retain and focus on identifying the best delivery methods for the future measure offering. This may result in dissolution of some programs or the consolidation of programs into a solo Energy Efficiency program. Energy Efficiency offerings will pursue a new path starting in 2026, to align with state policy objectives. In an effort to keep up with the changing energy landscape and combat loss of major energy savings measures, weatherization will become a key component of energy efficiency saving achievement through 2030. The PSEG Long Island team will review 2025 weatherization performance to assess future planning.

2.4.4. Gaps Analysis

Utility Benchmarking

A benchmarking analysis was conducted to identify programs and activities that other New York State utilities are utilizing to increase heat pump adoption and energy efficiency savings. The benchmarking analysis reviewed the detailed Energy Efficiency and Beneficial Electrification filings across New York utilities. **Figure 2-15** displays the utilities assess and the level of filings reviewed.

Figure 2-15. New York State Utility Mapping



Utility	EE-BE Proposal	LMI Specific Proposal
KEDNY/KEDLI	✓	
Niagara Mohawk Power Corporation d/b/a National Grid	✓	✓
Central Hudson G&E Corporation	✓	
Con Edison	✓	✓
Orange and Rockland Utilities	✓	✓
NYSEG RG&E	✓	
NFGDC	✓	

The approaches detailed across utilities for energy efficiency and heat pump adoption through 2030 remained fairly consistent. There was a clear and persistent focus on weatherization across the utilities. Utilities plan to leverage contractor engagement and networks to increase weatherization adoption. For larger utilities, filings disaggregated programs into sector-specific programs (i.e., Residential Weatherization Program, C&I Weatherization Program, Multifamily Weatherization Program). To meet heat pump adoption goals across all sectors, utilities continue to focus on Clean Heat Program implementation and expansion. Larger utilities pursuing large-scale adoption via Midstream program design and contractor engagement were identified as critical to meeting adoption targets.

New York State utility filings continued to focus on DAC/LMI adoption rate via targeted advertising and marketing through 2030. Utility marketing collaborated with market participants, stakeholders, and community partners to identify potential program design improvements. Most utility plans detailed improving digital and language accessibility, collecting stakeholder feedback, and marketing efforts to recruit contractors who work within underrepresented DACs. Additionally, utilities focused on enhancing the webpage customer journey to streamline customer experience and engagement.

The benchmarking analysis reviewed the detailed Energy Efficiency and Beneficial Electrification filings across New York utilities to identify high-impact gaps within PSEG Long Island's current and planned offerings to develop potential solutions to integrate into the five-year plan. Overall, PSEG Long Island plans closely echo the approaches outlined by peer utilities, and no major gaps were identified. The lack of gaps is also likely attributable to the heat pump barriers study conducted, as mentioned at the beginning of this section, which resulted in PSEG Long Island addressing major heat pump barriers to adoption in current and future planning. Potential middle-impact planning gaps are identified as:

- **Weatherization Offering Paths**: PSEG Long Island's current plans through 2030 reflect a strong emphasis on the implementation and incentivization of weatherization measures. Comparison to other utility offerings identify avenues for diversification of weatherization offerings:
    1. **Midstream Offerings**: Some New York State utilities envision midstream incentive offerings to market-rate residential single-family homeowners who install various forms of insulation and air sealing. The goal of the retail midstream program would be to empower customers to conduct smaller scale/DIY weatherization/envelop measures. Self-install measures like pipe insulation could be offered through an in-store midstream delivery model. Potential to provide these midstream incentives to big box retailers, like Home Depot and Lowe's, as well as smaller stores, for pass-through price reductions. Additionally, Midstream offerings could increase general awareness of the benefits of energy efficient products via traditional marketing, such as in-store POP materials and ad placements. PSEG Long Island is assessing the potential to engage in midstream weatherization offerings in future years, depending on program and budget availability.

2. **Home Energy Kits:** Providing home energy kits to residential customers via mail that include weatherization measures such as spray foam, weatherstripping, or caulking could provide a cost effective way to further residential weatherization efforts. PSEG Long Island is assessing the potential savings and economic feasibility of such an implementation.

- **Workforce Development**: There is currently a gap between weatherization jobs and skilled workers[46]. Developing a qualified workforce is critical to capture the weatherization savings potential at the scale proposed in the potential model. PSEG Long Island may leverage planned collaboration with NYSERDA and the Long Island Clean Energy Hub in the heat pump space to include weatherization. PSEG Long Island will consider developing relevant training, weatherization promotion, workforce development initiatives, and other opportunities to improve the workforce on Long Island.

External Gaps

While gaps between PSEG Long Island planning and other New York State utilities remain minimal, external gaps between potential and actual CLCPA goal achievement are substantial:

- **Heat Pump technological gap**: In the PSEG Long Island service territory, more than 50% of space heating is hydronic radiant baseboard heating, for which there is not an easily available direct replacement currently commercially available. The emergence of a commercially available direct bolt-on replacement technology would close some of the customer adoption gaps that exist due to technological constraints.
- **Funding gap:** The BEEM and the DSA potential model outputs demonstrate that a higher level of funding will be needed in order to achieve the goals, in alignment with the State of the State Address. The projected funding requirement significantly exceeds the funding that is currently deployed. Funding gaps will prevent adequate achievement of the CLCPA goals.

[46] Weatherization Assistance Program (WAP) Workforce Needs Analysis

3. Transportation Electrification

2024 Utility 2.0 Plan Annual Filing, Energy Efficiency Plan, and Five-Year Plans

3. Transportation Electrification

The transportation sector is the second biggest contributor of GHG emissions in New York State.[47] To achieve the GHG reduction goals by 2050 set forth in the New York State Climate Act, the state has committed to:

- All new passenger cars sold in New York State to be zero-emissions by 2035[48]
- Electrifying the state's light-duty fleet and 100% of school buses by 2035[49]
- All new medium and heavy-duty vehicles (MHDV) sales to be zero-emissions by 2045[50]

These transportation electrification targets are supported by initiatives that encourage wider adoption of electric vehicles (EVs). One key initiative is the statewide EV Make-Ready Program, which incentivizes greater deployment of electric vehicle supply equipment (EVSE) such as Level 2 and Direct Current Fast Chargers (DCFC) 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 directly contribute to Transportation Electrification. In 2024, PSEG Long Island's Transportation Electrification Strategic Initiatives include the EV Make-Ready Program, Fleet Make-Ready Program, and the EV Program. The EV Make-Ready Program supports New York State goals to achieve a 40% reduction in GHG emissions from 1990 levels by 2030 and the New York State Department of Environmental Conservation's (DEC) Advanced Clean Car II (ACC) regulation which requires all new passenger vehicle sales to be zero-emissions by 2035 in New York State.[51] The Fleet Make-Ready Program supports the goals of electrifying 100% of electric school buses by 2035[52] and the DEC's Advanced Clean Trucks (ACT) regulation for all new

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

[48] New York Advanced Clean Car Regulation. DEC Announces Adoption of Advanced Clean Cars II Rule for New Passenger Cars and Light-Duty Truck Sales - NYSERDA

[49] 2022 New York State of the State. 2022StateoftheStateBook.pdf (ny.gov)

[50] New York Advanced Clean Trucks Regulation. Governor Hochul Announces Adoption of Regulation to Transition to Zero-Emission Trucks | Governor Kathy Hochul (ny.gov)

[51] New York Advanced Clean Car Regulation. DEC Announces Adoption of Advanced Clean Cars II Rule for New Passenger Cars and Light-Duty Truck Sales - NYSERDA

[52] 2022 New York State of the State. 2022StateoftheStateBook.pdf (ny.gov)

MHDV sales to be zero-emission by 2045.[53] PSEG Long Island's ongoing EV Program also promotes adoption of EVs and is consistent with the ACC II Regulation, which requires all new passenger vehicle sales to be zero-emissions by 2035 in New York State.

Table 3-1 below details how PSEG Long Island's Transportation Electrification programs contribute to targets set forth in various New York State policies and/or regulations.

Table 3-1. New York State EV Goals

Year	Policy / Regulation		EV Make-Ready Program	Fleet Make-Ready Program	EV Program
2025	ACC	35% of Light-Duty Vehicle (LDV) sales are ZEVs	✓	✓	✓
2027	2022-2023 State Budget	All new school bus fleet purchases are ZEVs		✓	
2035	ACC	100% of LDV sales are ZEVs	✓	✓	✓
	2022-2023 State Budget	100% of school bus fleet are ZEVs		✓	
2045	ACT	100% of MHDV sales are ZEVs		✓	

PSEG Long Island targets supporting the adoption of 178,500 light-duty EVs on Long Island which derives from the 2025 statewide light-duty EV goals of 850,000 EVs through various transportation electrification initiatives. As of Q1 2024, there are around 55,000 EVs on Long Island, which is approximately 30% of 178,500 EVs.

Chapter Contents

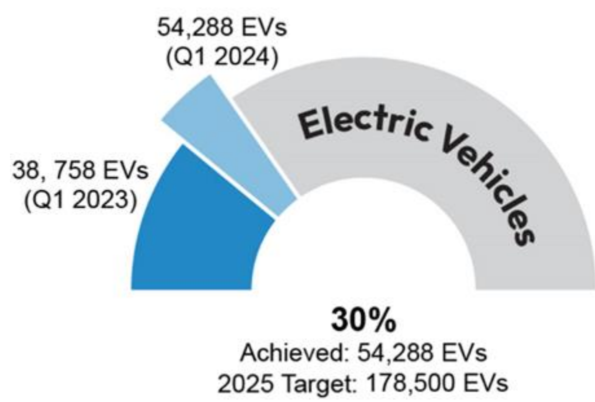
[53] New York Advanced Clean Trucks Regulation. Governor Hochul Announces Adoption of Regulation to Transition to Zero-Emission Trucks | Governor Kathy Hochul (ny.gov)

Project Name	2024 Status	2025 Status	Page #
Residential Charger Rebate	Active	Active	127
DCFC Incentive Program	Active	Active	129
EV Phase-in Rate	Approved	Active	129
Suffolk County Bus Make-Ready Pilot	Active	Active	135

3.1. 2025 Goal Achievement

New York State has previously committed to 850,000 electric LDVs by 2025, which is now superseded by ACC and ACT. PSEG Long Island' various transportation initiatives will continue to support Long Island's share (178,500 EVs) of the overall New York State goal of 850,000 light duty vehicles registered and on the road by the end of 2025, as well as ACC and ACT. As of Q1 2024, there are approximately 55,000 EVs on Long Island (**Figure 3-1**).

Figure 3-1. Transportation Electrification 2025 Target Achievement



Utility 2.0 Transportation Electrification program updates are detailed in **Section 3.2**. The Transportation Electrification Five-Year Plan is detailed in **Section 3.3**.

3.2. Transportation Electrification Utility 2.0 Initiatives and Programs

3.2.1. Make-Ready Program

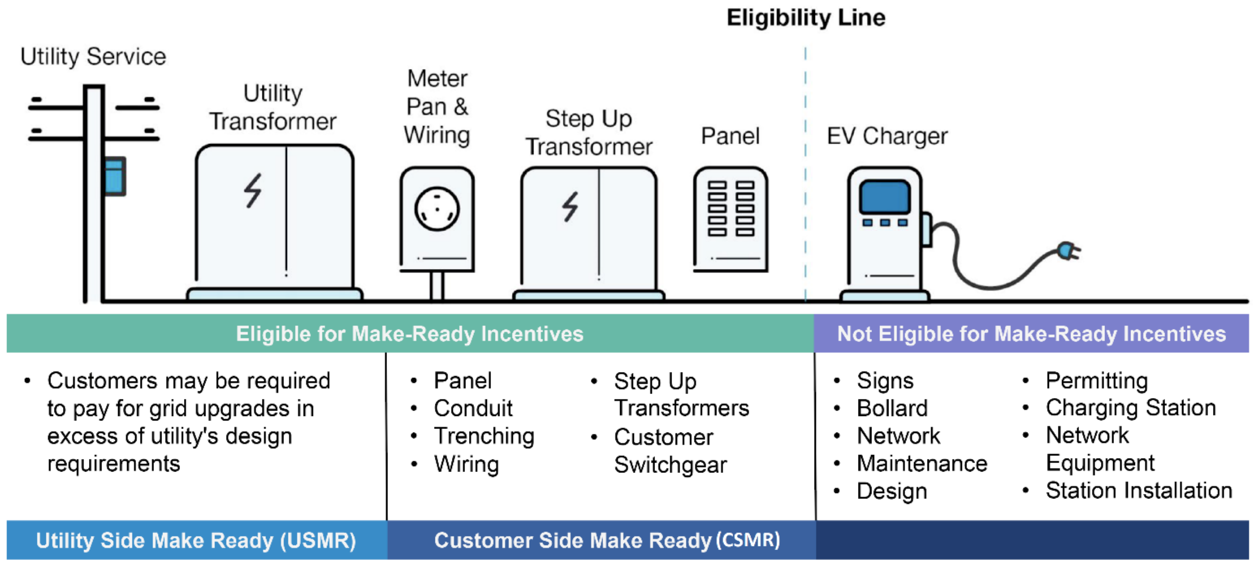
2024 Status	Active
2025 Status	Active
Start Year	2021
Funding Approved Through	2027

Description and Justification	The EV Make-Ready Program was initially proposed in 2020 to support and accelerate EV adoption on Long Island. This Program was expanded and renamed as the Make-Ready Program and now covers three programs and services: (1) the EV Make-Ready Program; (2) the Fleet Advisory Service; and (3) the approved Fleet Make-Ready Program. PSEG Long Island plans to update the **EV Make-Ready Program** to increase both the Level 2 and DCFC charger target and extend this program to support make-ready infrastructure through 2030. The **Fleet Advisory Service** was approved in 2022 and officially launched in Q3 2023. The approved **Fleet Make-Ready Program** will provide Utility-Side and Customer-Side Make-Ready incentives to eligible fleet customers operating LDVs and MHDVs on Long Island and will be launched in Q3 2024. The scope and funding for the Make-Ready Program is revaluated in this filing to support additional chargers and the expanded scope to enable fleet electrification on Long Island.

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 3-2**).

Figure 3-2. 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.[54] The Make-Ready Order recommends that major electric utilities provide financial contributions for Make-Ready infrastructure to accelerate EVSE deployment, in turn enabling a 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

[54] 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.

compared to L2 charging, thus avoiding having to recover a significant amount of operating expenses (for rebates for CSMR infrastructure) from ratepayers in the year incurred. 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.[55] The Whitepaper recommended a higher program budget, updated plug projections for both L2 and DCFC, and added flexibility on the 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 Transportation Electrification Team's experience in administrating the program, PSEG Long Island extended the program by two years (to 2027); slightly decreased the L2 port target; updated the assumed make-ready costs; updated the incentive tiers to be 100%, 75%, and 50%; and updated the program budget to reflect these changes.

As part of the five-year planning effort, PSEG Long Island reevaluated this program and proposes to further expand the EV Make-Ready Program by extending the Program timeline and drastically increasing port targets to meet EV infrastructure needs. Program updates are primarily informed by DPS's Recommendation Letter that suggested PSEG Long Island to increase port counts to support the growing number of EVs. Program updates were additionally informed by the LDV Forecast that utilized historical data and market trends to develop an annual EV count and subsequent port target to meet EV demand.[56] During the five-year planning process, PSEG Long Island identified a gap in infrastructure support after 2027 to meet port targets informed by both DPS's Recommendation Letter and data from the LDV Forecast. Thus, PSEG Long Island plans to extend the EV Make-Ready Program into 2030 to meet the port target and support the forecasted number of EVs. As a result, PSEG Long Island identified an overall L2 port target that has nearly tripled compared to last year's plan, and an overall DCFC port target that has increased by over 50%.

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 approved Fleet Make-Ready Program. While other New York State utilities have

[55] Review and recommendations regarding the Long Island Power Authority and PSEG Long Island's 2023 Utility 2.0 Plan Annual Update and 2023 Energy Efficiency (EE) Plan, November 1, 2023

[56] Gabel Associates developed this LDV Forecast estimating EV adoption based on market conditions and historical trends in Spring 2024.

similar pilots, this will be the first program designed to serve fleets, which include both LDV and MHDV segments, in New York State. The Fleet Make-Ready Program serves two target markets that would most likely benefit customers in DACs: 1) public fleets which cover local government, public serving, schools & universities (admin & security), and not-for-profit organizations; 2) public transportation (e.g., school buses and transit buses).

The Fleet Make-Ready Program is a separate program offering, parallel to the EV Make-Ready Program under the Make-Ready Program (**Section 3.2.1**). 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. Eligible customers can apply for either program or both programs through the Make-Ready Program application.[57]

The Program design is being developed in the first half of 2024. The program will officially launch in Q3 2024 and provide US-MR and CS-MR incentives[58] to eligible fleet customers. The scope and timeline of this program is further evaluated in the Five-Year Plan.[59] PSEG Long Island may expand the program to provide US-MR support to private fleet customers beginning in 2027 to support private fleet electrification. PSEG Long Island plans on extending the program through 2030 to provide additional charging infrastructure support for both public and private fleets.

Fleet Advisory Service

The Make-Ready Program also includes the Fleet Advisory Service.[60] The Service is available for free to both public and private fleet customers operating within PSEG Long Island's service territory and launched in Q3 2023. Service offerings in this Program include:

1. **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.

In the past year, around 30 organizations have connected with the Team through the Fleet Advisory Service, with the majority being private fleet operators serving public school

[57] More details on Make-Ready Program application are available on the PSEG Long Island website.
[58] The same US-MR and CS-MR definitions apply to both EV Make-Ready Program and Fleet Make-Ready Program.
[59] Future details on the Fleet Make-Ready Program update can be found in the Five-Year Plan.
[60] Additional details on the Fleet Advisory Service can be found in 2022 Utility 2.0 Long Range Plan & Energy Efficiency Plan.

districts, government agencies, or not-for-profits. Additionally, over half of total inquiries were from private fleet operators supporting school districts. Large commercial fleets represent a small share of inquiries. Thus, the Team identified school districts as a key group that require the most support to electrify to date. Fleets often reached out for a walkthrough of the Fleet Advisory Tool and more information on PSEG Long Island's offerings based on their needs. The TE Team uses these opportunities to inform participants of the upcoming Fleet Make-Ready Program, available incentives at the state and federal level, and how to get started with their fleet electrification journey.

Based on the frequently asked questions, the Transportation Electrification Team is also considering developing helpful reference materials such as a one-pager or a playbook for fleet customers to reference following a consultation with the Fleet Advisor. Information included in the reference materials could include interconnection process, typical stages of fleet electrification, and available programs and resources.

The Transportation Electrification Team also hosted a Fleet Roundtable in February 2024 and will host additional Fleet Roundtables to engage with fleet customers and promote the Fleet Advisory Service to encourage and support a broad spectrum of fleet owners on their fleet electrification journeys.

3.2.1.1. 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[61] that informed what policies and trends are influencing the pace at which these vehicle segments will electrify, and their impact on the 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 Q3 2024.

See the scope and schedule updates below for Make-Ready Program.

3.2.1.1.1. Scope Update

Overall, PSEG Long Island is supporting the adoption of 178,500[62] EVs on Long Island through various transportation electrification initiatives.

[61] The MHD Make Ready Study can be found in 2023 Utility 2.0 Plan.

[62] This figure is from NYS's statewide goal (850,000 vehicles) and 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 2023 Utility 2.0 Plan to adjust program targets and extend the program. PSEG Long Island has since reevaluated annual program enrollments and budget requirements based on the previously mentioned DPS Letter, LDV Forecast, and Five-Year Plan. PSEG Long Island proposes to extend the Make-Ready Programs until 2030 and increase both overall L2 and DCFC port targets to support EV adoption.

The EV Make-Ready Program

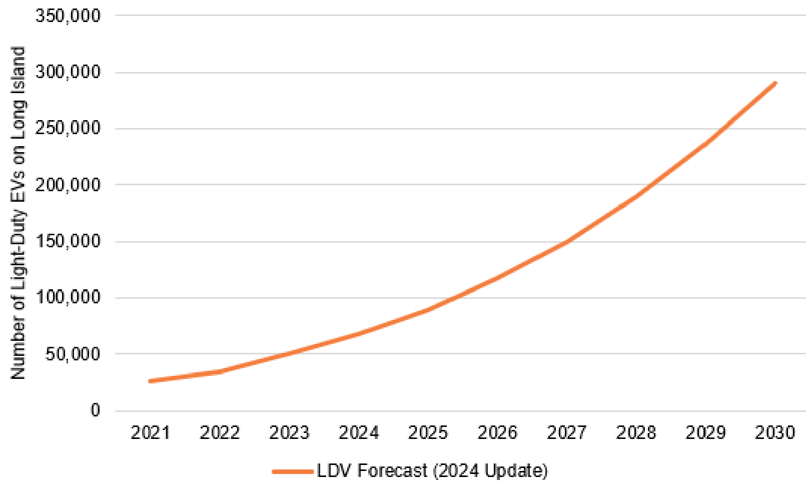
EV Adoption

EV adoption on Long Island has continued to grow since the Team started tracking in 2014. Long Island has some of the highest EV adoption rates in the state with around 55,000 EVs on the road as of Q1 2024.[63] PSEG Long Island uses the number of EVs on the road to forecast what it anticipates EV adoption to look like in future years. Understanding how many EVs will be on the road allows PSEG Long Island to right-size the infrastructure needed, along with understanding how many charging stations are necessary to support EV adoption.

PSEG Long Island works with a third-party consultant to develop this LDV Forecast and update it annually based on market trends (see graph below). In the most recent forecast (2024 Forecast), PSEG Long Island has identified that EV adoption will continue to grow out to 2030 based off of historical trends. [64] As shown in **Figure 3-3**, PSEG Long Island anticipates that by 2030, there will be around 300,000 EVs on the road on Long Island which will represent 13.5% of all LDVs on Long Island.

[63] Long Island's EV penetration grew to 2.6% in January 2024 from 1.6% in 2022. NYS had 1.3% EV penetration in 2022 based on data from Alternative Fuels Data Center.
[64] Gabel Forecast estimated EV adoption based on market conditions and historical trends to develop more accurate port targets.

Figure 3-3. Light-Duty Electric Vehicle Adoption Trends on Long Island



Ports

As shown in **Table 3-2,** PSEG Long Island expects that enrollment in the EV Make-Ready Program will gradually increase over time at a slightly slower pace than originally forecasted. Based on DPS's Recommendation Letter and the LDV Forecast, PSEG Long Island plans to increase overall L2 and DCFC port targets drastically to meet charging infrastructure demand in line with EV adoption rate.[65] During the five-year planning process, PSEG Long Island identified that the EV Make-Ready Program should be extended through 2030 to continue to support EV and public charging demand. PSEG Long Island used the results of its 2024 LD EV Forecast to model the number of Level 2 and DCFC ports needed by 2030, utilizing the EV-Pro Lite tool.[66]

Table 3-2 and **Table 3-3** show the updated total number of ports estimated to be pre-approved[67] and energized, respectively, by year and port type.[68] Overall L2 port target is increased by 9,600 ports to be 13,652 by 2030; overall DCFC port target is increased by 285 ports to be 783 ports by 2030.

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[65] Gabel Forecast estimated EV adoption based on market conditions and historical trends to develop more accurate port targets.
[66] EVI-Pro Lite projects consumer demand for EV charging infrastructure. Some assumptions PSEG Long Island utilized include 77% at-home charging, default values from tool to estimate share of vehicle type (ex. Sedans versus SUVs) and engine type (PHEVs versus EVs), and third-party consultant industry insights.
[67] Pre-approved may also be referred to as "enrolled" or "committed".
[68] 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.

Table 3-2. EV Make-Ready Program Actual and Estimated Pre-Approved Ports by Type (2024 Update)

Port Type	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total[69]
	Actual	*Actual*	*Actual*	*Forecast*	*Forecast*	*Forecast*	*Forecast*	*Forecast*	*Forecast*	*Forecast*	
L2	8	185	540	500	573	1,290	1,863	2,484	3,105	3,105	**13,652**
DCFC	0	108	114	68	82	82	82	82	82	82	**783**
Total	**8**	**293**	**654**	**568**	**655**	**1,372**	**1,945**	**2,566**	**3,187**	**3,187**	**14,435**

The expected number of energized ports as shown in **Table 3-3** is based upon the assumption that L2 projects would take approximately six months on average from committing funds to construction and that DCFC projects would take approximately 15 months. Thus, some of the projects are expected to be completed in 2031.[70]

Table 3-3. EV Make-Ready Program Actual and Estimated Energized Ports by Type (2024 Update)[71,72]

Port Type	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	Total
	Actual	*Actual*	*Actual*	*Forecast*	*Forecast*	*Forecast*	*Forecast*	*Forecast*	*Forecast*	*Forecast*	*Forecast*	
L2	0	81	231	293	789	752	1,433	2,018	2,639	3,105	2,311	**13,652**
DCFC	48	100	10	54	89	92	82	82	82	82	62	**783**
Total	**48**	**181**	**241**	**347**	**878**	**844**	**1,515**	**2,100**	**2,721**	**3,187**	**2,373**	**14,435**

The infrastructure targets were originally developed based on assumptions regarding the amount of infrastructure required to support New York State targets for EV adoption.[73] 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, economic factors (e.g. interest rates) 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

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[69] Table values may not add to total value due to rounding.
[70] All projects that enroll in the EV Make-Ready Program must commit to complete by 2031.
[71] Even though the program is intended to end in 2030, some projects may spillover into 2031.
[72] The 2022 L2 port count was updated from 87 to 81 based on the most up-to-date information in the PSEG-LI Internal EV Make-Ready Program Database as of August 15, 2024, which is reflected in this table. The 2031 L2 port count was also updated due to a previous addition error in the original table and was reduced to 2,311 so that the total number of L2 ports would still be 13,652 (consistent with the pre-approved total port count). Supporting documentation provided on July 1, 2024 will differ slightly from the updated forecast presented here.
[73] 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.

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 cost estimates for L2 are updated in this filing to reflect PSEG Long Island's historical program data. The cost estimates for DCFC are based on the JU's actual project cost data[74] as the PSEG Long Island actual program data for DCFC is limited in certain cost components. **Table 3-4** shows the infrastructure costs based upon PSEG Long Island or JU's actual average project cost data.

Table 3-4. EV Make-Ready Program Infrastructure Costs by Port Type[75] (2024 Update)

Port Type	US-MR	CS-MR	Total
Level 2	$57	$50,715	$50,772
DCFC	$20,008	$357,031	$377,039

To ensure equitable distribution of incentives, PSEG Long Island established incentive caps based on project type shown in **Table 3-5.**

Table 3-5. EV Make-Ready Program Incentive Caps (2024 Update)[76]

Port Type	Number of Plugs	Incentive
DCFC	**4+**	$370,000
	2+	$185,000
Level 2	**3+**	$30,000
	2+	$20,000

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

[74] As outlined in the Midpoint Review.
[75] Assumes 4 Level 2 ports and 4 DCFC ports per project.
[76] See additional detail on PSEG Long Island's website: https://www.psegliny.com/en/saveenergyandmoney/GreenEnergy/EV/MakeReady.

Business Model

PSEG Long Island implements the lease-to-buy model, along with a USMR coverage only option, for all DCFC projects, and the rebate model for all L2 projects.[77]

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 or for private use
- whether it utilizes standard charging port types
- 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 eligibility requirements per incentive tier is shown in **Table 3-6**.

Table 3-6. EV Make-Ready Program Eligibility (2024 Update)

Port Requirement	100% Incentive	75% Incentive	50% Incentive
Minimum 2 Ports for All Incentive Tiers	• DCFC and/or Level 2 Chargers • Universal Plugs • Accepts Universal Payment • Public • Located in a DAC	• DCFC and/or Level 2 Chargers • Universal Plugs and/or NACS Plugs • NACS plugs matched 1 for 1 or less for quantity and power output from Universal plugs • Accepts Universal Payment • Public • Not located in a DAC	• DCFC and/or Level 2 Chargers • Universal Plugs and/or NACS Plugs • NACS plugs not matched 1 for 1 or less for quantity and power output from Universal plugs • Does not accept Universal Payment • Private

[77] Additional details can be found in 2022 Utility 2.0 Long Range Plan & Energy Efficiency, Beneficial Electrification, and Demand Response Plan.

The Fleet Make-Ready Program

The 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 commercial tariff, consisting of any vehicle-type or weight-class. The Program focuses 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 other EVSE.

The program guidelines discussed in the following section is preliminary and may be updated and finalized upon program rollout in Q3 2024.

Projects

The Fleet Make-Ready Program aims to serve two target markets: 1) public fleets which cover local government, public serving, schools & universities, 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 3-7 shows the total number of projects estimated to be enrolled, respectively, by year and project type. These estimates were developed by a third-party consultant based on budget availability.[78] These estimates are not tied to the number of ports enrolled, while it will be tracked through this program.

During the five-year planning process, PSEG Long Island identified the importance of the Fleet Make-Ready Program in supporting fleet electrification efforts. Thus, PSEG Long Island plans on extending the program through 2030 to provide additional infrastructure support for fleets.

PSEG Long Island also recognizes that private fleets are an important customer segment to support and may expand program eligibility to include private fleets starting in 2027. More information on these potential program changes is available in the Five-Year Plan section.

[78] See more details in the MHD Make Ready Study developed by Gabel Associates, which can be found in 2023 Utility 2.0 Plan.

Table 3-7. Fleet Make-Ready Program Estimated Pre-Approved Projects[79]

Project Type	2024	2025	2026	2027	2028	2029	2030	Total
Public Fleets	**4**	**8**	**14**	**26**	**37**	**37**	**37**	**163**
Small/Medium (<1,000 kW)	3	6	11	21	30	30	30	131
Large (>1,000 kW)	1	2	3	5	7	7	7	32
Public Transportation	**4**	**7**	**11**	**12**	**12**	**12**	**12**	**70**
Small/Medium (<1,000 kW)	1	2	3	4	4	4	4	22
Large (>1,000 kW)	3	5	8	8	8	8	8	48
Private Fleets	**0**	**0**	**0**	**26**	**37**	**37**	**37**	**137**
Small/Medium (<1,000 kW)	0	0	0	23	33	33	33	122
Large (>1,000 kW)	0	0	0	3	4	4	4	15
Total	**8**	**15**	**25**	**64**	**86**	**86**	**86**	**370**

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.[80]

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

[79] These estimates are based on projects that may be pre-approved each year. Some projects may require more than a year to be completed. Additionally, the project size will be determined based on nameplate capacity.
[80] 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.

- Applicant must be a fleet operator[81] 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.
- Ride-hailing or car-sharing services are not eligible to participate in this program at this time but would be eligible with the expansion of private fleet project types in 2027.

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. Additionally, eligibility requirements are subject to change upon rollout in Q3 2024.

Infrastructure Costs

The make-ready costs are divided into two categories: US-MR and CS-MR. **Table 3-8** shows the estimated infrastructure costs based upon multiple sources including actual average project cost data and various studies.[82] 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 3-8. 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% of US-MR costs for both public fleets and public transportation projects, while covering up to 50% of CS-MR costs (see **Table 3-9**). In contrast to the EV Make Ready Program, in which 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.

[81] 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.
[82] See more details in the MHD Make Ready Study which can be found in 2023 Utility 2.0 Plan.

Table 3-9. Fleet Make-Ready Program US-MR and CS-MR Cost Coverage (by project type)

Project Type	US-MR[83]	CS-MR
Public Fleets	100% coverage	no coverage
Public Transportation	100% coverage	50% coverage in DACs;[84] 20% coverage for all other eligible customers[85]

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

- $50,000 for public fleets projects; and
- up to $200,000 for public transportation projects.

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.

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.[86]

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

[83] No customer deposit or CIAC is required.
[84] To qualify for the higher CSMR coverage under the public transportation offering, the project location needs to be within a DAC.
[85] To be paid by the Utility as reimbursement at the end of construction, after final inspection.
[86] These requirements are subject to change upon rollout in Q3 2024.

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.

3.2.1.1.2. Schedule Update

Phase 1 of the EV Make-Ready Program launched in mid-2021, and Phase 2 launched in early 2022 (see **Table 3-10**). The Transportation Electrification Team proposes to extend the EV Make-Ready and Fleet Make-Ready Programs to 2030 to allow the Utility to continue to serve the market. The assumed amount of infrastructure planned to be deployed in each year will continue to vary. All aspects of program management and data collection will span the full duration of infrastructure and incentive deployment.

Table 3-10. Make Ready Program Proposed Schedule

Program Name	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Make Ready Program										
EV Make Ready Program										
Fleet Make Ready Program										
Fleet Advisory Service										

3.2.1.2. Funding Reconciliation and Request

The EV Make Ready Program spent approximately \$3.37 million in 2023. The spending is less than originally budgeted, 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 2024 is approximately \$12.07 million, of which around \$7.6 million is planned for EV Make-Ready US-MR and CS-MR incentives, and \$2.5 million is for the NYSERDA Clean Transportation Prize.[87] The forecasted budget for 2025 is approximately \$15.55 million, of which around \$11.7 million is planned for EV Make-Ready US-MR and CS-MR incentives, and \$1.5 million is for the NYSERDA Clean Transportation Prize.

The forecasted budget for Fleet Make-Ready Program in 2024 is approximately \$2.12 million, of which around \$1.07 million is planned for Fleet Make-Ready US-MR and CS-MR

[87] LIPA had signed an MOU with NYSERDA to award up to \$7.5M towards this effort. PSEG Long Island has been requesting funding for this award through Utility 2.0. Circuit (an EV shuttle service provider) was selected for the NYSERDA Clean Transportation Prize in 2020, but has faced a number of delays due to licensing, permits, and vehicle delivery.

incentives, and $0.58 million is for the Fleet Advisory Service[88]. The budget largely consists of the costs associated with the deployment of infrastructure and incentives but also includes program management and IT costs such as Captures Database (see **Table 3-11** and **Table 3-12**). The forecasted budget for 2025 is approximately $2.62 million, of which around $1.94 million is planned for incentives, and $0.31 million for the Fleet Advisory Service.

The Make Ready Program requests 1 additional FTE to start in Q1 2025 to help the program keep up with the growing demand, as well as supporting overall customer engagement and outreach efforts, and coordination among internal and external stakeholders. An emphasis on customer engagement and outreach through contractor outreach, stakeholder engagement, and other Marketing, Education, and Outreach initiatives is critical to further EV adoption and charger installation.

The overall budget request in 2025 is higher than previously outlined due to the proposed increase of EV Make-Ready program port targets.[89] The incentives planned for 2025 is approximately $2.4 million higher.

The overall updated annual budget and variance are shown in **Table 3-11** and **Table 3-12**. It is important to note that budgetary values presented in the tables below are rounded to the thousandths decimal place.

Table 3-11. Capital and Operating Expense Actual, Forecast, and Projected[90]

		Actual ($M) 2023	Updated Forecast ($M) 2024	Request ($M) 2025	Projected (Not Requested) ($M) 2026	Total ($M)
EV Make Ready	Capital	0.138	4.234	6.274	6.292	16.938
	O&M	3.231	7.842	9.277	16.130	36.481
	Total	**3.369**	**12.076**	**15.551**	**22.422**	**53.419**
Fleet Make Ready	Capital	-	0.808	1.556	2.480	4.844
	O&M	0.164	1.310	1.063	1.349	3.886
	Total	**0.164**	**2.118**	**2.619**	**3.829**	**8.730**
Full Program	Capital	0.138	5.042	7.830	8.772	21.782
	O&M	3.395	9.152	10.340	17.479	40.367
	Total	**3.533**	**14.194**	**18.170**	**26.251**	**62.149**

[88] The budget request for Fleet Advisory Service includes one FTE and the Fleet Advisory Online Tool.
[89] The budget is updated based on a forecast developed by a third-party consultant (Gabel Associates) as discussed above.
[90] A portion of the Capital Forecasts for 2024-2026 are attributed to Capital Expenditure for Utility 2.0 PMO Support on the Make-Ready Programs.

Table 3-12. Capital and Operating Expense Budget, Forecast, and Variance

		2023 ($M)	2024 ($M)	2025 ($M)
Existing Program *(EV Make Ready)*	Capital	(0.715)	0.274	2.295
	O&M	(2.014)	(0.449)	(0.699)
	Total	**(2.729)**	**(0.175)**	**1.596**
Existing Program *(Fleet Make Ready)*	Capital	-	-	0.086
	O&M	(0.071)	(0.018)	(0.040)
	Total	**(0.071)**	**(0.018)**	**0.046**
Full Program	Capital	(0.715)	0.274	2.381
	O&M	(2.085)	(0.467)	(0.739)
	Total	**(2.800)**	**(0.193)**	**1.642**

3.2.1.3. Performance Reporting

Through Q4 2023, 312 L2 and 158 DCFC ports have been energized through the EV Make-Ready Program. Key performance indicators (KPIs) and program benefits for EV Make-Ready are detailed in **Table 3-13** and **Table 3-14** The Fleet Make-Ready Program will track these KPIs separately. [91]

Table 3-13. EV Make-Ready Program KPIs

Benefit	BCA Target Through 2023	Realized Through 2023[92]	Realized %[93]
# of DCFC Ports Pre-Approved	226	222	98%
# of L2 Ports Pre-Approved	631	733	116%
# of DCFC Ports Energized	189	158	84%
# of L2 Ports Energized	463	312	67%

[91] See additional information on Fleet Make-Ready Program performance tracking in the section below.
[92] The KPIs and Program Benefits shown in Table 3-13 and Table 3-14, respectively, for the EV Make-Ready Program were corrected to reflect the corrected Pre-Approved and Energized L2 Port Count in 2022.
[93] Percentage Realized is based on BCA Target.

Table 3-14. EV Make-Ready Program Benefits

Benefit	2023 YTD Target ($M)	2023 YTD Realized ($M)	Realized %[94]
Avoided Carbon Emissions	3.56	2.86	80%
Avoided Gasoline Consumption	23.10	18.39	80%
Vehicle O&M Savings	4.70	2.96	63%
Gasoline Security Value	3.53	2.81	80%
Federal Tax Credit	47.10	22.59	48%

Additionally, PSEG Long Island is tracking and has been sharing how the program benefit customers in DACs through DPS Quarterly Reports. Based on preliminary data, in 2023, more than 47% of the applicable program incentives were allocated to projects located within 1 mile or in DACs.[95]

3.2.1.3.1. 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, as mentioned above. 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 will include: [96]

- 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.

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

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[94] Percentage Realized is based on BCA Target.
[95] Note that there was a program guideline change in March 2024 and the 1-mile radius is no longer applied to projects pre-approved after this program change announcement.
[96] This list may be updated based upon potential program design updates.

the data collection and management process to standardize and streamline the reporting process.

3.2.1.4. Lessons Learned

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

Table 3-15 shows feedback PSEG Long Island has received as well as improvement opportunities and actions that PSEG Long Island may take to better support customer needs and improve customer experience.

PSEG Long Island continues to make improvements to the Make-Ready program offerings and will continue to do so by staying up to date with industry trends, engaging EV ecosystem partners, and reflecting on customer feedback to ensure efficient and successful program implementation.

Table 3-15. 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 has been making significant improvements to existing application process. Such efforts include utilizing TRC Captures,[97] like the EE Program, where a centralized database will allow PSEG Long Island to monitor and process applications more efficiently. • Contractors will be able to utilize the Partner Portal to submit, monitor, and review their applications in TRC Captures; Intended to launch in 2025. • 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.

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

<table>
<thead>
<tr><th>Category</th><th>Feedback Received</th><th>Improvement Opportunities</th></tr>
</thead>
<tbody>
<tr><td></td><td>Customers and Contractors would like to get in touch with the TE Team via multiple platforms to ask questions and get an overview of the program.</td><td>The Team launched Open Office Hours with both virtual and in-person options. This allows attendees to get their questions answered and connect with the Team on various topics.
The Team plans on hosting four customer roundtables in 2024, including two Fleet and two EV Make-Ready Program roundtables.</td></tr>
<tr><td></td><td>Some customers are not clear if they are eligible to participate in the EV Make-Ready Program.</td><td>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 supports public and workplace charging applications, but not for charging their EV inventory.</td></tr>
<tr><td></td><td>Customers need better insights into what the available capacity is on the grid.</td><td>PSEG Long Island developed an EV hosting capacity map that is available for customers to access.</td></tr>
<tr><td></td><td>Through monitoring program participation, PSEG Long Island has observed that there is a high interest in L2 adoption.</td><td>The Team updated its EV Make-Ready forecast to increase L2 port targets in 2025 and beyond.</td></tr>
<tr><td>Interest Area</td><td>Customers are eager to understand how to begin fleet electrification.</td><td>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 serves both public and private fleet customers since Q3 2023. The fleet advisor has been assisting customers to help them get started with their fleet electrification efforts.</td></tr>
</tbody>
</table>

Category	Feedback Received	Improvement Opportunities
Marketing, Education & Outreach (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 2024 and beyond. For example, the Team will update the EV website to provide simple, clear, and concise program instructions to assist customers through the enrollment process and improve customer experience. Additional information on the Transportation Electrification ME&O initiatives is detailed in the Customer Engagement sections under the Five-year plan.

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

3.2.1.5. Next Steps

PSEG Long Island will continue to promote the Make-Ready Program in 2024 and beyond and continue to provide the Fleet Advisory Service to support fleet electrification on Long Island.

3.2.2. EV Program

2024 Status	Active
2025 Status	Active
Start Year	2019
Funding Approved Through	2028
Description and Justification	In 2024, the EV Program consists of the Residential Charger Rebate Program and the DCFC Incentive Program. The Residential Charger Rebate Program was approved in 2023 and became available to residential customers from February 2024. The program is designed to be available to customers through 2028. The DCFC Incentive Program was modified to provide a 50% Demand Charge Rebate (DCR) to commercial customers in 2024 and will be discontinued when the new EV Phase-In Rate is implemented in 2025.

The EV Programs aim 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 continue to serve EV customers in 2024 and beyond.

3.2.2.1. Implementation Update

See the scope and schedule updates below for EV Programs.

3.2.2.1.1. Scope Update

Residential Program

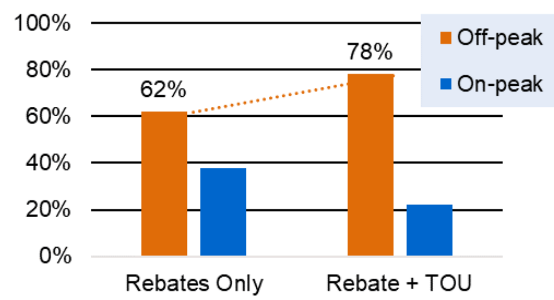
In 2024, PSEG Long Island reintroduced the Charger Rebate Program to help lower the upfront cost of purchasing EV associated charging equipment. The Residential Charger Rebate Program offers participants a cash rebate with the purchase of an Energy Star-rated L2 charger. [98] To help promote more equitable access to EVs, this program provides higher incentives for residential customers located within DACs, as well as LMI customers.[99] The rebate amounts are:

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

The 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 why they would not purchase an EV.[100] Other utilities that have established charger rebate pilots or programs also made similar observations. For example, Portland General Electric describes its pilot program on its website as making "EV ownership more affordable with rebates on qualified chargers so you can charge faster."[101]

Through the former Smart Charger Rebate Program, PSEG Long Island found that participating customers who are on TOU rates are more likely to charge during off-peak. As 82% of Long Island residents live in single-family homes, [102] having a Residential Charger Rebate Program that promotes L2 charging

Figure 3-4. EV Customer Charging Behavior Comparison



Source: PSEG Long Island Smart Charge Rebate Program

[98] Examples of Energy-Star Rated L2 chargers can be found here: https://www.energystar.gov/productfinder/product/certified-evse/results.
[99] The LMI customers are now also eligible for the higher incentive level per DPS recommendation.
[100] 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)
[101] PGE Smart Charging Program and Rebates Frequently Asked Questions. Accessed June 22, 2023. Home EV Charging Rebates FAQ | PGE (portlandgeneral.com)
[102] See additional information on Long Island housing here. PSEG Long Island supports *multifamily* EV charging infrastructure upgrades through the EV Make-Ready Program.

allows these customers to charge at home and take advantage of different pricing options offered by PSEG Long Island's Time of Use[103] and Time-of-Day rates by charging during off-peak or super off-peak hours to save more on their energy bills, as compared to Level 1 (L1) charging, which requires much longer charging time (compared to L2 charging) and may not be completed within the off-peak periods hours (see **Figure 3-4**).

Additionally, based on an 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, whereas only 40% of charging time needed can be met during super off-peak hours when utilizing L1. Therefore, incentivizing customers to charge at home using L2 charger may encourage more charging during super off-peak hours, resulting in greater grid benefits. While we currently do not require customers to be on the TOD rate to participate in this program, it is anticipated that most of our customers will have transitioned to TOD rates by 2026. Updates to the Residential Charger Rebate webpage will encourage customers to check out how they can maximize savings by charging their EV overnight on the TOD Super Off-peak Rate.

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. [104,105,106] The Residential Charger Rebate Program only offers UL-tested, and Energy Star-rated chargers. Through the Program, PSEG Long Island can support and advance the adoption of safe charging equipment.

Since the program became available to customers in February 2024, PSEG Long Island has seen strong interest in the program and have paid out more than 200 non-DAC or LMI applications and around 10 DAC or LMI applications as of May 2024. PSEG Long Island will continue to monitor program participation and may further increase incentive level for DAC or LMI customers in the future.

[103] PSEG Long Island's voluntary time of use rates are no longer available for new enrollment, however existing customers on these rates can remain on their rate.

[104] 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.

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

[106] 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 Program

In January 2023, the NY PSC released an Order[107] 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% 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 modified the DCFC Incentive Program which offered per-plug incentives through 2023 by launching a 50% demand charge rebate in 2024. All legacy DCFC Incentive Program participants made a one-time switch to begin participation in the 50% demand charge rebate in January 2024. Any new participants that enroll in the program after the beginning of 2024 will only be able to opt into the 50% demand charge rebate structure until the EV Phase-In Rate solution becomes available for customer participation.

See **Table 3-16** below for upcoming program offering shifts.

Table 3-16. EV Program Commercial Offering Updates

2024 Offering	2025 Offering		2026 Offering
	H1 2025	H2 2025	
Demand Charge Rebate	Demand Charge Rebate	EV Phase-In Rate	EV Phase-In Rate

In 2024, the DCFC Incentive Program offers a 50% Demand Charge Rebate, which replaced the Per-Plug Incentive. Participating customers can receive the Demand Charge Rebate until the EV Phase-In Rate becomes available, which is slated to become available for customer enrollment in the second half of 2025.

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

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

factor.[108] Within each graduation level, there would be a customer charge, a TOU energy charge, and a demand charge component with varying ratios.

3.2.2.1.2. Schedule Update

PSEG Long Island launched the Residential Charger Rebate Program in February 2024. The DCFC program now provides 50% Demand Charge Relief in 2024, followed by the EV Phase-In Rate in 2025. **Table 3-17** details the proposed schedule for the EV Program.

Table 3-17. EV Program Schedule

Program Name	2024	2025	2026	2027	2028	2029	2030
Residential Programs							
Charger Rebate Program							
Commercial Programs							
DCFC Incentive Program							
EV Phase-In Rate							

3.2.2.1.3. Risks and Mitigations

Table 3-18 outlines the potential risks and proposed mitigation steps for the implementation of the EV Phase-In Rate.

Table 3-18. Risk and Mitigation Assessment – EV Phase-In Rate

Category	Risk	Mitigation
Schedule	Given the complexity of the EV Phase-In Rate and priority to implement the TOD program, 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.	Develop a targeted customer communication plan in support of the EV Phase-In Rate rollout. Train relevant customer service representatives to better assist customers.

[108] 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).

3.2.2.2. Funding Reconciliation and Request

The EV Program spent approximately $0.8 million in O&M in 2023. The spending was slightly less than what was budgeted for due to less enrollment in the DCFC Incentive Program than forecasted. The DCFC Incentive Program requires approximately $1.49 million in O&M to pay out Per-Plug Incentive or Demand Charge Rebate in 2024, and requests $1 million to provide participating customers with 50% Demand Charge Rebate in 2025.

The forecasted budget for 2024 is slightly less than the approved budget primarily due to the planned IT budget for EV Phase-In Rate would mainly occur in 2025 instead of 2024. The implementation of the EV Phase-In Rate requires approximately $0.69 million in 2024 to account for incremental IT development costs, as well as a third-party consultant[109] to assist the implementation of the rate in 2024 (see **Table 3-17** and **Table 3-18**). It further requires approximately $1.9 million for the aforementioned two cost categories in 2025.[110] Additionally, the EV Program requests 1 additional FTE to focus on research and analytics, regulatory filing, reporting, and program development to develop reports and provide data-based insights to help the Team more effectively implement programs that fit customer needs and PSEG Long Island's goals.

The Residential Charger Rebate Program requests $1.3 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.

PSEG Long Island further requests $250,000 for outreach and marketing to be able to enhance engagement and outreach efforts to residential and commercial customers, with an emphasis on DAC customers, to increase EV adoption and program enrollment.

The updated annual budget and variance are shown in **Table 3-19** and **Table 3-20**. It is important to note that budgetary values presented in the tables below are rounded to the hundredths decimal place.

[109] The third-party consultant will provide coordination and planning support, business process design, and change management support.
[110] PSEG Long Island anticipates that the rate will go live in H2 2025; thus, does not anticipate incremental costs beyond 2026 at the time of 2024 Utility 2.0 Plan. However, needs assessment for 2026 will be determined and confirmed in 2025 Utility 2.0 Plan and budget reconciliation process.

Table 3-19. Capital and Operating Expense Budget, Actual and Forecast ($M)[111]

		Actual ($M) 2023	Updated Forecast ($M) 2024	Request ($M) 2025	Projected (Not Requested) ($M) 2026	Total ($M)
Demand Charge Rebate	Capital	-	-	-	-	-
	O&M	0.84	1.49	1.00	-	3.32
	Total	0.84	1.49	1.00	0.00	3.32
EV Phase-In Rate	Capital	-	0.70	2.01	0.11	2.82
	O&M	-	-	0.19	0.20	0.39
	Total	-	0.70	2.20	0.31	3.21
Residential Charger Rebate Program	Capital	-	-	-	-	-
	O&M	-	1.37	1.38	1.38	4.15
	Total	-	1.37	1.38	1.38	4.15
Marketing and Outreach	O&M	0.02	0.13	0.25	0.20	0.60
Full Program	Capital	-	0.70	2.01	0.11	2.82
	O&M	0.86	2.99	2.82	1.78	8.46
	Total	0.86	3.69	4.83	1.89	11.28

Table 3-20. Capital and Operating Expense Variance

		2023 ($M)	2024 ($M)	2025 ($M)
Demand Charge Rebate	Capital	-	-	-
	O&M	(0.42)	-	(1.35)
	Total	(0.42)	-	(1.35)
EV Phase-In Rate	Capital	-	(0.57)	1.19
	O&M	-	-	0.19
	Total	-	(0.57)	1.38
Residential Charger Rebate Program	Capital	-	-	-
	O&M	-	0.03	0.03
	Total	-	0.03	0.03
Marketing and Outreach	O&M	(0.01)	-	0.12
Full Program	Capital	-	(0.57)	1.19
	O&M	(0.43)	0.03	(1.01)
	Total	(0.43)	(0.54)	0.18

[111] A portion of the Capital Forecasts for 2024-2026 are attributed to Capital Expenditure for Utility 2.0 PMO Support on the EV Programs.

3.2.2.3. Performance Reporting

The metrics for the EV Program track the participation rates in the residential and public charging programs. For the Residential Charger Rebate Program, the number of participants is tracked via the number of Charger rebates paid to customers. The participation in the DCFC Incentive program is tracked as the number of DCFC ports committed and energized. The total number of participants in the residential smart charger rebate program was higher than expected (**Table 3-21**).

Table 3-21. EV Program KPIs

Benefit	Target Through 2023	Realized Through 2023	Realized %
Number of Smart Charger Rebates Paid[112]	4,162	6,901	166%
Number of EVs Sold on Long Island	39,647	43,707	110%
Number of DCFC Program Ports Energized	NA[113]	100[114]	NA

Participation in the Smart Charger Rebate Program exceeded expectations, and as a result allowing for all benefits to exceed targets through 2023, as shown in **Table 3-22**.

Table 3-22. EV Program Benefit Reporting

Benefit	Target Through 2023 ($M)	Realized Through 2023 ($M)	Realized %
Customer O&M Savings	6.57	8.41	128%
Additional Energy Sales	9.81	14.43	147%
Reduced Fuel Emissions	2.31	3.37	146%

3.2.2.3.1. Performance Measurement and Reporting for EV Phase-In Rate

PSEG Long Island tracks the aforementioned metrics for the Residential Charger Rebate Program.

[112] This KPI is representative of through 2022 as the Smart Charger Rebate program was discontinued in 2022.
[113] The DCFC Incentive Program was extended to provide demand charge rebate until the EV Phase-In Rate becomes available. Thus, the original program forecast no longer applies. The updated forecast is detailed in the supporting budgetary documentation submitted on July 1st, 2024.
[114] Upon review of DCFC ports enrolled in the program, a number of projects were found not in compliance with program guidelines. Thus, those ports would no longer be able to receive the incentives offered under the DCFC Incentive Program. The port number was updated from 187 to 100 and this change is consistent with the supporting budgetary documentation submitted on July 1st, 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

3.2.2.4. 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 brought back the program and broaden equipment eligibility to cover a broad range of Energy Star rated L2 chargers, as well as offering additional incentives for customers in DACs, as well as LMI customers. PSEG Long Island also plans on updating the EV Program website to provide additional resources and information to customers to promote EV adoption.

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.

3.2.2.5. Next Steps

PSEG Long Island will continue to monitor LMI / DAC customer participation in the Residential Charger Rebate Program and may further increase incentive level for LMI / DAC customers if their program participation is significantly below 35%. PSEG Long Island will continue to promote the DCFC Incentive Program in 2024 and will work to plan for a successful implementation of the EV Phase-In Rate in 2025.

3.2.3. Suffolk County Bus Make-Ready Pilot

2024 Status	Active
2025 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 MDHD 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. After the buses are deployed, the bus and charger data will be evaluated in 2026.

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 transit fleets. This pilot goes beyond of the scope of the EV Make-Ready Program, which is focused on light duty vehicle charging infrastructure, to explore make-ready infrastructure requirements for medium- and heavy-duty (MDHD) vehicles, specifically public transit fleets. Through this pilot, PSEG Long Island is working with Suffolk County to support the construction of the necessary make-ready infrastructure for two charging sites (West Babylon and Ronkonkoma). Upon completion, the deployed Make-Ready infrastructure is expected to support the charging requirements of approximately 40 buses (20 buses at each site).

Suffolk County does not operate its transit system directly. Instead, the County retained operators through a competitive solicitation process, which was finalized in Q3 2023. While Suffolk County will own the EV buses and the chargers to support them, the Operators own the depots and pay for the investments needed to accommodate the electric bus charging. When this pilot program was being proposed, Suffolk County was nearing the end of its operator agreement terms which was unknown to PSEG Long Island at the time.

3.2.3.1. Implementation Update

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

3.2.3.1.1. Scope Update

The scope remains as previously proposed in the 2021 Utility 2.0 Plan. The pilot is divided into three primary workstreams / stages (as shown below) and the PSEG Long Island project team is currently on Stage 2 (as of Q2 2024).

- **Finalize Cost Estimates:** PSEG Long Island worked with Suffolk County and Suffolk County's Transit Operators to develop more refined and finalized cost estimates for both the US-MR and CS-MR infrastructure. The refined costs were used determine PSEG Long Island's contributions to the make-ready costs (as described in Section 3.2.3.2).

- **Deploy Make-Ready:** Since the incumbent Transit Operators were selected, it was confirmed that the make-ready infrastructure for the West Babylon location was deployed in 2023. The make-ready infrastructure for the Ronkonkoma location is expected to be deployed by the end of Q4 2024. Both sites are expected to be officially completed by Q3 2025 once the final charger wiring can be installed and the buses are delivered. Based on the cost contributions determined in the first stage, PSEG Long Island will either deploy capital for the US-MR costs (if they have not yet been undertaken) or refund any contribution in aid of construction (CIAC) payment already made and send rebates for the CS-MR costs, if applicable.

  The make-ready infrastructure includes all equipment, materials, and construction needed to supply power to the charging stations. The requirements of each project vary widely, and site assessments were completed to determine the exact needs for infrastructure such as switchgear, new electrical service, meters, conduit, and conductors. The make-ready infrastructure is divided into two components: utility-side (US-MR) and customer-side (CS-MR). LIPA owns the US-MR infrastructure, and PSEG Long Island is responsible for the necessary construction, though is not necessarily responsible for covering the full costs. The CS-MR includes all infrastructure between the meter and the actual charging equipment. The customer is responsible for the construction and financing of the CS-MR infrastructure, though they may receive rebates from the utility to help cover the costs.

- **Data Collection & Evaluation:** After the make-ready infrastructure has been deployed and transit buses delivered (likely by Q3 2025), Suffolk County will begin operation of the electric buses. Over the course of 12 months, PSEG Long Island will collect AMI data from Suffolk County. The AMI data will be evaluated to determine the sufficiency of the charging infrastructure, the timing of charging activity, and gain insight to apply to future support for public transit electrification.

3.2.3.1.2. Schedule Update

PSEG Long Island expects the pilot to be completed by 2025 instead of 2023 as originally proposed in the 2021 Utility 2.0 Plan, with the exception that the bus and charging data will be evaluated in 2026. The pilot schedule was delayed due to a malware attack that Suffolk County experienced in September 2022, delays in the RFP and contracting processes, and later-than-expected anticipated delivery date of the electric buses. Due to these delays, the two sites are expected to be completed and up and running with rebated fully paid by the end of 2024.

Suffolk County issued an RFP in December of 2022 for Operators of its transit system. Responses to the RFP were received and Suffolk County awarded the incumbent operators with new contracts in early Q3 2023. Since the incumbent transit operators were awarded the next contract for transit operations for this pilot, the charging infrastructure will be at two locations: West Babylon and Ronkonkoma.

Upon awarding the Operators, Suffolk County learned that one of the Operators had already built out their site (West Babylon) for 1.5 MW of US-MR infrastructure. The final installation of wiring (CS-MR) at this site is expected to be completed in Q2 2025 and invoices to the contractors will be issued upon cost item completion at the site. At the Ronkonkoma site, construction for 1.5 MW both US-MR infrastructure and installation of CS-MR started in March 2024. Concrete Pads have been installed for both transformers and the switchgear, with an anticipated delivery date of the switchgear for the Ronkonkoma site in Q3 2024. The US-MR construction cannot be completed until the contractor for the Ronkonkoma site can determine charger specifications and pull the wire from the site. A portion of the final rebate payments for both sites are expected to be issued by the end of 2024, with the remaining payments made upon site completion in 2025.

Suffolk County plans on issuing Requests For Proposals (RFPs) for the procurement of EV transit buses and EVSE before the end of Q2 2024, which could result in buses not being delivered until Q3 2025. Once the RFP is finalized, the contractor can begin the next steps for CS-MR at both sites. A final analysis can only be completed following a 12-month data collection period that will occur once the buses are delivered and in operation. Thus, the final data analysis is expected to be completed by the end of 2026, which will be funded outside of the Utility 2.0 Program.

3.2.3.1.3. Risks and Mitigations

Table 3-23. Risk and Mitigation Assessment – Suffolk County Bus Make-Ready Pilot

Category	Risk	Mitigation
Technical	Charging equipment could be unavailable or flawed. Equipment replacement could lead to change in system infrastructure configuration.	Coordinate with Suffolk County to confirm assumptions around charging requirements. An objective of the initiative is to assess this risk and implement learnings in future support.

Category	Risk	Mitigation
Schedule	Significant delays in delivery of the electric buses, EVSE, or related infrastructure would lead to project delays and underutilization of the make-ready infrastructure.	Build flexibility into the project schedule to accommodate delays.
	Significant delays in scoping the schedule/plans with the 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.
Storm Response	Storm duty takes priority over everything, including project work. So, 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.

3.2.3.2. Funding Reconciliation and Request

The Suffolk County Bus Make-Ready Pilot had no budgetary spend in 2023 due to delays as described above in Section 1.1. The forecasted 2024 budget is as follows:

- **Make-Ready (Utility)**: Utility-side make-ready costs for two bus charging sites. The make-ready infrastructure includes all equipment, materials, and construction needed to supply power to the charging stations. The requirements of each project vary widely, and site assessments were completed to determine the exact needs for infrastructure such as switchgear, new electrical service, meters, conduit, and conductors.

  In the 2023 Utility 2.0 Plan, the initial US-MR cost estimate for West Babylon was approximately $2,500, which was doubled to $5,000 Total to consider similar expenditures needed for the Ronkonkoma site at the time of the Plan submission. It was also anticipated that the US-MR payments would be paid out by the end of 2023. However, these initial estimates did not materialize as planned due to overall timeline delays and because the 2024 invoiced actual cost for US-MR at Ronkonkoma was significantly more than what was anticipated due to the upgrades that were needed at the site. Thus, these budgetary changes are shown below and the payments to both sites will be made in 2024.

  - **<u>Estimated Total:</u>** $51,910.51
    - West Babylon: $2,721.86

- Ronkonkoma: $49,188.65

- **Make-Ready (Customer)**: Customer-side make-ready costs for two bus charging sites. The CS-MR includes all infrastructure between the meter and the actual charging equipment. The customer is responsible for the construction and financing of the CS-MR infrastructure, though they will receive rebates from the utility to help cover the costs. Due to overall pilot delays as a resulting of contracting and procurement delays, the customer-side make-ready costs will be paid out for the two bus charging sites (West Babylon $304,290 and Ronkonkoma $459,500) in 2024 and 2025 rather than as anticipated in 2023.

  In the 2023 Utility 2.0 Plan, the initial CS-MR cost estimate for West Babylon was predicted to be approximately $325,000. Based upon discussions internally and with Suffolk Transit, we anticipate that these costs will amount to $304,290 but will not be finalized until results from the RFP are concluded. The projected actual cost at Ronkonkoma is significantly more than what was anticipated during last year's Plan filing process due to switchgear upgrades that were needed at the site, so costs will amount to $459,500.

  - **<u>Estimated Total:</u>** $763,790[115]
    - <u>2024 CS-MR Costs:</u> $450,983
      - West Babylon: $176,983
      - Ronkonkoma: $274,000
    - <u>2025 CS-MR Costs:</u> $312,807
      - West Babylon: $127,307
      - Ronkonkoma: $185,500

- **EM&V**: After the make-ready infrastructure has been deployed, Suffolk County will begin operation of the electric buses. PSEG Long Island will collect at least 12 months of AMI and charging data from Suffolk County that will be evaluated to determine the sufficiency of the charging infrastructure and gain insight to apply to future support for public transit electrification. Given that at least one year of charging data is needed for the charging analysis and that buses could be delivered as late as Q3 2025, the Final Pilot Assessment Report cannot be developed until 2026.
  - **<u>Estimated Total:</u>** $40,000[116]

[115] There is a $500,000 incentive cap for each site (based upon per location cap as stated in Gabel EV Make-Ready Report)
[116] Funding for this task will come from outside the Utility 2.0 Program Funding and will not be incurred as a part of the project's Utility 2.0 Spend but rather internalized through the Core PSEG Long Island O&M Budget in 2026.

After 2025, assuming Suffolk County meets their schedule for infrastructure installations, the project scope of the pilot will be complete (outside of the Final Pilot Assessment Report, which will not be funded through the Utility 2.0 Program)[2].

The updated annual budget and variance are shown in **Table 3-24** and **Table 3-25**. It is important to note that budgetary values presented in the tables below are rounded to the hundredths decimal place.

Table 3-24. Capital and Operating Expense Budget, Actual and Forecast ($M)

	Actual ($M) 2023	Updated Forecast ($M) 2024	Request ($M) 2025	Projected (Not Requested) ($M) 2026	Total ($M)
Capital	-	0.05	-	-	0.05
O&M	-	0.45	0.31	-	0.76
Total	**-**	**0.50**	**0.31**	**0.00**	**0.81**

Table 3-25. Capital and Operating Expense Variance

	2023 ($M)	2024 ($M)	2025 ($M)
Capital	(0.01)	0.05	-
O&M	(0.65)	0.41	0.31
Total	**(0.66)**	**0.46**	**0.31**

3.2.3.3. Performance Reporting

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

- **Make-ready costs:** Record 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:** Calculate 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 AMI meter data from each site once operational to better understand 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.

3.2.3.4. Lessons Learned

Over the past year, the PSEG Long Island team learned that Fleet Operators and/or Developers may be hesitant to install CS-MR infrastructure until they know for certain the type of charger(s) that are being installed and if the chargers are compatible with the vehicles. In certain situations when work is solicited, long lead times may occur which could cause further timeline shifts and/or delays for a project.

Following the completion of the pilot, surveys and interviews with Suffolk County and its Transit Operators will provide insight into opportunities to improve future support. The lessons learned through this initiative will be used to support and scale up future programs related to electrifying transit fleets, including identifying opportunities to reduce infrastructure requirements through managed charging.

3.2.3.5. Next Steps

Suffolk County plans to issue Requests for Proposals (RFPs) for the procurement of EV transit buses and EVSE before the end of Q2 2024. Once the RFP is finalized, the contractor can begin the next steps for CS-MR at both sites. Additionally, PSEG Long Island will begin US-MR construction at Ronkonkoma Site and the installation of wiring at West Babylon site. Following installation, PSEG Long Island will also finalize charging specifications and follow-up with completed invoices. Final rebate payments for both sites are expected to be issued on a rolling basis upon cost item completion.

3.3. Transportation Electrification Five-Year Plan

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

- All new passenger cars sold in New York State to be zero-emissions by 2035
- Electrifying the state's light-duty fleet and 100% of school buses by 2035
- All new medium and heavy-duty vehicles (MHDV) sales to be zero-emissions by 2045

These transportation electrification targets are supported by initiatives that encourage wider adoption of electric vehicles (EVs). One key initiative is the statewide EV Make-Ready Program, which incentivizes greater deployment of EVSE such as Level 2 and Direct Current

Fast Chargers (DCFC) by providing funding to support Utility-Side Make-Ready (US-MR), and Customer-Side Make-Ready (CS-MR) infrastructure costs.

3.3.1. Current State

2025 Targets

2025 Goal	178,500 Light-Duty EVs
2025 Achievement (as of Q1 2024)	54,288 EVs (30%)

EV Target

PSEG Long Island has been working towards a 2025 light-duty EV adoption goal of 178,000 LDVs, which was established based on New York State's light-duty EV goal of 850,000.[117] This state goal was superseded by the Advanced Clean Car II that mandates that EV sales increase from 35% in 2025 to 100% in 2035.[118] PSEG Long Island's various transportation electrification initiatives will continue to support the adoption of 178,500 light-duty EVs on Long Island.

Program Target

The two main transportation electrification programs are the Make-Ready (MR) Program and the EV Program. The Make-Ready Program is consisted of: (1) the EV Make-Ready Program; and (2) the Fleet Make-Ready Program. The EV Make-Ready Program provides make-ready support to public, workplace, and MUD charging, aiming to energize 13,625 L2 ports and 783 DCFC ports by 2030.[119] To date, 312 L2 ports and 158 DCFC ports were energized through 2023. The Fleet Make-Ready Program was designed to provide make-ready infrastructure incentives to public fleet and public transportation charging with the goal to enroll 89 public fleet and 46 public transportation projects by 2028.[120]

The EV Programs are the Residential Charger Rebate Program and the DCFC Incentive Program, with the latter being replaced by EV Phase-In Rate in 2025. The Residential Charger Rebate Program provides charger rebates for at-home L2 charging with the goal of

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[117] New York State Climate Action Council. Scoping Plan – Full Report December 2022.
[118] New York State Senate. Senate Bill S7788 (2021-2022 Legislative Session).
[119] From April 2024's Gabel Forecast: During the first quarter of 2024, 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 based on EV adoption forecasts were developed in this third-party study.
[120] The scope and timeline of the Fleet Make-Ready program was evaluated in the Five-year plan.

issuing 25,000 rebates (35% of which dedicated to DAC customers) to customers from 2024 to 2028.

Additionally, the Suffolk County Bus Make-Ready Pilot also has delivery of buses expected by the end of December 2024.

3.3.2. Future State

2030 Targets

2030 Target	N/A
2030 Achievement (as of Q1 2024)	54,288 EVs (x%)

EV Target

PSEG Long Island has not established a 2030 goal as the state guideline is not available at the time of publishing the 2024 Utility 2.0 Plan.

Program Expansion

PSEG Long Island identified areas where the Transportation Electrification (TE) Team could expand offerings for EV customers to address barriers to EV adoption and charging infrastructure deployment. From 2025 to 2030, PSEG Long Island plans to enhance engagement and outreach efforts to residential and commercial customers, with an emphasis on DAC customers, to increase EV adoption and program enrollment. PSEG Long Island will also increase overall port targets and prioritize DAC customer participation under the EV Make-Ready Program beyond 2026. Furthermore, leading up to 2030, PSEG Long Island plans to expand customer segment eligibility and project targets under the Fleet Make-Ready Program beyond public fleets and public transportation to increase electrification opportunities for a broader MHD fleet customer base. Lastly, PSEG Long Island plans on developing managed charging offerings that encourage charging behavior that benefits the grid and the environment, while reducing energy bill impacts for commercial and residential customers. PSEG Long Island plans on expanding offerings over the next five years to enable LD EV adoption and MHD electrification.

3.3.3. Transportation Electrification Five-Year Plan

3.3.3.1. 2025 Programs & Resources Summary

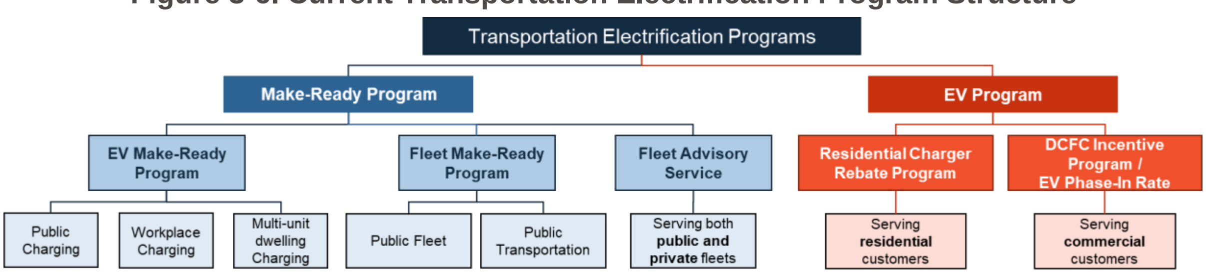
PSEG Long Island supports the build out of EV infrastructure and overall adoption of EVs through a variety of programs and offerings for residential, commercial, and fleet customers. The following section discusses PSEG Long Island's offerings for EV customers through 2025, many of which will be expanded in the Five-year plan to further support transportation electrification efforts. The current state is discussed in three categories: programs and rates, customer engagement, internal planning and processes, as depicted in **Figure 3-5**.

Figure 3-5. Five-Year Plan Strategic Pillars

Programs & Rates

PSEG Long Island currently offers several programs to support residential, commercial, and fleet customers. These programs include the Make-ready Program and Electric Vehicle Program. **Figure 3-6** illustrates the *current* structure of PSEG Long Island's programs and target customers served.

Figure 3-6. Current Transportation Electrification Program Structure



Make-Ready Program

The Make-Ready (MR) Program was developed in line with the NY PSC EV Make-Ready Order that recommended that the regulated utilities offer financial contributions for Make-Ready infrastructure to accelerate EVSE deployment and enable EV adoption. Following the Order, PSEG Long Island developed the Make-Ready Program in 2021 to support investment for new DCFC and L2 charging stations. Since then, the Make-Ready Program has been expanded to include the EV Make-Ready Program, the Fleet Make-Ready Program, and the Fleet Advisory Service.

1. **EV Make-Ready Program:** The EV Make-Ready Program was updated to provide incentives for make-ready infrastructure to support the deployment of public, workplace, and MUD charging infrastructure on Long Island until 2030.[121]
2. **Fleet Make-Ready Program:** Beginning in Q3 of 2024, PSEG Long Island plans to launch the approved Fleet Make-Ready Program. The Fleet Make-Ready Program serves two target markets that would most likely benefit customers in DACs:
    a. Public fleets which cover local government, public serving, and not-for-profit organizations; and
    b. Public transportation, such as school and transit buses.

   While other New York State 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. The approved Fleet Make-Ready Program will provide Utility-Side and Customer-Side Make-Ready incentives to eligible fleet customers operating LDVs and MHDVs on Long Island.

3. **Fleet Advisory Service:** The Fleet Advisory Service launched in Q3 of 2023 to provide a complimentary online tool and fleet advisor to both public and private fleets. The Fleet Advisory Online Tool 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. The Fleet Advisor provides additional advisory services to fleet customers through their electrification journey, as well as support on customer outreach and engagement.

EV Program

The EV Programs aim to increase EV adoption, align EV customer adoption strategy with reducing GHG emissions, empower customers, accelerate the deployment of EVSE, improve system efficiency, and encourage off-peak charging. The EV Programs consist of one residential program, the Residential Charger Rebate Program, and one commercial program, DCFC Incentive Program, which will be replaced by EV Phase-In Rate in H2 2025.

1. **Residential Charger Rebate Program:** Starting in February 2024, the Residential Charger Rebate Program provides rebates on eligible EVSE to further reduce barriers to EV adoption. Customers are eligible to receive charger rebates for at-home Energy Star L2 Chargers through 2028. Additionally, the Program aims to

[121] The scope and timeline of the EV Make-Ready program was evaluated in the Five-year plan.

dedicate at least 35% of total program budget to DAC customers. Participating customers will also be able to enroll in PSEG Long Island's TOD rate(s) to increase bill savings when charging during off-peak and/or super off-peak hours. TOD serves as a method to managing and potentially reducing load on the grid during peak hours by providing price signals to trigger customer behavioral changes, especially with the increased adoption of EVs.

2. **EV Phase-In Rate:** For commercial customers, the DCFC Incentive Program will continue to provide Demand Charge Relief to commercial customers in 2024 but will later be discontinued when the new EV Phase-In Rate is implemented in 2025, in line with the January 2023 Order from NY PSC. The EV Phase-In Rate will enable customers to reduce the cost of charging by alleviating the impact of demand charges.

Other Programs

PSEG Long Island also offers tariffs and resources such as Vehicle-to-Grid (V2G) and the EV Hosting Capacity Map to enable customers and provide additional benefits to EV drivers and owners. Through the Fleet Advisory Service and customer engagement, several fleet owners and commercial customers have expressed interest in V2G programs. PSEG Long Island offers a Demand Reduction Value (DRV) tariff that allows EV owners to schedule their EV to be available to discharge to the grid. Under DRV, customers receive compensation on a $/kWh basis, while also helping PSEG Long Island alleviate grid constraint. The TE team will highlight these offerings to fleet customers on EV webpages and webinars through website updates. EV Hosting Capacity Maps are currently available on PSEG Long Island's website as an informational tool for EV customers and contractors. These maps can help identify the available capacity on a feeder and help customers and contractors make informed decision on charging site development. All hosting capacity maps are 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.[122]

Customer Engagement

The Transportation Electrification Team plans on enhancing its Marketing, Education, and Outreach efforts which includes implementing five main initiatives[123] that are critical to enhancing customer experience and increasing EVSE deployment on Long Island.

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[122] Users wishing to access the hosting capacity map are required to submit a Hosting Capacity Map Access Request form to PSEG Long Island and pass a CLEAR check (a simplified background check). Once the process is completed, an email notification will be sent with credentials and instructions.
[123] These initiatives are also meant to continue. Additional information can be found in the "Future State" section below.

1. **Website Updates:** In 2024, the TE Team plans on enhancing EV webpages to provide simple, intuitive and trusted information on EVs, charging, available programs, and resources and tools to streamline customer participation, with messaging based on targeted customer segments.
2. **Internal EV Program Training of Employees and Cross-functional Departments:** The Team will also conduct internal EV training throughout 2024 to enhance knowledge, communication, and understanding of EVs and EV Programs to help internal business units better serve customers.[124]
3. **Contractor Outreach Program:** The TE Team will expand contractor outreach in 2024 and beyond to develop and deepen relationships with contractors so they can act as an extension of the TE Team to drive participation in PSEG Long Island's EV Make-Ready and Fleet Make-Ready programs. These outreach efforts will include round tables similar to those being conducted in 2024.
4. **Stakeholder Partnerships:** The Team will increase engagement efforts with a prioritized list of stakeholders that includes dealerships, trade organizations, nonprofits, and schools and colleges. This includes direct engagement with stakeholders though events, meetings, ride-and-drive events, information seminars, collaborative events, and more, similar to those being conducted in 2024.
5. **Customer Round Tables:** The Team will host additional customer round tables in 2025 and beyond to continue promoting participation in both new and existing programs and collecting customer feedback.

The Utility Marketing team also developed a marketing plan for 2025 to support the engagement and outreach efforts. The TE Team will collaborate with internal business units to deliver tailored content to targeted customers, and help customers make informed decisions. The marketing plan will enhance customer access to EV Marketing and Education Materials that provide information on available programs, resources, and EV benefits to further EV adoption. Marketing efforts will also support the growth of partnerships between PSEG Long Island and external stakeholders. PSEG Long Island will conduct marketing outreach across multiple channels including owned, paid, and earned media.

Internal Planning and Processes

The TE team collaborates with multiple internal business units on program implementation, customer engagement, and internal planning and analyses. The following efforts are

[124] See additional information on Internal Training in the "Internal Employee Training" section below.

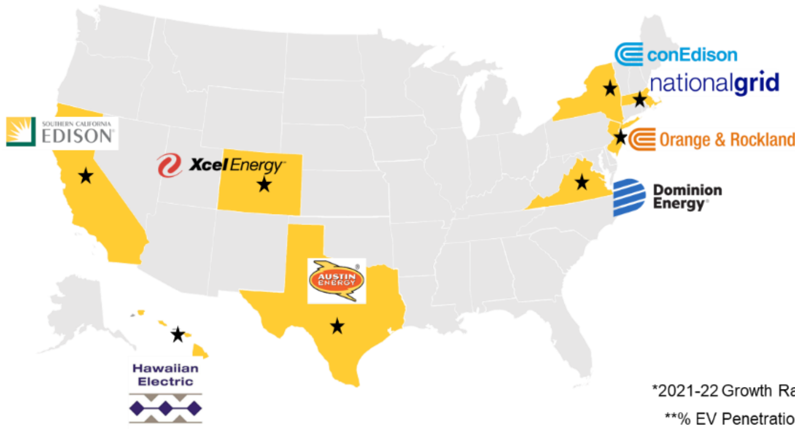
underway in 2024 to strengthen internal collaborations and improve customer engagement and experience.

1. **Internal Employee Trainings:** To help key internal stakeholders stay up to date on EV program offerings, the TE team spearheads internal employee trainings to prepare them for engaging with customers about EV programs, how to participate and engage with EV experts at PSEG Long Island, and when carrying out tasks related to EV programs. The trainings are structured on the level of informational needs and cognitive learning required in each functional role. Trainings range from online Introductory training to instructor-led courses by a member of the TE team. The goal of trainings is to strengthen internal stakeholder partnerships while also more effectively disseminating knowledge about EV programs to customers. The TE team will also align with internal stakeholder groups to increase EV knowledge for improved customer communications and experience.
2. **Transportation Electrification Team:** The TE team currently has six full-time employees (FTEs) but is aiming to add two new employees in 2025. The TE team's responsibilities currently include managing analysis & reporting, program implementation and collaborating with the Marketing team on customer education and outreach. The intention of the team expansion is that as the team expands, the staff will be able to dedicate their focus on specific tasks. Specifically, one new FTE will focus on research and analytics, regulatory filing, reporting, and program development to increase strategic initiatives and more effectively implement programs that fit customer needs and PSEG Long Island goals. The other new FTE will focus on education and outreach to support customer engagement and coordination among internal and external stakeholders. An emphasis on customer outreach will further EV adoption through a combination of trainings with internal stakeholders and external outreach strategies. Customers can expect quicker application and rebate processing, and more general support. Both FTEs will also be able to assist with program implementation as needed. As program participation increases, the TE team will assess if further resources are required to support the programs they administer.

3.3.3.2. Gap Analysis

The TE team first conducted a benchmarking analysis to identify programs and activities that peer utilities are utilizing to reduce barriers to EV adoption and charging infrastructure deployment. The benchmarking analysis investigated eight peer utilities that operate in states with some of the highest rate of EV adoption in the US. **Figure 3-7** shows the utilities included in the analysis which were Southern California Edison, Xcel Energy CO, Austin Energy, Dominion Energy, National Grid MA, Con Edison, Orange & Rockland, and Hawaiian Electric.

Figure 3-7. List of Benchmarked Utilities



State	2021-22 Growth Rate*	% EV Penetration**
TX	72%	0.8%
NJ	72%	1.6%
VA	68%	1.0%
CO	58%	1.5%
MA	52%	1.5%
NY	50%	1.3%
CA	44%	3.4%
HI	36%	2.3%
Long Island	18%	1.6%

*2021-22 Growth Rate is a percent change in EV population from 2021 to 2022.

**% EV Penetration is a percent of EVs to the total vehicle population in 2022.

The benchmarking analysis reviewed active EV programs and rates, internal processes, and customer engagement initiatives. Additionally, the analysis focused on DAC-specific support and engagement initiatives.

The TE team utilized the results of the benchmarking analysis to identify high-impact gaps within PSEG Long Island 's current and planned offerings and developed potential solutions that may be employed by the TE team in this five-year plan. The high-impact gaps were identified by the three Five-Year Plan Strategic Pillars: (1) Programs and Rates; (2) Customer Engagement; and (3) Internal Planning and Processes, as outlined in **Figure 3-5**.

2026-2030 Program & Resources Summary

The TE team used the results from the Gap Analysis to identify how future offerings for EV customers could be established or expanded to better support EV adoption on Long Island. The following section explains each of the new and expanded offerings available to customers between 2026 and 2030. Below are the key solutions proposed to fill gaps by strategic pillars:

- **Programs and Rates:** The TE team plans to lengthen the timeline, broaden eligibility and increase port goals for the EV Make-Ready and Fleet Make-Ready programs to further support EVSE deployment. The TE team will also be exploring managed charging pilots and/or programs across all customer groups to manage EV charging load and minimize adverse impacts on the grid.
- **Customer Engagement:** The TE team plans to increase education and outreach efforts for contractors, local dealerships and other key stakeholders to further accelerate EV adoption on Long Island. Additionally, the TE team plans to expand a range of online tools and resources on its website, which may include EV buyer's guides, rate calculators, site calculators, and contractor resources. These tools and

resources enable customers to make informed decisions through their electrification journey.

- **Internal Planning and Processes:** The TE team plans to explore automation when processing customer queries and applications for existing and planned programs to improve customer experience and reduce staff processing time. The TE team also plans to continue to conduct internal trainings to PSEG Long Island employees who have regular touchpoints with customers interested in EVs.

Customer Programs & Rates

Infrastructure Support

The TE team currently provides a range of programs that support EV charging infrastructure deployment to residential, commercial, and fleet customers. Based on the results of the Gap Analysis, this section outlines proposed modification and expansion of existing infrastructure support programs.

1. **Residential Charger Rebate Program:** PSEG Long Island will continue to promote the Residential Charger Rebate program through 2028 with a focus on equitable access to the rebates for residential customers located within DACs.
2. **EV Make-Ready Program:** The TE team plans to extend the program timeline from 2027 to 2030 with higher port goals. L2 port goal will be tripled and DCFC port goal will be increased by over 50%, with strategic prioritization of DAC participation. These program updates are based on: (1) DPS's Recommendation Letter that suggested that PSEG Long Island increase port counts to support the growing number of EVs; and (2) the Gabel forecast that utilized historical data and market trends to develop an annual EV count and subsequent port target to meet EV demand on Long Island. PSEG Long Island will continue to monitor the market and conduct analysis to better understand and project EV adoption trends. Infrastructure targets will be reviewed and updated accordingly to meet these needs and support EV adoption.
3. **Fleet Make-Ready Program:** Starting in 2027, the TE team plans to expand program eligibility to include private fleets, broadening electrification opportunities and customer segments. This proposed change is based on an expected increase in electrification interests and efforts among private fleets due to the

Advanced Clean Car and Advanced Clean Truck rule.[125,126] The program timeline will also be extended to 2030 so that private fleets on Long Island receive the support they need to electrify their vehicles and deploy charging infrastructure.

Rates and Load Management Strategies

From 2026 to 2030, PSEG Long Island will continue to provide options for customers to reduce electric bills and manage their charging load through rates and load management programs that also benefit the grid and Long Island community.

1. **Time-Of-Day (TOD) Rate:** Beginning late 2023, residential customers have been incentivized to charge EVs during off-peak and super off-peak hours (10PM to 6AM) under the Off-Peak and Super Off-Peak TOD rates, respectively. Customers will have the opportunity to save money and develop charging behavior that is most beneficial to the grid. The TOD rates will act as a passive managed charging program that incentivizes customers to charge off-peak and save on energy bills, while enabling PSEG Long Island to better manage EV load and alleviate grid constraint. PSEG Long Island will leverage data collected and lessons learned from the TOD rates to inform future development of EV load management strategies. To provide further shifting and saving insights to residential customers, PSEG Long Island will be sending AMI-disaggregation based monthly reports to customers with L2 chargers and customers with evident at-home charging patterns. These reports will highlight when customers are charging and how they can further optimize their savings with TOD rates.
2. **Managed Charging Roadmap:** The TE team has developed a five-year managed charging roadmap for both residential and commercial customers. The TE team conducted a benchmarking analysis against the JUs to understand how managed charging for residential and commercial customers could be successfully implemented. The TE team found that all the JUs offer residential managed charging programs and most offer an active residential managed charging program.

   Commercial managed charging pilots/programs follows a delayed timeline in comparison to residential managed charging programs because of increased data needs to understand load impacts and implementation solutions. Based on benchmarking analysis results, the TE team found that all the peer utilities pair an

125 ACC requires vehicle manufacturers to sell an increasing percentage of new zero-emission light-duty vehicles starting in 2026, reaching 100% new sales by 2035.
126 ACT requires that all new medium- and heavy-duty vehicles sold are zero-emissions by 2045.

EV Phase-In rate with passive commercial managed charging programs to effectively manage commercial EV charging load.

PSEG Long Island incorporated these findings into the five-year managed charging roadmap and will utilize similar strategies when designing managed charging programs in the future. Lessons learned from residential managed charging will be utilized for commercial managed charging.

a. **Residential Managed Charging Program:** PSEG Long Island will research potential methods to implement managed charging pilots and/or programs for residential customers. PSEG Long Island will analyze charging consumption data from the TOD rates to better understand its effectiveness and evaluate the need to either encourage residential customers to opt for the Super Off-peak Rate, which has a discounted rate during the super off-peak overnight period, or for an active managed charging program due to unintended consequences, such as timer peaks.[127] The impacts of timer peaks on distribution feeders could intensify as EV penetration grows. If such impacts are identified based on TOD data analysis, PSEG Long Island will develop and implement a residential active managed charging pilot. The pilot would provide direct controls so that residential EV charging load is shifted to off-peak without inadvertently causing the emergence of a timer peak demand period, while encouraging EV charging at times that increase system load factor. Additionally, this pilot would offer valuable insights into the effectiveness of an active managed charging approach, customer interests and responsiveness, and the ideal program design before expanding into a full program in the future. PSEG Long Island will also draw from the experiences of peer utilities when designing future managed charging programs.

b. **Commercial Managed Charging Program:** As contractors and fleet operators/owners begin to capitalize on transportation electrification opportunity, PSEG Long Island will conduct research and analysis on the needs to manage commercial charging load. Beginning in 2025, EV Phase-In rate will replace the DCFC Incentive Program that includes a 50% Demand Charge Relief. The EV Phase-In Rate is a commercial tariff specifically for public EV charging stations and commercial fleet

[127]Timer peak is an unintentional synchronizing effect on EV charging patterns being observed when EV charging is scheduled to coincide with the optimal TOU window or to begin charging simultaneously at the start of the off-peak pricing period in response to lower off-peak pricing. See more information here.

customers. It consists of four graduation levels based on participants' annual load factor. Within each graduation level, there would be a customer charge, a TOU energy charge, and a demand charge component with varying ratios. This will enable customers to reduce charging costs to further enable electrification. Since the EV Phase-In Rate does not manage load, PSEG Long Island will explore load management strategies in the commercial managed charging roadmap.

For this reason, PSEG Long Island will research passive commercial managed charging programs next year to potentially implement a commercial managed charging program in 2026, as a compliment to the EV Phase-In Rate. PSEG Long Island will also conduct a study on load impact from MHD fleet vehicles to forecast future load impact at a granular level. The TE team will evaluate the need for an EV Load Impact Study to evaluate future grid constraint at a system level based on EV adoption beyond just fleets vehicles. This will ultimately inform the TE team on the potential need for additional managed charging programs. If a passive managed charging program is implemented and is not effective in managing load impact, the TE Team plans on researching active managed charging solutions. Lessons learned from residential managed charging will also offer insight into the effectiveness of the program and challenges related to implementation. This will help develop a pilot that will offer insights into the need and structure of a future active managed charging program.

Advisory Support

The TE team will continue to provide Fleet Advisory Service to support fleet operators through their electrification journey. Insights collected from Fleet Advisory Service will be used to enhance program offerings and resources that best serve customer needs, such as refining website content and education collateral, and developing future programs.

Additionally, the TE team is implementing outreach efforts within internal and external stakeholder groups to better support EV customers and further EV adoption. These efforts will become an important communication channel to attract more fleet customers to Fleet Advisory Service. This feedback loop will be critical as more fleets on Long Island transition to electrified vehicles.

Customer Engagement

In the next five years, the TE team aims to continue strengthening the outreach and engagement efforts to its customers and stakeholders. These efforts will empower customers through meaningful engagement and cultivate impactful collaboration with stakeholders and partners, while positioning PSEG Long Island as a trusted source and advisor to provide relevant information.

1. **Marketing and Outreach Campaign:** PSEG Long Island plans to continue to deliver targeted marketing, education, and outreach to residential and commercial customers. The TE team will collaborate with the Marketing team and other internal business units to expand customer reach and utilize existing and new marketing channels to deliver tailored content to targeted customers. By improving customer access to EV educational materials, customers will have an increased awareness of EV benefits and relevant programs and resources that they can participate and/or use to make informed decisions. The Marketing team will utilize a variety of messaging, outreach channels and marketing campaigns through owned, earned, and paid media that will differ between customer segments to attract customer interests in transportation electrification, with specific emphasis on DACs. The Utility Marketing Team will annually update the Marketing and Outreach plan and tailor future outreach based on feedback and needs of customers, as well as the evolving market trends.
2. **Tools:** Based on the Gap Analysis, the TE team identified the need to provide additional tools for residential and commercial customers. These types of tools include providing a buyer's guide for residential customers with the ability to filter EVs based on driving habits, evaluate the total cost of ownership after incentives, and view/purchase charging equipment in a marketplace. This will empower customers to make informed decisions when switching to EVs. For commercial customers, the TE team is exploring site-specific tools which include a site calculator for contractors and customers who are evaluating how to make a return on investment, and a rate calculation tool to estimate charging costs based on location and time of use. This empowers customers and contractors with information on project profitability to improve site evaluation. Lastly, PSEG Long Island is exploring an imbedded charger map on the website to provide customers with more information on available public charging.
3. **Customer Roundtable:** The TE team will utilize lessons-learned from roundtable sessions in 2024 to increase engagement and improve content and experience for participants in 2025 and beyond. Future roundtables will focus on how participants can seek technical and financial assistance, such as how different program incentives from both PSEG Long Island and others can be stacked to minimize costs. The TE team will continue to invite speakers to share experience and success stories which has been found helpful for other routable participants. The peer-to-peer experience sharing helps concretize the program's messaging and give participants more tangible, real-world information. Roundtables will also emphasize a call-to-

action to urge participants to reach out to PSEG Long Island and engage in available programs.

- In addition, the TE team also plans on leveraging the partnerships with dealerships, non-profits, trade organizations, and other roundtable participants to build a robust network of customers to engage with going forward. These key stakeholder groups would participate in annual roundtables to promote customer participation in programs and inform participants on current, new, and future programs. Excerpts from these roundtables would be posted on the EV website. The TE team will also develop and distribute semi-annual newsletters to facilitate continuous engagement.

4. **Contractor Outreach:** The TE team plans on continuing the Contractor Outreach Program beyond 2025 to deepen relationships with contractors so that they can act as an extension of the TE team and help drive participation in EV Programs. The TE team plans to utilize communication platforms such as recurring discussions with contractors to capture feedback for potential program and process improvements. Additionally, the TE team will continue to identify reputable contractors through internal channels and external research which will help expand the list of contractors that interested EV customers can consider and reach out to.
5. **Stakeholder Partnership Building:** The TE team will continue to collaborate with other internal business units to further develop and strengthen partnerships with key external stakeholder groups, such as car dealerships, trade organization, non-profits, and schools and colleges. Dealerships serve as a key stakeholder because they often act as the first touchpoint for EV customers. Trade Organizations allow the TE team to reach more commercial customers, as well as developers and contractors. The TE team and relevant business units will continue to attend events and conduct outreach efforts to inform relevant EV program information and updates. Nonprofits are also an important stakeholder group for reaching customers, especially those in DACs. The TE team will continue to build partnerships with large nonprofit groups and local community organizations by having regular meetings, distributing marketing materials, or participating in community events. Lastly, the TE team will continue to collaborate on outreach efforts with schools and colleges. This includes giving speeches and trainings that provide educational opportunities on EVs and PSEG Long Island 's contribution to New York State's emission reduction goals.
6. **Website Updates:** The TE Team will evaluate the needs to update the EV website to reflect changes in programs, market trends and provide additional resources for customers. Specifically, the TE Team will conduct an annual content review and refresh to ensure that program progress is up to date and all available programs are listed.

Internal Planning and Processes

The TE team identified several efforts to streamline and enhance internal planning and processes related to EVs. These efforts will help ensure critical grid and charging infrastructure needed to support the transition to EVs are well-planned and ensure ease of EV adoption to all customers.

1. **Grid Impact Assessment:** Following the development of the Fleet Electrification Study, the TE team will collaborate with Distribution Planning team to conduct a Grid Impact Assessment as a result of EVs. This Assessment will evaluate when and where PSEG Long Island's grid will face capacity constraints at circuit and/or substation level. Results from this Assessment will help inform both Distribution Planning team and the TE team on the magnitude of EV charging impacts, as well as provide insights into opportunities to support the increased charging needs.
2. **Streamline Customer Request Processes:** The TE team has been engaging with relevant teams within PSEG Long Island to streamline customer request processes. The TE team is currently exploring a few enhancements to existing processes, including process streamlining in application processing which would ultimately reduce over staff time, while reducing wait time for customers. Another potential solution is to use a portal that automatically processes applications and flags issues. This would reduce staff involvement to only require inputs when issues arise. This would also drastically decrease customer wait times. Overall, process improvement would reduce the build-up of applications so that customers receive updates in timely manner and are efficiently enrolled in programs.
   - PSEG Long Island will similarly research methods to streamline customer requests by automating routing and query responses through interactive voice response (IVR) tools and chatbots, as potential additional channels to reach PSEG Long Island. Improving IVR tools enables customers to be automatously routed to appropriate call centers to reduce wait times. Customers will potentially be able to utilize voice commands to interact with a computer-operated telephone system. Some technology enables the system to extract intent and meaning from conversational sentences to accurately guide customers to the best-fit department or service center. Customers will receive faster and more accurate answers. Virtual assistants, like chat bots, serve a similar purpose. Rule-based response systems on websites or mobile apps enable autonomous responses to user queries. PSEG Long Island will research the utilization of rule-based, AI, or hybrid systems to efficiently and accurately route customers to the correct answer with minimal call center involvement.
3. **Customer Relationship Management (CRM) Tools:** PSEG Long Island will investigate the need for CRM tools to collect and maintain customer data to improve services and interactions. CRMs are designed to collect and store customer data to

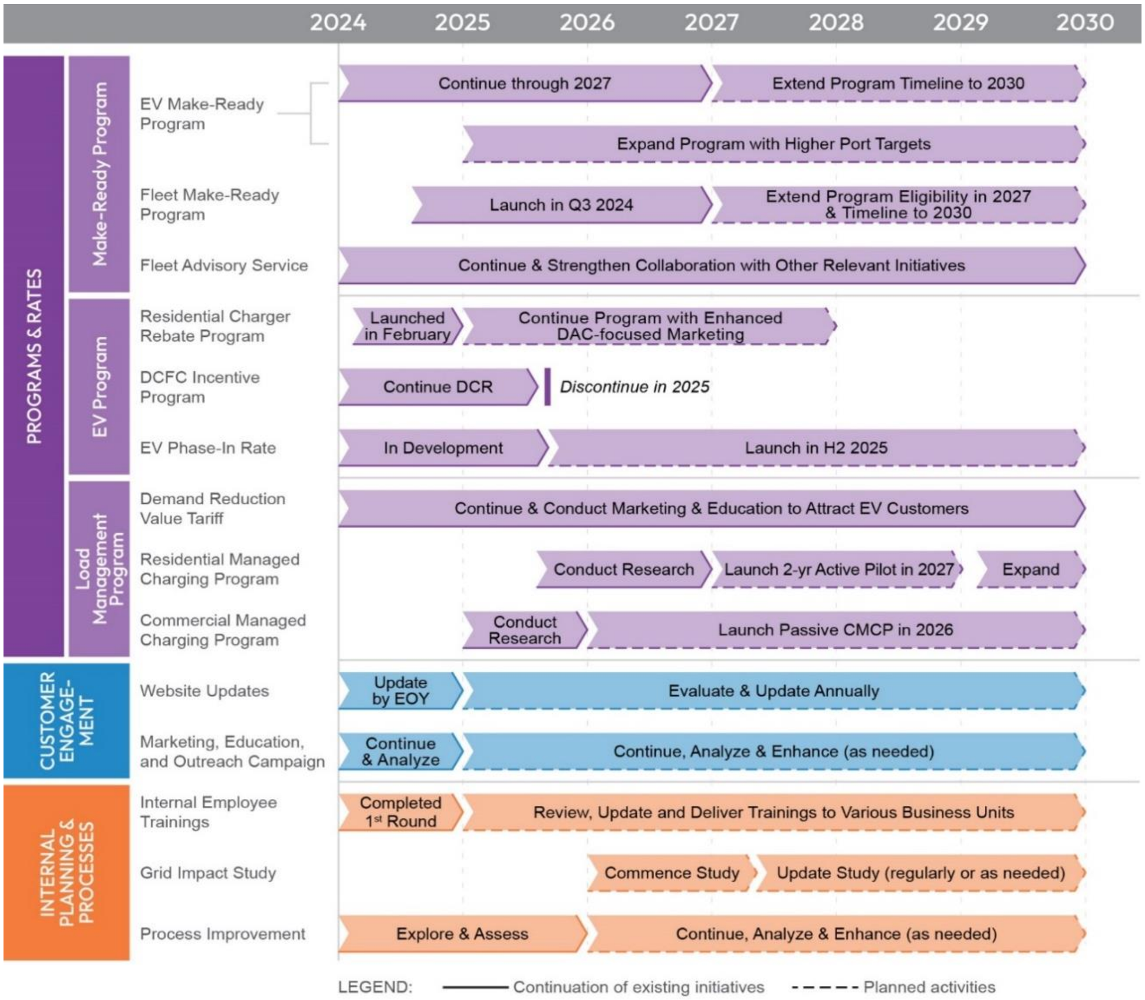
enhance customer experience and engagement. This includes customer insight, sales and technical management, process integration, and analytics and metrics. Overall, CRM tools streamline internal processes and collect customer data to empower employees with a consolidated information repository on customer interactions to enhance customer support. CRM tools would enable PSEG Long Island to utilize a consolidated interface to track key contacts and stakeholder interactions for improved customer support.

4. **Customer Enablement Tools:** PSEG Long Island will investigate the need for customer enablement tools that empower customers to take more direct action by utilizing personalized content. Customers would be better equipped with knowledge, tools, and resources to best leverage EV programs. This could include contractor portals with program-specific resources to accelerate the development process. For PSEG Long Island, customer enablement tools could make it easier for marketing to distribute customer-facing content. PSEG Long Island will evaluate the need for these tools moving forward.
5. **Internal Program Trainings:** The TE Team will continue to offer internal training to teams within PSEG Long Island so that employees are educated on EVs to offer an optimal customer experience. While the first round of training will be completed by 2024, the TE Team will continue educational outreach efforts after 2025. For optimal training effectiveness, the TE Team will annually review and refresh training materials to capture feedback, program updates and determine refresher training needs. This includes the continued use of internal communication channels to raise awareness of EV programs and initiatives. The TE Team will also continue to utilize employee networks with key impacted stakeholders to share pertinent information in a timely manner and discuss defined topics around promotional content development and customer engagement initiatives. Continuing these education efforts will enable internal teams to effectively relay information to customers about the PSEG Long Island 's EV offerings.

3.3.3.3. Transportation Electrification Five-Year Plan Summary

Figure 3-8 below summarizes PSEG Long Island's Transportation Electrification Five-Year Plan (2025 – 2030), categorized by the three strategic pillars discussed above (Customer Programs & Rates, Customer Engagement, Internal Planning & Processes).

Figure 3-8. Transportation Electrification Five-Year Plan Summary (2025-2030)[128]



3.3.3.4. Five-Year Plan Financial Impact

As part of the five-year planning process, PSEG Long Island identified several programs and initiatives to further the support of EV adoption. The TE Team anticipates a total budget of $230 million to support proposed expansion and new initiatives over the next five years. **Table 3-26** shows the forecasted budget to support these initiatives.

[128] This summary represents PSEG Long Island's current vision for transportation electrification strategic initiatives and is subject to change.

For the EV Make-Ready Program, the proposed budget will increase to be $162 million to support higher port targets of more than 14,000 L2 and DCFC ports from 2025 to 2030. For Fleet Make-Ready Program, the proposed budget will increase to $31 million to enable fleet electrification across private and public fleet customers through 2030. The budget increase also includes supporting the potential implementation of a passive commercial managed charging pilot and/or program in 2026 and an active residential managed charging pilot and/or program in 2027, as well as the expansion of engagement and outreach efforts through 2030.

Table 3-26. Five-Year Forecasted Budget (2025 to 2030)

	2025	2026	2027	2028	2029	2030	Total
	Request	*Forecast*	*Forecast*	*Forecast*	*Forecast*	*Forecast*	
Capital	~$9.3M	~$8.3M	~$10.6M	~$11.8M	~$11.8M	~$11.8M	**~$63.7M**
O&M	~$13.1M	~$20.2M	~$25.1M	~$31.9M	~$37.6M	~$38.4M	**~$166.3M**
Total	**~$22.5M**	**~$28.5M**	**~$35.7M**	**~$43.8M**	**~$49.4M**	**~$50.2M**	**~$230.1M**

Programs and Rates

EV Make-Ready Program

PSEG Long Island proposes to extend the EV Make-Ready Program timeline to 2030 and drastically increase port targets to meet EV infrastructure needs. As a result, PSEG Long Island tripled the Program's overall L2 port target compared to last year's forecast and increased the DCFC port target by almost 50%. This results in 13,652 L2 and 783 DCFC port targets by 2030. **Table 3-27** shows the forecasted increase in L2 and DCFC port targets.

Table 3-27. EV Make-Ready Program Actual and Estimated Pre-Approved Ports by Type (2024 Update)

Port Type	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
	Actual	*Actual*	*Actual*	*Forecast*	*Forecast*	*Forecast*	*Forecast*	*Forecast*	*Forecast*	*Forecast*	
L2	8	185	540	500	573	1,290	1,863	2,484	3,105	3,105	**13,652**
DCFC	0	108	114	68	82	82	82	82	82	82	**783**
Total	**8**	**293**	**654**	**568**	**655**	**1,372**	**1,945**	**2,566**	**3,187**	**3,187**	**14,435**

From 2025 to 2030, the total budget resulting from the increased port targets and extended Program timeline is approximately $162 million. As seen in **Table 3-28**, capital expenses will remain largely steady at nearly $6 million per year as DCFC port installation is not forecasted to increase significantly. O&M expenses are forecasted to grow over $6 million year-over-year to support the drastic increase in L2 port targets.

Table 3-28. EV Make-Ready Program Forecasted Incentive Budget[129]

	2025	2026	2027	2028	2029	2030	Total
	Request	*Forecast*	*Forecast*	*Forecast*	*Forecast*	*Forecast*	
Capital[130]	$5,938,212	$5,938,212	$5,938,212	$5,938,212	$5,938,212	$5,938,212	**~$36M**
O&M[131]	$5,822,354	$13,107,918	$18,928,747	$25,238,330	$31,547,912	$31,547,912	**~$126M**
Total	**$11,760,566**	**$19,046,130**	**$24,866,959**	**$31,176,542**	**$37,486,124**	**$37,486,124**	**~$162M**

Fleet Make-Ready Program

PSEG Long Island proposes to expand program eligibility to include private fleets starting in 2027 and extend program timeline from 2028 to 2030 to enable and further support the deployment of charging infrastructure for both public and private fleets. **Table 3-29** reflects these Program updates. The number of total projects increases from 2025 to 2028 as public fleets are enrolled, and private fleets become eligible to enroll in 2027. Fleet enrollment across project type remains at the same level after 2028.

Table 3-29. Fleet Make-Ready Program Estimated Pre-Approved Projects[132]

Project Type	2024	2025	2026	2027	2028	2029	2030	Total
	Forecast	*Forecast*	*Forecast*	*Forecast*	*Forecast*	*Forecast*	*Forecast*	
Public Fleets	**4**	**8**	**14**	**26**	**37**	**37**	**37**	**163**
Small/Medium (<1,000 kW)	3	6	11	21	30	30	30	131
Large (>1,000 kW)	1	2	3	5	7	7	7	32
Public Transportation	**4**	**7**	**11**	**12**	**12**	**12**	**12**	**70**
Small/Medium (<1,000 kW)	1	2	3	4	4	4	4	22
Large (>1,000 kW)	3	5	8	8	8	8	8	48
Private Fleets	**0**	**0**	**0**	**26**	**37**	**37**	**37**	**137**
Small/Medium (<1,000 kW)	0	0	0	23	33	33	33	122
Large (>1,000 kW)	0	0	0	3	4	4	4	15
Total	**8**	**15**	**25**	**64**	**86**	**86**	**86**	**370**

[129] The forecasted budget is based on pre-approved port forecast to ensure sufficient budget is allocated with understanding that some projects may spillover into the following year.
[130] All USMR + DCFC CSMR
[131] L2 CSMR
[132] Assumes 4 Level 2 ports and 4 DCFC ports per project.

The budget for the Fleet Make-Ready Program is forecasted to increase through 2028 to support the development of new EVSE infrastructure for both public and private fleet customers. The Fleet Make-Ready Program budget totals $31 million from 2025 to 2030 as depicted in **Table 3-30**. Capital expenses are forecasted to increase between $1 million and $2 million a year until 2028 to support the increase in the number of enrolled private fleet projects shown in **Table 3-29**, while O&M expenses are forecasted to remain relatively the same. From 2028 on, the budget will remain steady since there is no changes in the forecasted number of projects.

Table 3-30. Fleet Make-Ready Program Forecasted Incentive Budget

Type	2025	2026	2027	2028	2029	2030	Total
	Request	*Forecast*	*Forecast*	*Forecast*	*Forecast*	*Forecast*	
Capital	$1,470,000	$2,390,000	$4,664,000	$5,896,000	$5,896,000	$5,896,000	**~$26M**
O&M	$471,657	$741,176	$808,556	$808,556	$808,556	$808,556	**~$4M**
Total	**$1,941,657**	**$3,131,176**	**$5,472,556**	**$6,704,556**	**$6,704,556**	**$6,704,556**	**~$31M**

Managed Charging

PSEG Long Island developed a five-year managed charging roadmap for both residential and commercial customers to encourage charging behavior that benefits the grid and the environment, while reducing energy bill impacts for commercial and residential customers:

1. Residential Managed Charging: PSEG Long Island plans on implementing an active residential managed charging pilot in 2027 and a subsequent program for residential customers in 2029 to mitigate the adverse impact of at-home charging on the grid. The TE Team developed an initial budget estimate based on a two-year pilot launching in 2027 with 1,000 pilot participant cap. Following the pilot, PSEG Long Island will analyze data collected and lessons learned to expand the pilot into a full program in the following years. The budget of the residential active managed charging pilot and program includes customer incentives and associated admin costs.
2. Commercial Managed Charging: PSEG Long Island plans on implementing a passive commercial managed charging program (CMCP) in 2026, complimenting the EV Phase-In-Rate. This commercial managed charging program may include peak avoidance and off-peak rebate, consistent with the Joint Utilities. Off-peak rebate program offers an incentive for electricity consumed during off-peak hours, and peak avoidance offers an incentive avoid charging during high-demand events. Based on the lessons learned of the commercial managed charging program, the Team will evaluate the need for a commercial active managed charging program after 2030. **Table 3-31** shows estimated rebate amounts for CMCP.

Table 3-31. CMCP Incentive Estimate by Incentive Type[133]

Incentive Type	Season	Amount	Unit
Peak Avoidance	Summer	5	$/kW
	Winter	1	$/kW
Off-Peak	All-Year	0.02	$/kWh

Table 3-32 outlines the estimated budget for commercial and residential managed charging which assumes that all commercial customers and fleet owners are eligible to enroll in the program, and participation will increase year-over-year. The budget also includes incentives and administrative costs.

Table 3-32. Commercial and Residential Managed Charging Forecasted Budget

Type	2025	2026	2027	2028	2029	2030	Total
		Forecast	*Forecast*	*Forecast*	*Forecast*	*Forecast*	
Capital	--	--	--	--	--	--	--
O&M	--	-$0.9M	~$1.5M	~$2.0M	~$2.6M	~$3.3M	**~$10.2M**
Total	**--**	**-$0.9M**	**~$1.5M**	**~$2.0M**	**~$2.6M**	**~$3.3M**	**~$10.2M**

Customer Engagement

The Marketing, Education, and Outreach budget is forecasted to increase by $200k to be around $350k in order to expand outreach and engagement efforts by strengthening stakeholder partnerships and offering additional decision-making tools and resources to customers.

The marketing budget is expected to be $250k annually for the Make-Ready and EV Programs. In 2025, the TE Team is also planning on procuring an online tool that has a project development focus for commercial customers that can help facilitate project and site evaluation process. The budget is expected to be $100k in 2025. Each year, there is an additional licensing cost that culminates to $50k. The Team may also consider procuring other tools to help customers with their transportation electrification transition in future years. These tools will enable customers to compare vehicles and estimate savings potential based on each customer's unique driving needs.

[133] These incentives are estimated at a high-level based on CMCP incentive amounts offered by the JUs. Incentive amounts in this table are subject to change and intended to be used for Five-year plan budget estimation. Actual CMCP incentive amounts will be calculated using historical, PSEG Long Island specific data during program design.

The total budget from 2025 to 2030, combining marketing efforts and potential tools, is forecasted to be $1.85 million. **Table 3-33** shows the combined budget.

Table 3-33. Engagement and Outreach Forecasted Budget

Type	2025	2026	2027	2028	2029	2030	Total
	Request	*Forecast*	*Forecast*	*Forecast*	*Forecast*	*Forecast*	
Capital	--	--	--	--	--	--	**--**
O&M	~$350,000	~$300,000	~$300,000	~$300,000	~$300,000	~$300,000	**~$1.85M**
Total	**~$350,000**	**~$300,000**	**~$300,000**	**~$300,000**	**~$300,000**	**~$300,000**	**~$1.85M**

Internal Planning & Processes

The TE team identified several efforts to streamline and enhance internal planning and processes to increase customer interaction and improve their overall experience. Such efforts include FTE time to streamline customer request processes, and tools to help manage and enable customer relationship and engagement. There may be software or licensing costs associated with these improvements in the future.

Other Efforts

Over the next five years, PSEG Long Island is continuing to offer several programs, rates, and initiatives that have the same budget as what was requested in 2024. These include the ongoing Fleet Advisory Service under the Make-Ready Program. The EV Program will continue to offer Demand Charge Rebate in 2025, which will be replaced by EV Phase-In Rate in H2 2025, and Residential Charger Rebate Program without any major budget changes. **Table 3-34** shows the budget for these programs.

Table 3-34. Forecasted Budget for Other Activities

Type	2025	2026	2027	2028	2029	2030	Total
	Request	*Forecast*	*Forecast*	*Forecast*	*Forecast*	*Forecast*	
Capital[134]	~$1.9M	--	--	--	--	--	**~$1.9M**
O&M[135]	~$6.5M	~$5.1M	~$3.6M	~$3.6M	~$2.4M	~$2.4M	**~$23.6M**
Total	**~$8.4M**	**~$5.1M**	**~$3.6M**	**~$3.6M**	**~$2.4M**	**~$2.4M**	**~$25.5M**

[134] EV Phase-In Rate development.
[135] NYSERDA EV Prize, Fleet Advisory Service, Demand Charge Rebate, Residential Charger Rebate, admin/labor costs.

4. Energy Storage

2024 Utility 2.0 Plan Annual Filing, Energy Efficiency Plan, and Five-Year Plans

4. Energy Storage

Energy storage enables a variety of advanced grid technologies and is critical to the success of New York State's Climate Act goals. Energy storage helps integrate clean energy onto the grid, increases system efficiency, provides hosting capacity to support integration of more renewables and Distributed Energy Resources (DER), and increases reliability where energy storage is used in place of traditional T&D investments. New York State has some of the most ambitious energy and climate goals in the country, and energy storage will play a crucial role in meeting these goals. In 2022, Governor Kathy Hochul issued a landmark announcement calling for New York to double its energy storage target to 6,000 MW by 2030 to help integrate significant new volumes of variable renewable energy resources to the grid.

PSEG Long Island supports the Climate Act's goals and the recommendations set forth in the New York 6 GW Energy 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. PSEG Long Island's initiatives (both inside and outside of the Utility 2.0 Program) address different use cases: distribution system, bulk system, and customer sited. For the next five years, PSEG Long Island aims to pursue a least-cost storage portfolio through 2030 (see the Energy Storage Five-Year Plan below).

Presently, PSEG Long Island has two front-of-the-meter (FTM) storage systems with a total capacity of 10 MW/80 MWh on the South Fork. In 2021, PSEG Long Island issued an RFP for Bulk Energy Storage that was initially expected to be in service by December 31, 2025, and is now anticipated to be in service by December 31, 2028, due to supply chain delays and other procurement risk factors. Beyond utility-scale storage, PSEG Long Island supported customer-sited energy storage through its behind-the-meter (BTM) Storage Plus Solar Program that was completed in 2021. This project directly supported the New York 6 GW Energy Storage Roadmap's recommendation of leveraging market incentives to accelerate adoption of customer-sited storage, including storage paired with solar PV.

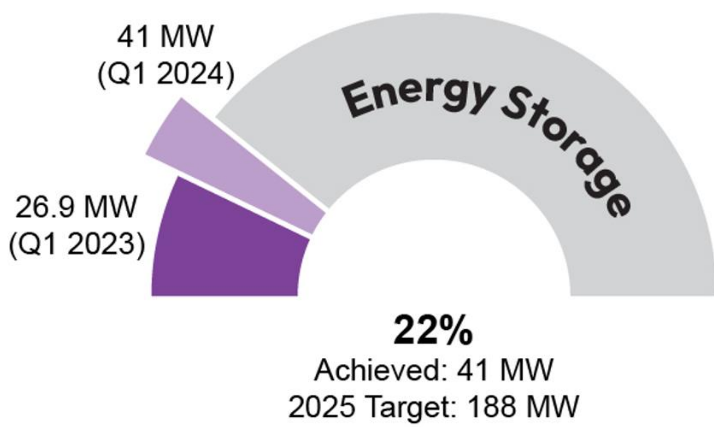
Initiatives included in this chapter contribute to New York State's energy storage goal in different ways. The Connected Buildings Pilot (**Section 4.2.1**) deploys smart electric panels within residential buildings for ease of solar PV and energy storage integration. Additionally, this pilot provides insight into circuit-load energy usage that results in contributions to the state's solar and storage goals. Through the Residential Energy Storage System Incentive Program (**Section 4.2.2**), energy storage adoption is promoted through utility incentives that are available for Long Island single-family residential customers. This program is uniquely capable of supporting DERs by storing solar generation and utilizing it during critical peak demand periods.

Chapter Contents

4.1. 2025 Goal Achievement

New York State's 2025 statewide CLCPA goal for energy storage is 1,500 MW.[136] PSEG Long Island has voluntarily committed to a portion of the New York State Energy Storage CLCPA Goal, which is determined by the Utility's 12.5% load-share-ratio (188 MW). In 2018 and 2019, 10 MW (total) of FTM energy storage was installed at East Hampton and Montauk on the South Fork, respectively. As of March 2024, approximately 31.4 MW of BTM energy storage has been connected to the system from installed retail (~11.3 MW) and residential (~20.1 MW) applications. It is expected that approximately 2.8 MW of additional energy storage (~555 systems) will be added to the system on the residential side by the end of 2026. Thus, PSEG Long Island expects to achieve its share of the 2025 CLCPA goal for energy storage in 2028, pending the finalization of the 179 MW Bulk Energy Storage Request For Proposal (RFP).[137] Energy Storage 2025 Goal Achievement is depicted in **Figure 4-1.**

Figure 4-1. Energy Storage 2025 Goal Achievement



[136] New York State Climate Action Council. Scoping Plan – Full Report December 2022.

[137] The current expectation (as of July 1, 2024) is that the 179 MW BESS RFP will be in-service by the end of 2028, but this is heavily dependent on the resolution of supply chain, import tax, and community storage moratorium complications, which are outside of the Utility's control.

Table 4-1. PSEG Long Island Energy Storage Project Portfolio

Type	Category	Size (MW AC)	In-Service (Est./Act.)
Residential	BTM: Long Island Energy Storage (as of March 2024)	~20.1	2024
Residential	BTM: Utility 2.0 Residential Energy Storage System Incentive Program (*238 systems*)	~1.2	2025
Retail	BTM: Long Island Energy Storage (as of March 2024)	~11.3	2024
Utility-Scale	FTM: East Hampton & Montauk	10	2018 & 2019
All Energy Storage	**Total Expected MW (by EOY 2025)**	**42.6**	2025
All Energy Storage	**Long Island's 2025 CLCPA Load-Share Ratio Target**	**188**	2025
Residential	BTM: Utility 2.0 Residential Energy Storage System Incentive Program (*317 systems*)	~1.6	2026
Bulk	Bulk Energy Storage System (BESS) (2023 RFP Pending)	179	2028
All Energy Storage	**Total Expected MW (by EOY 2028)**	**223.2**	2028

Note: FTM = Front-of-the-Meter; BTM = Behind-the-Meter

4.2. Energy Storage Utility 2.0 Initiatives and Programs

4.2.1. Connected Buildings Pilot

2024 Status	Active
2025 Status	Active
Start Year	2023
Funding Approved Through	2025
Description and Justification	The Connected Buildings Pilot demonstrates how consumption control can help provide customers with bill savings, adds grid value through reduced supply and infrastructure costs, and supports beneficial electrification. This initiative launched in 2023 and is expected to run through 2024 with the final report delivered in 2025.

The Connected Buildings Pilot demonstrates 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., energy 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.

4.2.1.1. Implementation Update

Due to contracting delays in 2022 and 2023, the Connected Buildings Pilot is projected to be completed by the end of 2024, with a final report being issued in 2025. 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. Throughout the duration of the pilot, SUNation customers have not been adopting the panel solution as quickly as anticipated, which has caused a decreased level in activity of customer uptake compared to initial estimates. Minimal activity for the pilot occurred in 2022 due to contracting delays with the third-party contractor and vendor. Additionally, contracting finalization tasks in 2023 caused delays further down the entire project line.

To exercise the capability of the panels, customers generally are sought who have at least two or more of the following equipment: PVs, EV charger, on-site storage or heat pump. While using this criterion seemed reasonable for having 75 panels installed during the first six months of 2023, PSEG Long Island was informed by the partnered PV contractor that market conditions changed uptake patterns, especially with on-site storage. Specifically, changes in interest rates and fees, lending patterns resulting from bank failures in early 2023, and continued price increases resulted in a dampening of customer uptake. This has been the major contributing factor that delayed progress on planned installations in 2022 and early 2023. In late 2023 and early 2024, the cost of storage equipment started to reduce and the voluntary enrollment option for Time-of-Day (TOD) rates helped to progress panel installations for the pilot program. Given delays in the overall program as a result of low customer adoption early on in the program and other contracting delays, additional testing will be needed in 2025 once all 75 SPAN Smart Panels are installed and interconnected. Currently, it is estimated that all 75 panels will be installed and interconnected with rebate payments paid by the end of 2024.

Schedule Update

Through April 2024, 64 participants have been pre-approved, 46 projects have been completed, and all (75) panels are committed to projects. The installation, activation, and collection of data from the remaining SPAN panels is expected to occur by the end of 2024.

The data sharing agreement with SPAN has been finalized and panel data is accessible to PSEG Long Island. The team is awaiting the submission of the remaining applications in order to pre-approve the final Pilot participants. A Mid-Term Report for the Pilot was developed in Q1 2024, which provides initial findings and a preliminary analysis for the pilot program. Following the installation of the final panels, testing scenarios (e.g., metering and demand flexibility) will begin in the summer / fall of 2024 and are expected to be completed by the end of November 2024. Rebate payments will be paid out to participating customers by the end of 2024. After completion of the pilot demonstration, a Final Report will be developed one year following the Mid-Term Report (Q1 2025).

Risks and Mitigations

Table 4-2. Risk and Mitigation Assessment – Connected Buildings Pilot

Category	Risk	Mitigation
Customer Data	Inability to access customer data	Develop alternative access approach or have them send flat files of consumption data
Installation Target	Completion of all 75 installations by the end of Q2 2024	Work with SUNation and SPAN to ensure that schedule is established and monitored to meet deadline
Customer Engagement	Demonstrated completion of customer enrollment, device activation, and utility receipt of data for 75 customers by the end of 2024	Continue to work closely with SUNation and SPAN to ensure the timely completion of all panel installations for the pilot

4.2.1.2. Funding Reconciliation and Request

The Connected Buildings Pilot had no budgetary spend in 2022 due to contractual delays with the third-party contractor and vendor. Additionally, in 2023, increased interest rates coupled with contractual delays pushed rebate payments to be paid out by the end of 2024. Because of these delays, the pilot completion date has shifted from the end of 2023 to Q2 2025. Thus, the O&M spend that was planned for this pilot in 2023 is now expected to be spent in 2024 and 2025. Please see the budget adjustments listed below:

- **Rebates**: Identified and recruited customers are 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. As a result of continued poor SPAN Smart Panel customer uptake in 2023, SUNation estimated that an increase in incentive value would help increase customer adoption. The $300 increase in the rebate/unit value has proven to be effective in attracting customers, thus, the rebate value has been increased to $3,800/unit for new participants in the pilot program. PSEG Long Island expects that all rebate payments will be made by the end of 2024. Rebate payments will not be offered beyond 2024.

  - Initial Rebate Offering: $3,500 rebate/Smart Panel x 18 Smart Panels = $63,000
  - Updated Rebate Offering: $3,800 rebate/Smart Panel x 57 Smart Panels = $216,600
    - 2023: $42,000
    - 2024: $237,600

- **Evaluation**: Third-Party support will be required to aid in the analysis of data for the Final Pilot assessment report. Given that all 75 SPAN Smart Panels are expected to be installed and interconnected in Q4 2024 and that the Final Pilot Assessment Report will require at least 12 months of data before it can be completed, the third-party support required to develop the Final Pilot Assessment Report cannot be begin until 2025.
  - Estimated $20,000 for 2025
- **Customer Incentives**: Participating customers will be offered opportunities in the Summer/Fall of 2024 and 2025 to participate in incentive offerings to partake in testing scenarios for the SPAN Smart Panels. These testing scenarios will examine the different capabilities of the SPAN Smart Panels and help ensure that they are working properly. Data from the testing results will be used for the Final Pilot Assessment Report.
  - Estimated $20,000 in 2024; $20,000 in 2025

In the 2023 Utility 2.0 Plan, the team erroneously included $74,500 in the 2024 budget for IT and Marketing and Outreach efforts, which was also summarized in the 2023 DPS Recommendation Letter. With the data sharing agreement in place, the Connected Buildings team will no longer need IT support to collect and analyze data. Furthermore, the pilot does not require any Marketing and Outreach funding as this activity is conducted by SUNation as a part of their existing interaction with the customers.

In last year's Utility 2.0 Plan, it was anticipated that all 75 SPAN Smart Panels would be installed by the end of 2023. However, due to increased interest rates coupled with contractual delays, the rebate payments will be paid out by the end of 2024. As mentioned above, the initial rebate value of $3,500/unit has been updated to $3,800/unit for new applicants in 2024 to help increase customer adoption into the pilot program.

The updated annual budget and variance are shown in **Table 4-3** and **Table 4-4**. It is important to note that budgetary values presented in the tables below are rounded to the hundredths decimal place.

Table 4-3. Capital and Operating Expense Budget, Actual and Forecast ($M)

	Actual ($M) 2023	Updated Forecast ($M) 2024	Request ($M) 2025	Projected (Not Requested) ($M) 2026	Total ($M)
Capital	-	-	-	-	-
O&M	0.04	0.26	0.04	-	0.34
Total	**0.04**	**0.26**	**0.04**	**-**	**0.34**

Table 4-4. Capital and Operating Expense Variance

	2023 ($M)	2024 ($M)	2025 ($M)
Capital	-	-	-
O&M	(0.25)	0.20	0.04
Total	**(0.25)**	**0.20**	**0.04**

4.2.2. Residential Energy Storage Incentive Program

2024 Status	On Hold
2025 Status	Active
Start Year	2025
Funding Approved Through	2026
Description and Justification	The Residential Energy Storage System Incentive Program is an extension of the Behind-the-Meter (BTM) Solar plus Storage program that was proposed and approved in the 2018 Utility 2.0 Plan. This program will leverage the existing Long Island Single-Family Residential Incentive that is currently funded by NYSERDA. PSEG Long Island will make Block 3 of the incentive funding available to customers once the replenished NYSERDA incentive Block 2 expires.

PSEG Long Island plans to initiate 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[138] customers) installing ESS paired with new or existing solar.

The Long Island Single-Family Residential Block 2 Incentive funded by NYSERDA was expected to become fully allocated in May 2024. However, NYSERDA offered to continue the Block 2 Incentive by replenishing the block with an additional $600,000 in funding with the contingency that PSEG Long Island continues funding the program once the additional $600,000 is fully allocated. Based on the current incentive payout rate at approximately $60,000 incentive payments per month, it is expected that the PSEG Long Island Block 3 incentive will likely begin in Q2 2025. If the additional NYSERDA funding is allocated earlier or later than expected, PSEG Long Island is prepared to immediately initiate its Block 3 incentive. Following the full allocation of PSEG Long Island's Block 4 (expected by the end of 2026), NYSERDA intends to replenish this block with an addition $400,000 in funding. Thus, NYSERDA intends to contribute an additional $1 million in funding for this program in 2024 and likely in 2026/2027.

PSEG Long Island's Block incentive structure is designed based on NYSERDA's current residential Block Incentive Program. The incentives will be available for PSEG Long Island's residential customers and will be placed on a declining block structure based upon a per kWh of usable installed capacity, with higher incentives for LMI/DAC customers, totaling $1.5 million. Since contractors are already knowledgeable about this incentive structure, it will help create a seamless transition for the program.[139,140] The block structure is also designed to incentivize residential customers to take advantage of the incentive in order to receive the greatest monetary benefit and not wait to apply.

4.2.2.1. Implementation Update

See the scope and schedule updates below for Residential Energy Storage System Incentive 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 anticipates making an additional $1.5 million in funding for incentives available likely starting in Q2 2025. When the project was approved to start in 2023, the incentive payment rate for NYSERDA's NY Sun Program at the time was approximately $100,000 per month. However, in 2023 the

[138] NYSERDA's definition on Low- to Moderate-Income (LMI) and Disadvantaged Communities (DAC) will be used. See additional information on the definition of LMI and DAC.
[139] NYSERDA Energy Storage Incentive Dashboard
[140] NYSERDA Incentives for Long Island Residents

incentive payment rates slowed to approximately $68,000 per month and are currently at about $60,000 per month in 2024. As a result of slow customer adoption over the past two years, PSEG Long Island does not expect to run through the entire $1.8 million in incentives (as approved in the 2023 Utility 2.0 Plan) during the 18-month enrollment period for the program. Thus, PSEG Long Island has reduced the incentive request to $1.5 million total for 2025 through 2026 (see the *Funding Reconciliation* Section below for more details).

The first block incentive (Block 3) offers a $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 (Block 4) offers lower incentives: $150 per kWh and $300/kWh for non-LMI/DAC and LMI/DAC customers, respectively. **Table 4-5** shows the proposed incentives by block.

Table 4-5. Incentive Rates by Block

Block	Available Funding	Non-LMI/DAC	LMI/DAC
1	$750,000	$200/kWh	$400/kWh
2	$750,000	$150/kWh	$300/kWh

Based on the declining Block incentive structure, PSEG Long Island now expects to enroll a total of approximately 555 systems through the program, assuming an average battery capacity of 5kW/15kWh. **Table 4-6** outlines expected systems by customer segment and block.

Table 4-6. Expected System Enrollment by Block

Segment	Block 3	Block 4	Total
Non- LMI/DAC	225	300	525
LMI/DAC	13	17	30
Total	238	317	555

In order to be eligible for the Residential Energy Storage System Incentive offered by PSEG Long Island, residential customers' storage systems must be paired with solar PV 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.[141] 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.

LMI and DAC Customers

To qualify for the LMI/DAC program incentive based on income eligibility, contractors must also complete the NYSERDA Income Eligibility Form and upload relevant documentation to demonstrate the customer's income eligibility.[142] The Income Eligibility Form that will be used for PSEG Long Island's Residential Energy Storage System Incentive Program is the same form that is used for NYSERDA's Affordable Solar Residential Incentive program.

There are various forms of documentation that can be provided by the contractor and circumstances to verify if a customer qualifies as LMI:

- If the customer qualifies for NYSERDA's Affordable Solar Incentive, then the customer will also qualify for the higher LMI/DAC program incentive.

[141] While all systems enrolled in the new Residential Storage Incentive Program must enroll in the DLM tariff to be eligible for the incentive, not all systems enrolled in the DLM tariff participate in the incentive program.
[142] NYSERDA's Income Eligibility Customer Submission Form

- If the customer is currently enrolled in other LMI rate classes (e.g., PSEG Long Island's Household Assistance Rate Program), then the customer will also qualify for the higher LMI/DAC program incentive.
- If the customer has been participating in at least one of the following programs in the last 12 months, then the customer will also qualify for the higher LMI/DAC program incentive:
    - Home Energy Assistance Program (HEAP)
    - Medicaid
    - Supplemental Nutrition Assistance Program (SNAP)
    - Family Assistance (FA)
    - Safety Net Assistance (SNA)
    - Temporary Assistance for Needy Families (TANF)
    - Supplemental Security Income (SSI)
    - Veteran's Pension or Veteran's Surviving Spouse Pension

On March 27, 2023, the Climate Justice Working Group (CJWG) finalized the DAC criteria. Communities meeting the criteria can now be identified with an interactive DAC map on the NYSERDA website.[143] A list of census tracts that meet the DAC criteria is also now publicly available.[144,145] PSEG Long Island follows this DAC criteria to identify single-family residential Long Island customers within DACs that are eligible for the higher LMI/DAC Incentive.

In Q2 2024, NYSERDA also announced that an additional incentive of $150/kWh is available for residential solar projects paired with energy storage that meet the requirements of the Affordable Solar Residential Incentive for LMI homeowners.[146] The energy storage paired with solar PV project must be approved for the Affordable Solar Residential Incentive to receive the add-on incentive.

Schedule Update

Now that NYSERDA has committed to replenish Block 2 of their incentive funding with an additional $600,000, it is expected that PSEG Long Island's Residential Energy Storage

[143] NYSERDA's Disadvantage Community (DAC) Map
[144] List of Census Tracts that meet the Disadvantaged Community Criteria
[145] Additional detail on DAC Criteria can be found on the Climate Act Website under the "Disadvantaged Communities Criteria Documents" section.
[146] NYSERDA NY-Sun Upstate + Long Island Program Manual – April 2024 Update, pg. 19

System Incentive will start in Q2 2025. Thus, the 18-month program enrollment period is expected to be completed in Q3 2026 with all incentive payments expected made by the end of 2026. However, there is an approximate three-month lag in the time a contractor submits their customer's application for the incentive to the time the project is installed, and PSEG Long Island issues the incentive. So, if contractors enroll during the final enrollment month of the program it is possible that payments may extend into 2027. As mentioned above, NYSERDA also intends to replenish Block 4 with an additional $400,000 once all PSEG Long Island Block 4 incentives have been distributed.

Due to reduced customer adoption of ESS, it is also possible that the enrollment period for the program is extended beyond 18 months and into 2027. Prior to next year's Utility 2.0 Plan, PSEG Long Island will examine the remaining block incentive funds and 2024 ESS adoption rates to determine whether or not the program will need to be extended beyond 2026.

Since enrollment is expected to begin in 2025, the project team will continue to support contractors in the transition to the new incentive program by educating contractors (and associated customers) about the funding availability, new incentive structure, and eligibility requirements.

Customer acquisition is driven by participating contractors and supported by PSEG Long Island. PSEG Long Island supports contractors through the various marketing and outreach tactics listed below:

- **Website[147]:** Informative webpage on the PSEG website for both contractors and customers regarding the new program
- **Digital Brochures / Billing Inserts:** Billing inserts and a digital brochure that can be printed for use by distributors to generate contractor interest
- **Press Releases:** Press releases to engage the media and disseminate information on where to find more details on the program
- **Video:** Marketing video to educate customers on the benefits of Solar and Battery storage, as well as the program itself
- **Social Media:** Digital campaigns that target potential energy storage program participants, such as LMI/DAC customers and customers with existing battery

[147] Information on the Residential Energy Storage System Incentive Program has been added to the PSEG Long Island Website – Solar Plus Battery Storage landing page.

storage systems installed but not enrolled in the PSEG Long Island battery storage program

- **Email:** Email blasts to inform PSEG Long Island residential customers of new storage incentive program
- **Search Engine Optimization (SEO):** Search Engine Optimization to enable more effective internet searches
- **Search engine marketing (SEM):** Search engine marketing to ensure visibility of PSEG Long Island's program as potential customers research options and programs on the internet.

Risks and Mitigations

Table 4-7. Risk and Mitigation Assessment – Residential Energy Storage Program

Category	Risk	Mitigation
Customer Adoption	Residential customer adoption of energy storage on Long Island reduced in 2023 likely due to the rising costs of battery storage systems coupled with increased interest rates. Reduced customer adoption pushed back the launch of the PSEG Long Island Residential Energy Storage System Incentive Program from September 2023 to April 2025. It is possible that reduced adoption rates could continue for the next few years, which could also impact the incentive funding requirements for the program.	PSEG Long Island will continue to support the local industry through the Residential Energy Storage System Incentive Program Marketing Plan to promote battery storage adoption on Long Island. In comparison to other New York Utilities and their customers served, PSEG Long Island has the highest residential energy storage adoption rate (as of March 2024).
Storm Duty	Storm duty takes priority over everything, including project work. So, 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. Request additional time for the delivery of the project, if needed.
Demand Response	After receiving the upfront incentive and being enrolled in the demand response 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.

4.2.2.2. Funding Reconciliation and Request

Due to the pushed back start date of PSEG Long Island's Residential Energy Storage System Incentive Program, the associated $1.5 million in O&M incentive funding break out by year has been adjusted to align with the program's new anticipated 2025 through 2026 timeline (and potentially 2027 depending on any rebate processing lag time).

Given the total incentive funding and 18-month enrollment period for the program coupled with the planned marketing initiatives for the program, the estimated run-rate is expected to fall between $66,000 and $100,000 (~$83,000 average) in incentive payments per month. PSEG Long Island anticipates that the implementation of a robust Marketing Plan will help bolster the incentive run-rate over the timeline of the program. However, it is possible that incentive payments could extend beyond the 18-month enrollment period if adoption rate expectations do not pan out and incentive funding is still remaining.

Thus, PSEG Long Island is requesting $600,000 in O&M incentive funding for 2025 and is projecting $900,000 in incentive funding for 2026. This is a result of the pushed back start date for the program due to slow customer adoption and NYSERDA's Block 2 funding supplementation, which will last likely until the end of Q1 2025 (based on current run-rate).

During next year and the following year's annual filing process, more data will be available to determine whether or not any additional funding will need to be requested for 2027 or any remaining funding from Block 4 will need to be shifted into 2027. Please see the budget adjustments listed below:

- **Upfront Customer Incentives**: Approved participating single-family residential Long Island customers (DAC / LMI and non-DAC / LMI customers) in the Residential Energy Storage System Incentive Program receive a rebate incentive to reduce the upfront cost of their ESS (see the 'Scope Update' Section for more details on the incentive structure for different customer groups). Participating contractors are responsible for enrolling customers into the incentive program.
  - Estimated $0.75 million/incentive block x 2 incentive blocks = $1.5 million total
    - 2023 and 2024: $0 as a result of reduced customer adoption and NYSERDA's $600,000 Block 2 supplementation in 2024
    - 2025: $66,666 estimated incentives/month x 9 months[148] = $600,000

[148] $600,000 for 2025 or ($66,666 per month) was estimated based on the average incentive run-rate from 2023 and 2024 for NYSERDA's NY Sun Program.

        - 2026: $100,000 estimated incentives/month x 9 months[149] = $900,000

- **Marketing and Outreach**: Customer acquisition is driven by participating contractors and supported by PSEG Long Island. PSEG Long Island supports contractors through various marketing efforts and outreach tactics (see the 'Schedule Update' Section for more details on the various marketing tactics). Due to the pushed back start/end enrollment dates for the program, ongoing marketing and outreach efforts will occur until the end of Q3 2026.
    - Estimated $127,560 total
        - 2023: $37,560 for Marketing Video
        - 2025: $45,000 for all Marketing activities mentioned in the 'Schedule Update' Section above
        - 2026: $45,000 for all Marketing activities mentioned in the 'Schedule Update' Section above (minus the Printed Brochures)

The updated annual budget and variance are shown in **Table 4-8** and **Table 4-9**. It is important to note that budgetary values presented in the tables below are rounded to the hundredths decimal place.

Table 4-8. Capital and Operating Expense Budget, Actual and Forecast ($M)

	Actual ($M) 2023	Updated Forecast ($M) 2024	Request ($M) 2025	Projected (Not Requested) ($M) 2026	Total ($M)
Capital	-	-	-	-	-
O&M	0.04	-	0.65	0.95	1.64
Total	**0.04**	**-**	**0.65**	**0.95**	**1.64**

Table 4-9. Capital and Operating Expense Variance

	2023 ($M)	2024 ($M)	2025 ($M)
Capital	-	-	-
O&M	(0.27)	(1.54)	0.50
Total	**(0.27)**	**(1.54)**	**0.50**

149 $900,000 for 2026 or ($100,000 per month) was estimated based on a potential increase in customer adoption that could result from PSEG Long Island's robust marketing initiatives and changing market conditions. However, increased adoption is not a certainty, so the enrollment period for the program may be extended into 2027. In 2025 and 2026, PSEG Long Island will examine the remaining block incentive funds and overall 2024 ESS adoption rates to determine whether or not the program will need to be extended into 2027.

4.2.2.3. Performance Reporting

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

- **Numbers 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[150] for LMI/DAC customers are effective in increasing participation for ESS.
- **Utility Funds Committed** – Track the funds committed to assess the total program costs.

Once PSEG Long Island's Residential Energy Storage System Incentive Program launches, data for the metrics listed above and calculated benefits will be tracked and collected.

Reforecasted Business Case

In 2024, the original Benefit Cost Analysis (BCA) for the Residential Energy Storage System Incentive Program was reforecasted to account for timeline changes, $1.5 million in approved incentives rather than $2 million as originally proposed or the $1.8 million as approved, and the change in projected system enrollments as a result of the anticipated pushed back start date of the program to Q2 2025.

Benefit streams considered include net non-energy benefits, avoided outage costs, avoided energy (LBMP), avoided generation capacity cost (AGCC), avoided transmission capacity infrastructure, net avoided CO_2, and avoided distribution capacity infrastructure. The benefits are largely driven by avoided outage costs, which consider the avoided costs associated with acquiring a home backup generator in the event of an outage. The reforecasted analysis assumes that approximately 555 systems (average battery capacity of 5kW/15kWh) would enroll in the program and contribute to benefits, rather than an initially estimated 850 systems in the original BCA.

Program costs include program administration costs and participant DER costs. The participant DER cost represents the majority of total program costs, consisting of the hardware and installation cost of the storage system.

Based on the above, the reforecasted Residential Energy Storage System Incentive Program BCA has a societal cost test (SCT) benefit-to-cost ratio (BCR) of 0.67. For comparison, the SCT BCR in the original BCA was 0.39. This increase in the SCT BCR can

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[150] For example, Block 3 Non-LMI/DAC incentive: $200/kWh; Block 3 LMI/DAC incentive: $400/kWh. See additional information in the 'Scope Update' Section above.

be attributed to the addition of the Net Avoided CO_2 value stream incorporated into the reforecasted BCA and the 8% increase in the Investment Tax Credit[151] from 2022 to 2023 (22% to 30%). The net present value (NPV) of the resulting cost and benefit streams from the SCT in the BCA are shown in **Figure 4-2** below.

The largest cost drivers are attributed to the participant costs of the systems, as the hardware and installation costs of energy storage systems remain high. For example, in 2018 when PSEG Long Island filed the original BTM Storage plus Solar PV the program battery storage costs were approximately $500/kWh by 2022; however, actual program enrollment data shows that system costs are presently $950/kWh on average.

Although the original SCT BCR of 0.39 was unfavorable, the Residential Energy Storage System Incentive Program was ultimately approved by LIPA following the 2022 Utility 2.0 Plan since the program helps to ensure the following:

- **Statewide Clean Energy Targets:** Support statewide energy storage targets of 1,500 MW by 2025 in New York State and 188 MW by 2025 in Long Island
- **Leveraged Investment:** Stimulate third-party investment alongside public and utility investments and promote market competition at scale
- **Upfront Financing Support**: Remove barriers to energy storage adoption due to soft costs

Additionally, battery storage offers many non-energy benefits that are not presently assigned an economic value so by default they are valued at zero in the benefit-cost analysis. Examples of non-energy benefits include, but are not limited to[152]:

- **Property values**: Increased property values due to added resiliency and increased leasable space
- **Avoided safety-related emergency calls**: Reduced risk of emergencies associated with power outages
- **Job creation**: Creates jobs in engineering and research & development among others
- **Less land used for power plants**: Makes available land for other uses besides peaker plants

Furthermore, energy storage is a unique technology that can reduce peak demand or peak shifting on demand that cannot be effectively achieved with traditional, passive efficiency measures, but it can be achieved with battery storage. As more renewables come onto the

[151] Inflation Reduction Act Tax Credit Opportunities for Energy Storage
[152] Clean Energy Group. Energy Storage: The New Efficiency. April 2019.

electric grid, the ability to shift peak loads becomes more important and valuable. As solar generation begins to decline in the early evening hours, there is a drop in energy supply, however, demand for electricity continues to increase due to customers coming home from work and turning on their air conditioners and other appliances. This will be exacerbated by accelerated deployment of electric vehicles which if left unmanaged, will further increase peak demand. It continues to be important that PSEG Long Island deploy battery storage technology for peak shaving capabilities before this becomes an issue.

With a diverse fuel mix, New York State also suffers from what is called the "tale of two grids"[153], meaning that the fuel mix in upstate New York is much cleaner than the fuel mix in New York City and Long Island. Upstate New York consists mainly of hydropower, wind and solar, where Long Island and New York City hosts the majority of fossil fuel generation in the state. Deploying battery storage paired with solar for peak shaving capabilities will reduce the need for fossil fuel peaker plants on Long Island. Although not reflected in the BCA, this also results in greater environmental benefits through reductions in GHG emissions due to the fact that battery storage is reducing the need for, peaker plants to operate as often on Long Island. Although they typically only operate for a small number of hours per year, these peaker plants produce twice the carbon emissions and twenty times the NOx emissions per unit of energy generated as compared to a typical thermal plant[154].

Some fossil fuel peaker plants may be located in DACs causing air pollution to predominantly affect lower income residents in the area. Therefore, lowering peak demand through use of residential battery storage paired with solar will help provide cleaner air to low-income residents and those that reside in a DAC.

Even though the reforecasted benefit-to-cost ratios for the Residential Energy Storage System Incentive Program are still below 1.0 (SCT = 0.67, UCT = 0.86, RIM = 0.47), PSEG Long Island believes that energy storage can be cost-effective for its customers and society. As costs fall and energy storage becomes more economically attractive over time, PSEG Long Island can use lessons from this program to help accelerate the energy storage market.

As the program progresses, PSEG Long Island intends to track costs of the storage systems participating in the program on an ongoing basis and evaluate whether incentive levels should be adjusted.

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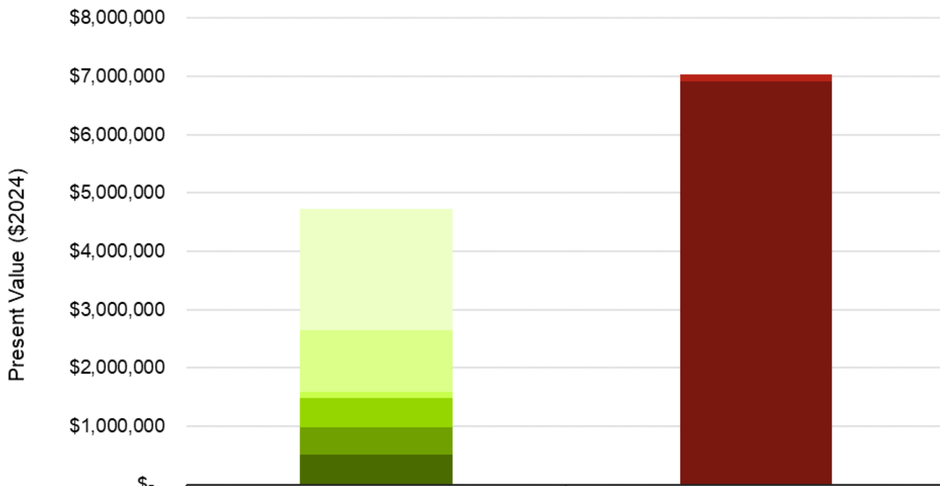
[153] The New York ISO & Grid Reliability, February 2021 report
[154] Energy Storage Roadmap, 2018

Figure 4-2. Residential Energy Storage System Incentive Program Present Value Benefits and Costs of SCT



	Benefits	Costs
Net Non-Energy Benefits	$2,075,946	$-
Avoided Outage Costs	$1,053,779	$-
Avoided Energy (LBMP)	$118,073	$-
Avoided Generation Capacity Cost (AGCC)	$490,184	$-
Avoided Transmission Capacity Infrastructure	$467,609	$-
Avoided Distribution Capacity Infrastructure	$523,838	$-
Program Administration Costs	$-	$116,499
Participant DER Cost	$-	$6,919,820
Total	$4,700,676	$7,036,318

Table 4-10. Residential Energy Storage Incentive Program Value Streams

#	Value Stream	Calculation Methodology	Benefits (NPV, $M)	Costs (NPV, $M)
1	Avoided Distribution Capacity Infrastructure	Based upon marginal capacity costs and estimated peak demand reduction	0.52	
2	Avoided Transmission Capacity Infrastructure	Based upon marginal capacity costs and estimated peak demand reduction	0.47	
3	Avoided Generation Capacity Cost (AGCC)	Based upon marginal capacity costs and estimated peak demand reduction	0.49	
4	Avoided Outage Costs	Calculated by valuating the avoided cost of acquiring a home backup generator	1.05	
5	Net Non-Energy Benefits	Includes Investment Tax Credit (ITC) applied to upfront storage system costs (30%)	2.08	
6	Avoided Energy (LBMP)	Assume 85% customer enrollment in TOD rates and 15% enrollment in Rate 180	0.12	

#	Value Stream	Calculation Methodology	Benefits (NPV, $M)	Costs (NPV, $M)
7	Net Avoided CO_2	Accounts for the avoided CO_2 emissions during on- and off-peak hours for enrolled systems, the Value of E for PSEG Long Island Service Territory, and annual energy % losses	-0.03[155]	
8	Participant DER Cost	Accounts for participant cost of energy storage system hardware and installation cost		6.92
9	Program Administration Costs	Includes costs for customer outreach and marketing		0.12
	Total Benefits		**4.70**	
	Total Costs			**7.04**
	SCT Ratio		**0.67**	

NPV = Net present value

4.2.2.4. Lessons Learned

Since the start date of this incentive program is dependent on when the current NYSERDA incentive program expires, the team has 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. Additionally, changes in customer adoption as a result of changes in battery storage costs and interest rates can have unplanned impacts on programs, such as this incentive program, that rely heavily on customer education, interest, and purchasing habits.

Over the course of a few months in 2023, multiple fire safety incidents occurred at energy storage facilities across New York, which seriously tarnished the public perception of utility-scale storage and battery storage in general.[156] Following these incidents, a group of state agencies formed the Inter-Agency Fire Safety Work Group to mobilize personnel and resources necessary to keep New Yorkers safe. The group aims to improve operations at energy storage facilities, update the fire code standards, and set a “gold standard” for a safe clean energy future. It is important to note that cell failure rates in battery storage are extremely low and safety features in today’s designs further reduce the probability of fires.

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[155] The sign of this value stream is negative because the Residential Energy Storage System Incentive Program does not add any direct CO_2 reduction benefits but rather shifts when carbon (or other fossil fuels) is being used. This value stream takes into account the environmental portion of the VDER value stack that is applied to the difference in energy during charge and discharge of the battery. As a result, this value is negative due to energy losses at discharge.
[156] Energy Storage News: New York governor’s working group on BESS safety recommends changes to state Fire Code

Consequently, PSEG Long Island has learned to address customer concerns to ensure community confidence in battery storage.

4.2.2.5. Next Steps

The program will remain in an ‘On Hold’ status until the additional $600,000 in NYSERDA funding is fully allocated and the LIPA-funded Block 3 incentive can begin. Once Block 3 launches, PSEG Long Island will conduct ongoing program administration such as reviewing applications, managing incentives through 2026, and distributing rebate payments on the allocated block through 2026 and 2027 (if necessary). Webpage updates for the program and a marketing video were completed in 2023 prior to the anticipated start of the program. Other ongoing marketing and outreach activities, such as press releases, emails, and SEO/SEM, will continue for the program until the end of Q3 2026.

4.3. Energy Storage Five-Year Plan

4.3.1. *Current State*

PSEG Long Island and LIPA intend to continue their contributions to the New York State CLCPA energy storage targets through incentives for existing and new energy storage projects on Long Island, and by contributing funding for statewide programs such as NYSERDA’s indexed storage credit procurements. As of March 2024, LIPA has approximately 31 MW of Behind-the-Meter (BTM) energy storage that has been interconnected and includes installed retail (~11.3 MW) and residential (~20.1 MW) applications. It is expected that 1.2 MW (238 systems) of additional energy storage will be added to the system on the residential side by the end of 2025. In 2018 and 2019, two Front-of-the-Meter (FTM) energy storage systems (ESS) in East Hampton and Montauk (5 MW each), respectively, were installed.

In 2021, LIPA issued a BESS request for proposal (RFP) for new storage projects to be added to PSEG Long Island’s service territory. 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 projects totaling 329 MW were selected for competitive contract negotiations. Subsequently, two projects dropped out leaving three energy storage projects totaling 179 MWs. The current expectation is that the 179 MW BESS RFP will be in-service by the end of 2028, but this is heavily dependent on the resolution of supply chain, import tax, and community storage moratorium complications, which are outside of the Utility’s control.

4.3.1.1. Residential and Retail Energy Storage

Residential behind-the-meter (BTM) energy storage systems (ESS; 20.1 MW as of March 2024) are the primary contributor to PSEG Long Island's 188 MW load-share target for the 2025 energy storage New York State CLCPA Goal. PSEG Long Island does not currently offer a retail energy storage incentive program to its customers, but approximately 11.3 MW (as of March 2024) from 14 energy storage systems with capacities ranging from >25 kW through 5,000 kW are currently registered on Long Island. Thus, as of March 2024, there is a total of approximately 31 MW of residential and retail BTM energy storage on Long Island.

PSEG Long Island conducted an analysis to compare the residential and retail energy storage adoption rates (%) to other New York Utilities.[157,158] The purpose of this analysis was to better understand and benchmark PSEG Long Island's current progress on implementing customer-sided energy storage. The resulting findings showed that compared to electric customers served by other New York Utilities, PSEG Long Island currently has the highest residential energy storage adoption rate (**Figure 4-3**).[159] Additionally, the number of residential ESS within PSEG Long Island's service territory greatly exceeds the number of ESS for other New York Utilities (**Table 4-11**). However, PSEG Long Island's retail energy storage adoption rate lags behind other New York Utilities because the Utility does not currently offer an incentive program for retail energy storage (**Figure 4-4**).[160]

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[157] The energy storage adoption rates (%) are calculated by dividing the number of residential or retail ESS for a New York Utility by the approximate total number of electric customers served by that New York Utility.
[158] Analysis is based on publicly available information in the NYS Standardized Interconnection Requirements (SIR) Inventory (as of March 2024).
[159] The resulting small-scale adoption rates (%) are due to the large number of electric customers that each New York Utility serves in comparison to the small number of registered residential and retail ESS.
[160] The New York IOUs incentivize retail storage projects using state funding authorized by the PSC for entities that contribute to the System Benefits Charge. LIPA is not eligible for such state funding and would have to use RGGI or internally generated funds to incentivize retail storage.

Figure 4-3. Residential Energy Storage Adoption Rate (%) by New York Utility (as of March 2024)[2]

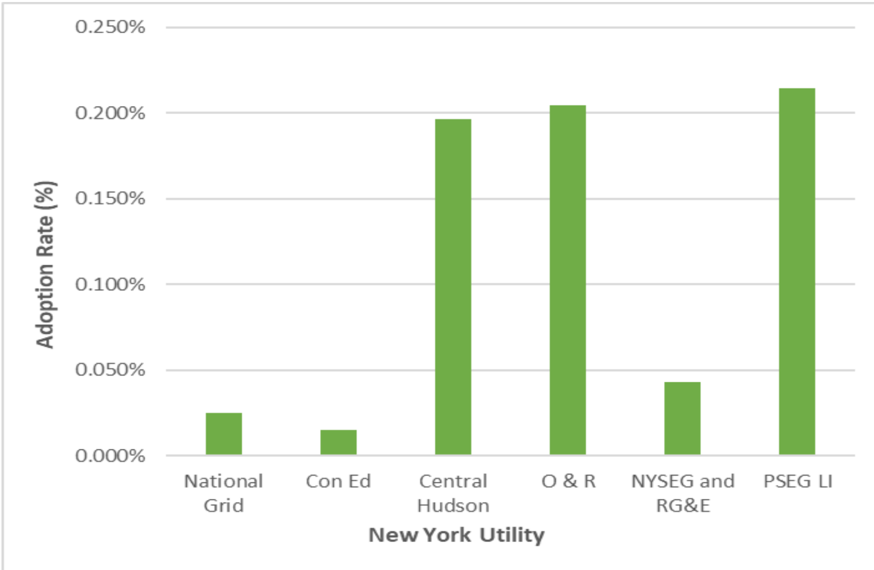
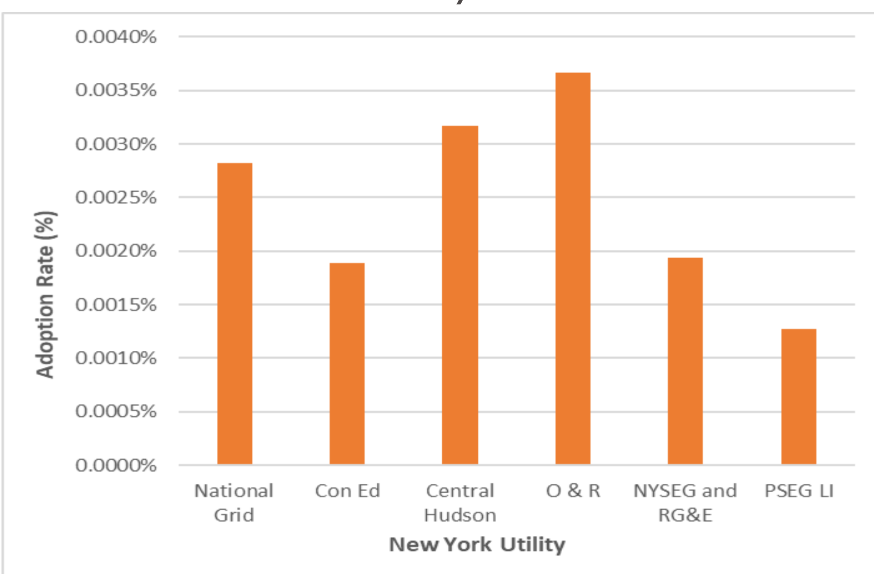


Figure 4-4. Retail Energy Storage Adoption Rate (%) by New York Utility (as of March 2024)[161]



[161] Analysis is based on publicly available information in the NYS Standardized Interconnection Requirements (SIR) Inventory (as of March 2024).

Table 4-11. Residential and Retail Energy Storage by New York Utility

Utility	Residential Energy Storage (< 25 kW)		Retail Energy Storage (>25 kW – 5,000 kW)		Total Energy Storage		Electric Customers Served[162]
	Systems	kWAC	Systems	kWAC	Systems	kWAC	Customers
National Grid	420	4,017	48	101,241	468	105,258	1,700,000
Con Ed	548	4,464	68	42,300	616	46,764	3,600,000
Central Hudson	619	5,208	10	6,572	629	11,780	315,000
O & R	613	5,194	11	30,910	624	36,104	300,000
NYSEG and RG&E	552	5,057	25	29,546	577	34,603	1,288,518
PSEG Long Island	2,356	20,134	14	11,282	2,370	31,416	1,100,000

Long Island was the first region of New York state to offer residential battery storage incentives. Between 2019 and 2021, the Utility 2.0 BTM Energy Storage plus Solar PV Program propelled residential battery storage installations on Long Island (estimated 2,356 residential ESS as of March 2024). The Utility 2.0 BTM Energy Storage Plus Solar PV Program became 'Operational' in 2022 and has since been superseded by the Utility 2.0 Residential Energy Storage System Incentive Program, which requires residential customers to enroll in the DLM Tariff, unlike the predecessor program.

The Utility 2.0 Residential Energy Storage System Incentive Program is anticipated to begin in April 2025 and is expected to achieve an additional 2.8 MW of energy storage from an estimated 555 systems over the course of two years (2025 – 2026). More information on this program can be found in **Section 4.2.2** above. The transition to Time-of-Day (TOD) rates will provide another revenue stream to incentivize customers to install storage in order to reduce their electric bill. TOD rate enrollments coupled with the required DLM Tariff enrollment for customers should further propel the residential energy storage market on Long Island and enable PSEG Long Island to better manage electricity usage during peak periods.

4.3.1.2. Utility Battery Storage

Two Front-of-the-Meter (FTM) storage systems were installed in 2018 and 2019 in East Hampton and Montauk, respectively. These storage applications have contributed an additional 10 MW (5 MW at each location) of 8-hour utility battery storage. LIPA is currently in negotiations for a further 179 MW of BESS that could potentially be in service by 2028 if the negotiations are successful and supply chain, import tax, and community storage

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[162] Approximation based on latest available data

moratorium complications are avoided. The utility-scale battery storage efforts described above are external to the Utility 2.0 Program, but these efforts greatly contribute to PSEG Long Island's portion of the 2025 and 2030 statewide energy storage CLCPA goals. Information on PSEG Long Island and LIPA's Integrated Resource Planning[163] and Long-Term Transmission Planning efforts can be found outside of the Utility 2.0 and EE Plans presented herein.

4.3.2. Gaps Analysis

At a statewide level, New York's energy storage procurement will need to bridge the gap between today's commitments of approximately 1.3 GW and the CLCPA goal of 6 GW of energy storage by 2030. Thus, at least 4.7 GW of new energy storage projects must be procured in time for deployment by the end of 2030. **Table 4-12** from NYSERDA's New York 6 GW Energy Storage Roadmap shows the statewide energy storage gap that must be achieved by the end of 2030.

Table 4-12. New York New Procurement Schedule (from NYSERDA's Energy Storage Roadmap)[164]

Storage Type	2023	2024	2025	2026	2027	2028	2029	2030
Bulk (3,000 MW)	-	1,000	1,000	1,000	-	-	-	-
Retail (1,500 MW)	-	375	375	375	375	-	-	-
Residential (200 MW)	13	27	27	27	27	27	27	27
Annual Total	13	1,402	1,402	1,402	402	27	27	27
Cumulative Total	13	1,415	2,817	4,218	4,620	4,647	4,673	4,700

At the utility level, by the end of 2030 PSEG Long Island will need to bridge the gap between the current firm commitment of 44.2 MW and PSEG Long Island's share of the 2030 energy storage CLCPA Goal.[165] To bridge the gap, LIPA can either build or procure its own bulk energy storage projects on Long Island, or contract with NYSERDA to purchase a share of the bulk Index Storage Credits (ISCs) that NYSERDA plans to procure as the primary mechanism for incentivizing utility-scale storage statewide. Similar to the other state utilities, LIPA will have the option to purchase on a voluntary basis up to its pro rata load share of the

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

[164] New York's 6 GW Energy Storage Roadmap: Policy Options for Continued Growth in Energy Storage

[165] PSEG Long Island achieving the load-share-ratio of 750 MW of Energy Storage on Long Island by the end of 2030 is dependent on the level of energy storage procured by the state and what share is contracted to PSEG Long Island. Thus, PSEG Long Island is committed to contributing to the overall 2030 statewide energy storage CLCPA goal, but the achievement of this goal is reliant on the progress of the state.

NYSERDA storage credits. **Table 4-13** details the current and potential future state (shown in orange) of energy storage procurement for PSEG Long Island.

Table 4-13. Current and Future State of Energy Storage Procurement for PSEG Long Island

	Storage Type	≤2022	2023	2024	2025	2026	2027	2028	2029	2030
Current State	Bulk	10.0	-	-	-	-	-	179.0	-	-
	Retail	10.6	0.2	0.5	-	-	-	-	-	-
	Residential	15.1	4.0	1.0	1.2	1.6	-	-	-	-
	Annual Total	35.7	4.2	1.50	1.2	-	-	179.0	-	-
	Cumulative Total	35.7	39.9	41.4	**42.6**	44.2	44.2	223.2	223.2	**223.2**
Future State	Bulk	10.0	-	-	-	-	-	179.0	*TBD*	338.8
	Retail	10.6	0.2	0.5	*TBD*	*TBD*	188.0	*TBD*	*TBD*	*TBD*
	Residential	15.1	4.0	1.0	1.2	1.6	*TBD*	*TBD*	*TBD*	*TBD*
	Annual Total	35.7	4.2	1.50	1.2	1.6	188.0	179.0	*TBD*	338.8
	Cumulative Total	35.7	39.9	41.4	**42.6**	44.2	232.2	411.2	*TBD*	**750**

Orange Text: Potential future state of energy procurement for PSEG Long Island.

High implementation costs for large-scale battery storage systems, as evident with the cancellation of the Utility 2.0 Miller Place Utility-Scale Storage Project in 2023, slow customer uptake, and the energy storage moratorium extension through April 2025, have and will likely continue to pose challenges for developing large storage projects on Long Island. In March 2024, the Southold Town Board voted to extend the BESS moratorium for utility-scale battery storage from April 2024 to April 2025.[166] The issuance of this moratorium was a result of three fires that occurred within a two-month span at BESS facilities in East Hampton, Warwick, and Chaumont in New York. Currently, PSEG Long Island does not anticipate significant impacts from this moratorium given that this ordinance does not affect residential- or retail-scale storage projects and that PSEG Long Island's 179 MW BESS in-service date has already been pushed back to 2028. However, if the moratorium is further extended into 2026 and beyond or expanded to include retail energy storage, it could pose a significant challenge for PSEG Long Island to contribute to the statewide 2030 energy storage CLCPA goal, especially since large-scale storage is the biggest contributing factor to CLCPA goal achievement.

[166] Z-1 Staff Report Town of Islip Moratorium BESS and The Suffolk County Times: Southold extends BESS Moratorium

In order to determine the most cost-effective solutions for the Energy Storage Five-Year Plan, PSEG Long Island developed a portfolio of energy storage benefit cost analyses (BCAs). This Energy Storage BCA Portfolio consists of a reforecasted Utility 2.0 Residential Energy Storage System Incentive Program BCA that was originally developed in 2022, a Retail Energy Storage BCA based on NYSERDA's New York statewide Retail Energy Storage Program[167], and a Non-Wires Alternative (NWA) Retail Energy Storage BCA.

The results from these analyses were mixed. Adding an additional value stream and the 8% increase in the Investment Tax Credit from 2022 to 2023 improved the BCA results in the reforecasted Residential Energy Storage System Incentive Program BCA compared to the original BCA. The Retail Energy Storage BCA results showed that significant incentive funding (~$84.6 M) would be required, which is beyond the capacity of the Utility at this time. The NWA Retail Energy Storage BCA results were favorable, however, much of the analysis is based on locational data from the canceled Miller Place project. So, the results from this BCA are specific to a location that is already pursuing alternative T&D upgrades. Thus, alternative funding source options, enhanced marketing, required rate enrollments, and ISC purchases should be considered in the near future to help fill the gaps in achieving PSEG Long Island's portion of the 2030 energy storage CLCPA goal.

4.3.2.1. Residential Energy Storage Reforecasted BCA

As mentioned above, the original BCA for the Residential Energy Storage System Incentive Program was reforecasted to account for timeline changes, $1.5 million in approved incentives rather than $2 million as originally proposed or the $1.8 million as approved, and the change in projected system enrollments as a result of the anticipated pushed back start date of the program to Q2 2025.

The reforecasted Residential Energy Storage System Incentive Program BCA has a societal cost test (SCT) benefit-to-cost ratio (BCR) of 0.67. For comparison, the SCT BCR in the original BCA was 0.39. This increase in the SCT BCR can be attributed to the addition of the Net Avoided CO_2 value stream incorporated into the reforecasted BCA and the 8% increase in the federal Investment Tax Credit[168] from 2022 to 2023 (22% to 30%). While even the reforecasted BCA appears economically unfavorable, the SCT BCR ratio does not illustrate the program's full benefits.

BTM technology has the potential to offer additional benefits that are not easily quantifiable for inclusion in a BCA. Increased property values, reduced risk of emergencies related to

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[167] New York's 6 GW Energy Storage Roadmap: Policy Options for Continued Growth in Energy Storage
[168] Inflation Reduction Act Tax Credit Opportunities for Energy Storage

power outages, job creation, decreased land used for power plants, and reduced emissions related to reduced usage of fossil fuel peaker plants on Long Island are examples of non-energy benefits not included in the BCA. Based on these non-energy benefits and other non-monetized benefits this program could offer (as described further in DPS's review and recommendations on the 2022 Utility 2.0 Plan)[169], LIPA ultimately approved of this program in 2022. As stated above, this program is anticipated to launch in April 2025, at which time realized benefits will start to be tracked and collected.

More information about the inputs and outputs of the reforecasted Residential Energy Storage System Incentive Program BCA can be found in **Section 4.2.2.3** above as a part of the 2024 Utility 2.0 Plan update for this program.

4.3.2.2. Retail Energy Storage Incentive Program BCA

Because PSEG Long Island does not currently offer an incentive program for retail energy storage systems, the installation rate for retail storage systems on Long Island has historically been low (See **Figure 4-4**. above). PSEG Long Island has the only non-subsidized sustainable Commercial Market for battery storage and has experienced moderate success with retail sized systems (14 systems) despite the absence of a retail incentive program. In comparison, the New York Retail Energy Storage Program funded by NYSERDA has seen success over recent years with approximately 320 MW of storage procured to date throughout New York.[170] As a result, NYSERDA plans to add funding for additional procurement of retail storage in order to support New York state in its achievement of the remaining retail component of the 2030 Energy Storage CLCPA Goal (1,500 MW).

In NYSERDA's New York 6 GW Energy Storage Roadmap, it is estimated that in order to procure an additional 1,500 MW of retail energy storage throughout New York the program costs (excluding administrative costs) would amount to approximately $675 million. To determine if a similar program is economically valuable and feasible for Long Island, PSEG Long Island conducted a BCA for a potential five-year Retail Energy Storage Program.

In this BCA, a potential Retail Energy Storage Incentive Program was structured similarly to NYSERDA's Retail Storage Program. The BCA examined standalone (non-Solar PV paired) behind-the-meter small retail energy storage systems (100 kW; 300 kWh) and large retail energy storage systems (1,000 kW; 3,000 kWh) that receive Value of Distributed Energy

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[169] State of New York Department of Public Service: Matter 14-01299
[170] New York's 6 GW Energy Storage Roadmap: Policy Options for Continued Growth in Energy Storage

Resources (VDER)[171] value for exports and do not participate in the New York Independent System Operator (NYISO) wholesale markets. Given PSEG Long Island's 12.5% load-share-ratio, PSEG Long Island examined supporting the installation of 188 MW of retail energy storage systems as a portion of the remaining 1,500 MW in retail energy storage needed to achieve this component of the 2030 Energy Storage Goal (1,500 MW x 12.5%).

The NYSERDA-funded Retail Energy Storage Incentive Program incentives average between $125/kWh and $150/kWh over the life of the program, with projects having an average duration of three hours.[172] PSEG Long Island modeled the average incentive rate in the BCA based on the higher-average incentive provided from the NYSERDA-funded program. As a result, the total up-front incentives available for the potential PSEG Long Island Retail Energy Storage Incentive Program was estimated to be approximately $84.6 million [(188 MW x 3 hour duration) x ($150/kWh x 1000 MWh/kWh) = $84.6 million].

The up-front incentives are placed on a declining Block structure based on a per kWh of usable installed storage capacity over the five-year assumed program length (2026 – 2030), with higher incentives for systems located in DACs. It is assumed that 30% and 70% of the allocated incentive funding would contribute towards the enrollment of small-scale retail ESS (100 kW) and large-scale retail ESS (1,000 kW), respectively. **Figure 4-5** below showcases the program inputs and outputs used in the BCA.

Benefit streams considered for this analysis include avoided energy (LBMP), avoided outage costs, avoided generation capacity cost (AGCC), avoided transmission capacity infrastructure, avoided distribution capacity infrastructure, and net non-energy benefits (Federal Investment Tax Credit (ITC)[173]). The benefits are largely driven by net non-energy benefits as a result of the high (30%) investment tax credit percentage that is available for standalone storage systems between 5 kWh and 1 MW between now and 2032. Benefits are also largely driven by avoided outage costs, which consider the avoided costs associated with acquiring a retail backup generator in the event of an outage. The BCA assumes that approximately 613 systems would enroll in the program and contribute to benefits.

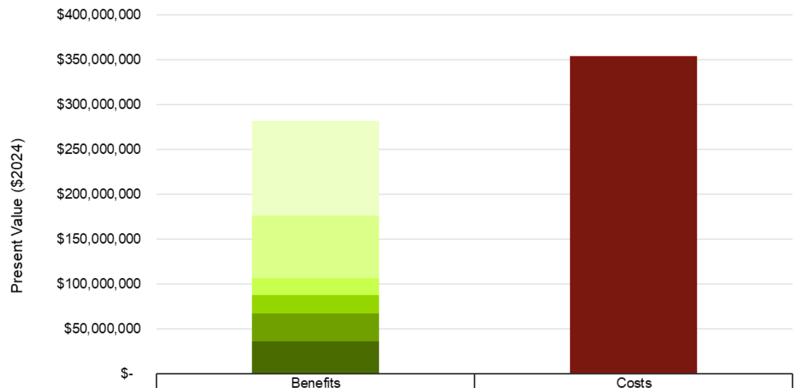
Program costs include program administration costs and participant DER costs. The participant DER cost represents the majority of the total program costs in the BCA. The

[171] The Value of Distributed Energy Resources (VDER)
[172] New York's 6 GW Energy Storage Roadmap: Policy Options for Continued Growth in Energy Storage. Incentives for the NYSERDA-funded Retail Energy Storage Program were chosen based on a difference between modeled revenue from the VDER calculator, as well as modeled revenue from individual project developers, and current cost projection for storage.
[173] Inflation Reduction Act Tax Credit Opportunities for Energy Storage

largest cost driver of the participant DER costs is attributed to the participant costs of the systems, as the hardware and installation costs of energy storage systems remain high.

PSEG Long Island does not believe that a Retail Energy Storage Incentive Program is economically feasible for implementation at this time. The potential Retail Energy Storage Incentive Program BCA resulted in a societal cost test (SCT) benefit-to-cost ratio (BCR) of 0.80 (UCT = 3.42, RIM = 1.22, PCT = 0.74). This decision was made given that the BCR is less than 1.0 and due to the extensive incentive funding ($84.6 M) that would be needed for this program. The net present value (NPV) of the resulting cost and benefit streams from the SCT in the BCA are shown in **Table 4-14** below.

Figure 4-5. Retail Energy Storage Incentive Program Present Value Benefits and Costs of SCT



	Benefits	Costs
Net Non-Energy Benefits	$105,883,907	$-
Avoided Outage Costs	$69,490,556	$-
Net Avoided CO2	$(366,455)	$-
Avoided Energy (LBMP)	$18,949,521	$-
Avoided Generation Capacity Cost (AGCC)	$19,979,318	$-
Avoided Transmission Capacity Infrastructure	$31,660,563	$-
Avoided Distribution Capacity Infrastructure	$35,846,353	$-
Program Administration Costs	$-	$428,202
Participant DER Cost	$-	$352,946,356
Total	$281,443,763	$353,374,558

Table 4-14. Retail Energy Storage Incentive Program Value Streams

#	Value Stream	Calculation Methodology	Benefits (NPV, $M)	Costs (NPV, $M)
1	**Avoided Distribution Capacity Infrastructure**	Based upon marginal capacity costs and estimated peak demand reduction	35.8	
2	**Avoided Transmission Capacity Infrastructure**	Based upon marginal capacity costs and estimated peak demand reduction	31.7	
3	**Avoided Generation Capacity Cost (AGCC)**	Based upon marginal capacity costs and estimated peak demand reduction	20.0	

#	Value Stream	Calculation Methodology	Benefits (NPV, $M)	Costs (NPV, $M)
4	**Avoided Outage Costs**	Calculated by valuating the avoided cost of acquiring a retail-scale gas backup generator[174]	69.5	
5	**Net Non-Energy Benefits**	Includes Investment Tax Credit (ITC) applied to upfront storage system costs (30%)	105.9	
6	**Avoided Energy (LBMP)**	Based upon 100% enrollment in commercial TOU rates and cost of electricity during peak versus off-peak ours	18.9	
7	**Net Avoided CO_2**	Accounts for the avoided CO_2 emissions during on- and off-peak hours for enrolled systems, the Value of E for PSEG Long Island Service Territory, and annual energy % losses	-0.4[175]	
8	**Participant DER Cost**	Accounts for participant cost of energy storage system hardware and installation cost		352.9
9	**Program Administration Costs**	Includes costs for customer outreach and general program administration		0.4
	Total Benefits		**281.4**	
	Total Costs			**353.4**
	SCT Ratio		**0.80**	

NPV = Net present value

4.3.2.3. Non-Wires Alternative Retail Storage BCA

PSEG Long Island examined a hypothetical use case for a 2.5 MW, 12.5 MWh non-wires alternative (NWA) battery storage solution that could provide enhanced T&D system benefits compared to a typical third party-owned project that enrolls in a utility Retail Energy Storage Incentive Program. This use case is very similar to the Utility 2.0 Miller Place Grid Storage Project that was canceled in 2023, but the funding cost assumptions have been updated based on industry standards and the funding mechanism has been updated to account for the VDER value stack as the primary incentive basis. Performance incentive shares for DAC customers have also been considered in this analysis.

Due to significant procurement delays, supply chain constraints, and changing market conditions, LIPA and PSEG Long Island jointly determined to pursue a traditional T&D

[174] The average price for a commercially available backup gas generator on a per kW basis can range from $300/kW to $400/kW. The upper bound of this range ($400/kW) was used in the analysis to account for other non-energy benefits and is escalated using inflation and reflects a one-time up-front price.
[175] The sign of this value stream is negative because this program does not add any direct CO_2 reduction benefits but rather shifts when carbon (or other fossil fuels) is being used. This value stream takes into account the environmental portion of the VDER value stack that is applied to the difference in energy during charge and discharge of the battery. As a result, this value is negative due to energy losses at discharge.

solution rather than a utility-scale battery storage system at the Miller Place substation, which lead to the project's cancellation in 2023. It is important to note that this NWA Retail Energy Storage BCA uses the same locational assumptions (i.e., Miller Place substation). PSEG Long Island determined that a new NWA for a different location was beyond the scope of this analysis as this analysis is intended to show the hypothetical benefits and costs of a standalone retail-sized energy storage system sited on utility-owned property (i.e., substation). In the future if LIPA were to consider owning retail energy storage or expanding upon LIPA-owned bulk energy storage, this BCA could be updated to include a new NWA and other locational factors.

Benefit streams considered for this analysis include avoided energy through Wholesale Energy Arbitrage (LBMP), avoided generation capacity cost (AGCC), avoided transmission capacity infrastructure, avoided distribution capacity infrastructure, and net non-energy benefits (VDER Value Stack, Community Credits, and DAC incentive shares)[176]. The benefits are largely driven by avoided distribution and generation capacity infrastructure given the NWA solution for this battery system.

Program costs include program administration costs, additional O&M for the storage system, and incremental T&D and DSP costs. The incremental T&D and DSP costs reflect the majority of the total costs in the BCA. These costs are largely driven by the industry-based, net present value of battery storage costs and the distribution deferral value for the Miller Place substation. As mentioned above, these costs are hypothetical, and the Miller Place locational dependency of the results must be taken into account.

Based on the above, this NWA Retail Energy Storage BCA has a societal cost test (SCT) benefit-to-cost ratio (BCR) of 1.11 (UCT = 0.80, RIM = 0.80). As described above, it is important to note that the benefits and costs are largely driven by the NWA use case for this BCA which are heavily dependent on location. Given that the Miller Place substation is pursuing a T&D solution, it is very unlikely that a battery storage system would be installed at this location. Thus, LIPA and PSEG Long Island should consider undergoing a NWA for a different favorable location and reforecasting the BCA in the future if the installation of retail energy storage on utility-owned property is considered for a Community Commercial Energy Storage Pilot Program. The net present value (NPV) of the resulting cost and benefit streams from the SCT in the BCA are shown in **Figure 4-6** and **Table 4-15** below.

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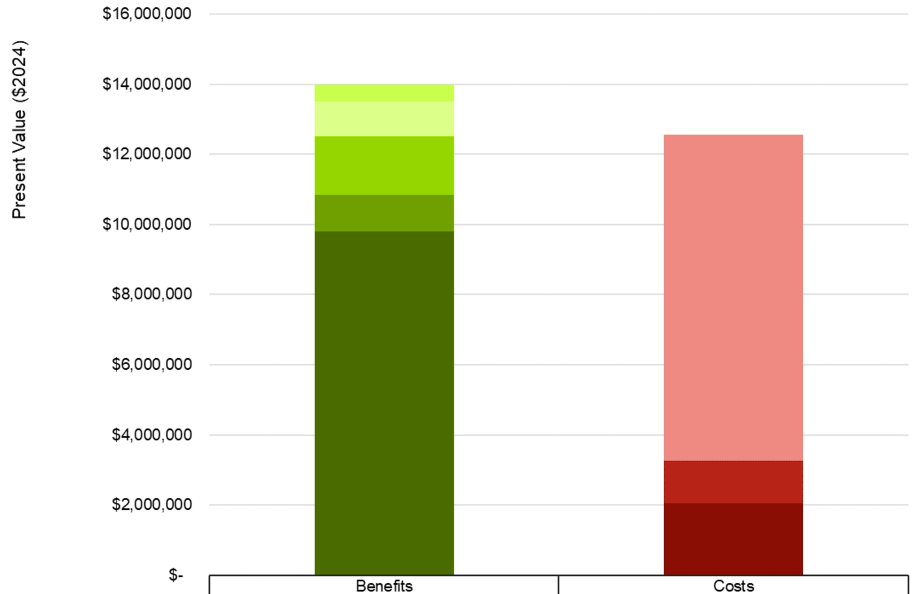
[176] The Value of Distributed Energy Resources (VDER)

Figure 4-6. NWA Retail Energy Storage Present Value Benefits and Costs of SCT



	Benefits	Costs
Net Non-Energy Benefits	$480,146	$-
Avoided Energy (LBMP)	$978,609	$-
Avoided Generation Capacity Cost (AGCC)	$1,691,768	$-
Avoided Transmission Capacity Infrastructure	$1,023,277	$-
Avoided Distribution Capacity Infrastructure	$9,810,944	$-
Incremental T&D and DSP Costs	$-	$9,282,172
Added O&M	$-	$1,226,153
Program Administration Costs	$-	$2,046,787
Total	$13,984,744	$12,555,111

Table 4-15. Retail-Commercial-Scale Energy Storage Value Streams

#	Value Stream	Calculation Methodology	Benefits (NPV, $M)	Costs (NPV, $M)
1	**Avoided Distribution Capacity Infrastructure**	Based upon marginal capacity costs and estimated peak demand reduction	9.8	
2	**Avoided Transmission Capacity Infrastructure**	Based upon marginal capacity costs and estimated peak demand reduction	1.0	
3	**Avoided Generation Capacity Cost (AGCC)**	Based upon marginal capacity costs and estimated peak demand reduction	1.7	
4	**Net Non-Energy Benefits**	Includes the VDER value stack and Community Credit incentive opportunities along with distribution of benefits to DAC customers	0.5	
5	**Avoided Energy (LBMP)**	Based upon wholesale energy arbitrage for the utility to purchase energy during off-peak hours	1.0	
6	**Incremental T&D and DSP Costs**	Includes battery storage capital costs (hardware and installation) and the distribution deferral value at Miller Place		9.3

#	Value Stream	Calculation Methodology	Benefits (NPV, $M)	Costs (NPV, $M)
7	**Added O&M**	Includes O&M required for battery maintenance, operations, and updates as well as any added O&M needed for community program needs		1.2
8	**Program Administration Costs**	Includes costs for general community program administration		2.0
	Total Benefits		**14.0**	
	Total Costs			**12.6**
	SCT Ratio		**1.11**	

NPV = Net present value

4.3.3. Future State

2030 Goal	TBD MW[177]
2030 Achievement (as of Q1 2024)	41 MW

Looking ahead, PSEG Long Island will continue to prioritize existing residential and utility-scale energy storage applications while also exploring other use cases for retail energy storage.

Beyond the 2025 and 2026 forecasted spend for the Utility 2.0 Connected Buildings Pilot (see **Section 4.2.1**) and Residential Energy Storage System Incentive Program (see **Section 4.2.2**), no additional Utility 2.0 Program funding for energy storage is planned for the next five years at this time. The primary reason for this outcome can be attributed to the high implementation and incentive costs for utility- and retail-scale battery storage systems, respectively.

In order to add any meaningful quantity of storage on Long Island, significant implementation of retail and/or bulk storage will be required. To supplement LIPA's own incentive programs and procurements, additional energy storage could be solicited from NYSERDA via index storage credits (ISCs), which can constitute as contribution from PSEG Long Island for its portion of the 2030 energy storage CLCPA goal. More information on the five year plans for each energy storage division can be found in the following subsections.

[177] This value is reflected as 'TBD' because PSEG Long Island achieving the load-share-ratio of 750 MW of Energy Storage on Long Island by the end of 2030 is dependent on the level of energy storage procured by the state and what share is contracted to PSEG Long Island. Thus, PSEG Long Island is committed to contributing to the overall 2030 statewide energy storage CLCPA goal, but the achievement of this goal is reliant on the progress of the state.

4.3.3.1. Residential Energy Storage

The Utility 2.0 Residential Energy Storage System Incentive Program is expected to launch in Q2 2025 and will continue through 2026. Due to the pushed backed start date of this program, the original 2022 benefit-cost analysis (BCA) was reforecasted in May 2024 to account for this timeline change, the approved incentive total ($1.5 million in incentives rather than $2 million as proposed in the 2022 Utility 2.0 Plan or $1.8 million as approved for 2023 - 2024), and the resulting impact on projected system enrollments. More information on the results of the reforecasted 2024 BCA can be found in **Section 4.2.2.3** above.

In order for a contractor to enroll an energy storage system into the Residential Energy Storage System Incentive Program, the system must be paired to solar PV. Over the past three years, the percent of residential solar PV paired with energy storage in PSEG Long Island's service territory has decreased (see **Table 4-16**). This decrease can be attributed to the rising costs of battery storage coupled with an increase in interest rates. Evidently, these factors have led to delays in Utility 2.0 projects reliant on the residential solar PV and energy storage markets (i.e., Connect Buildings Pilot and Residential Energy Storage System Incentive Program). PSEG Long Island will continue to support these local markets through various promotional marketing activities (e.g., Marketing Search Engine Optimizer (SEO), emails, bill inserts, promotional videos, etc.).[178]

Table 4-16. Percent of Solar PV paired with ESS by Year in PSEG Long Island Service Territory[179]

Year	Solar PV	Energy Storage Systems (ESS)	Percent (%)
2021	6,900	635	9.2%
2022	8,200	710	8.6%
2023	10,600	475	4.5%
Total	**25,700**	**1,820**	**7.0%**

At this time, there are no plans to expand the Residential Energy Storage System Incentive Program. However, depending on how the program progresses, PSEG Long Island may consider proposing a program expansion to include incentives for BTM electric vehicle energy storage applications. Currently, the program requires that participating ESS are

[178] Marketing efforts for the Connected Buildings Pilot are conducted by the third-party contractor SUNation as part of their existing interaction and relationships with the customers.
[179] Analysis is based on publicly available information in the NYS Standardized Interconnection Requirements (SIR) Inventory (as of March 2024).

paired with only solar PV, but this requirement could be updated in the future to include pairing electric vehicle charging with ESS, or standalone battery storage systems where the customer agrees to participate in PSEG Long Island's DLM tariffs. This potential program expansion could help mitigate the gap in customer adoption that exists with energy storage paired with solar PV. Modifications to the application and approval process for program participants and well as interconnection guidelines would also need to be taken into consideration.

4.3.3.2. Retail Energy Storage

As discussed above, PSEG Long Island does not plan to pursue a Retail Energy Storage Incentive Program, based on the "missing money" incentive model that NYSERDA has been using for the IOUs, given the significant amount of incentive funding ($84.6 M) that would be required. Even with the recent 8% increase in the federal ITC (22% in 2022 to 30% in 2023), the offset is not significant enough to make the implementation of a Retail Energy Storage Incentive Program economically feasible or socially beneficial. PSEG Long Island will continue to monitor market trends, examine alternative funding source opportunities, and investigate other possible use cases to determine whether a LIPA-funded program for retail-size storage is appropriate in the near future.

4.3.3.3. Alternative Concepts for a LIPA Retail Storage Incentive Pilot Program

In lieu of funding a retail energy storage program that offers an administratively determined fixed incentive amount, LIPA is considering a potential retail storage incentive pilot. This pilot would build on the Long Island VDER value stack and the current design for NYSERDA's statewide retail storage incentive program, with some potential additional elements or adjustments, such as:

- Competition for fixed incentive amounts or alternatively for indexed storage credits
- Pay-for-performance, rather than front-loaded incentives
- LIPA ownership in cases where LIPA's cost to own undercuts offers from third party storage developers, and where there are attractive opportunities for using retail storage as NWAs
- Use of LIPA-owned substations and other LIPA properties for siting retail storage projects
- Allocation of project benefits preferentially to DACs

4.3.3.4. Bulk and Utility-Scale Battery Storage

Other than the 2021 BESS RFP that is already in progress, no additional utility-scale battery storage is planned to be procured within the next five years. PSEG Long Island will continue to monitor market trends and determine in the near future if additional utility-scale applications are appropriate. PSEG Long Island and LIPA fully intend to evaluate

NYSERDA's BESS RFP to purchase index storage credits (ISCs) from NYSERDA or to purchase another RFP to further progress PSEG Long Island's 2030 energy storage CLCPA goal contributions.

In the New York 6 GW Energy Storage Roadmap, NYSERDA proposed a new, centralized procurement mechanism for bulk energy storage projects called index storage credits (ISCs). This ISC mechanism is similar in many respects to the "Index Renewable Energy Credits (RECs)" approach that was adopted by the Commission and utilized in NYSERDA's Tier 1 REC and Offshore Wind REC solicitations.[180] Under this structure, energy storage developers bid a "Strike Price" into a NYSERDA-administered competitive solicitation and the payments are determined by comparing the "Strike Price" to a "Reference Price" based on an index of expected wholesale market revenues. Funding for payments is provided through bill collections from NY Load-Serving Entities (such as PSEG Long Island).

Now that the DPS has approved the New York 6 GW Energy Storage Roadmap (current as of June 20, 2024), and subsequently the ISC Mechanism for energy storage, PSEG Long Island can support payments for ISCs for Grid-connected storage technologies.[181] One ISC would represent one MWh of energy storage capacity that is operational on a given day. This means that each day a storage project is operational, it would be credited with and compensated for a number of ISCs equal to the MWh of storage discharge capacity of the unit. As a result, PSEG Long Island would receive MWh Energy Storage Credits that can be counted towards PSEG Long Island's contribution to the statewide CLCPA Goal (similar to the Clean Energy Standard framework).

4.3.4. Energy Storage Five-Year Plan Summary

As discussed throughout the sections above, PSEG Long Island will continue to prioritize existing residential and utility-scale energy storage applications while also supporting LIPA with the implementation of the Retail Storage Pilot Program, if approved by LIPA executive management.

Outside of the 2025 and 2026 forecasted spend for the Utility 2.0 Residential Energy Storage System Incentive Program (see **Section 4.2.1**) and Connected Buildings Pilot (see **Section 4.2.2**), no additional Utility 2.0 Program funding for energy storage is planned for the next five years at this time. The primary reason for this outcome can be attributed to the high implementation and incentive costs for utility- and retail-scale battery storage systems, respectively. Furthermore, customer adoption of residential energy storage on Long Island

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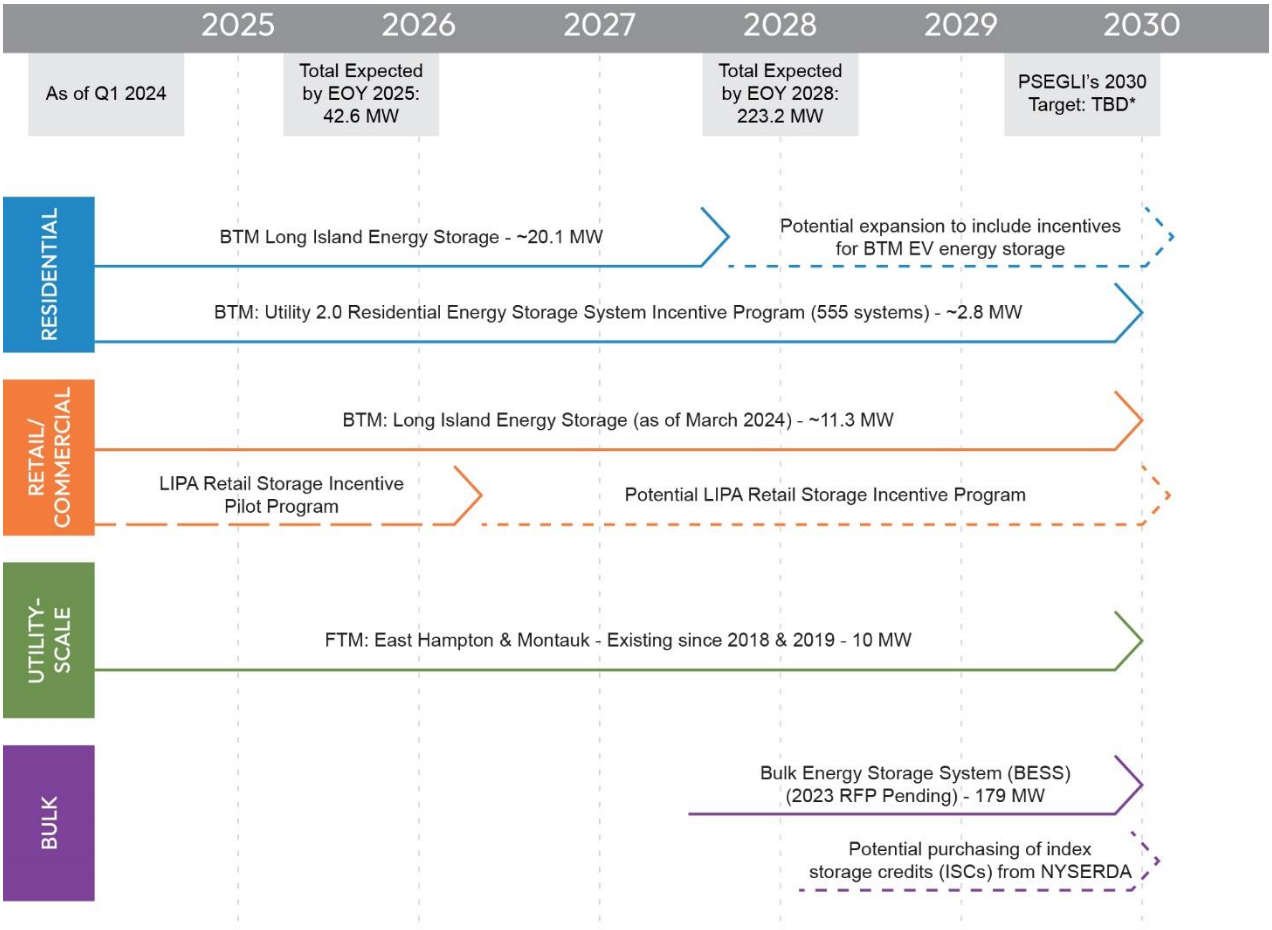
[180] NYSERDA's Tier 1 REC and Offshore Wind REC
[181] Approval of New York's Nation-Leading Six Gigawatt Energy Storage Roadmap Announced

peaked in 2022 (30% of all residential energy storage installations on Long Island to-date occurred in 2022) and has declined over recent years. This reduced customer adoption is likely the result of increases in interest rates and overall battery storage costs in recent years, changes on lending patterns resulting from bank failures in early 2023 and rises in fire safety concerns leading to an overall negative public perception of battery storage.

Ultimately, a robust level of large-scale energy storage will need to be procured by PSEG Long Island either through ISCs or an additional issuance of RFPs for the Utility to fully contribute to its portion of the 2030 energy storage CLCPA goal. As described above, the majority of large-scale energy storage procurement occurs outside of the Utility 2.0 Program and the overall scale and cost of a potential retail energy storage project is currently beyond the capacity of the Utility 2.0 Program. Thus, the Utility 2.0 Program will continue to drive the Residential Energy Storage System Incentive Program and support the broader LIPA and PSEG Long Island teams with retail and utility-scale energy storage procurement. **Figure 4-7** below details the energy storage plans for the next five years (2025 – 2030) by division (Residential, Retail, and Utility-Scale).

Figure 4-7. Energy Storage Five-Year Plan Summary (2025-2030)



**This value is reflected as 'TBD' because PSEG Long Island achieving the load-share ratio of 750 MW of Energy Storage on Long Island by the end of 2030 is dependent on the level of energy storage procured by the state and what share is contracted to PSEG Long Island. Thus, PSEG Long Island is committed to contributing to the overall 2030 statewide energy storage CLCPA goal, but the achievement of this goal is reliant on the progress of the state.*

4.3.4.1. Five-Year Plan Financial Impact

As a part of the five-year planning process, PSEG Long Island examined the potential Utility 2.0 financial impact on supporting energy storage implementation. As mentioned above, no new Utility 2.0 energy storage projects are proposed for next year and no additional Utility 2.0 Program funding for energy storage is planned for the next five years at this time.

Currently, the only costs planned for the Utility 2.0 Program related to energy storage are attributed to the already approved Residential Energy Storage System Incentive Program that is expected to launch in Q2 2025 and run through 2026 and the Connected Buildings Pilot. **Table 4-17** shows the combined forecasted budgets for both of these initiatives. If available energy storage technologies, interest rates, customer adoption, or other factors change market conditions considerably in the future, PSEG Long Island will reexamine if any new or expanded Utility 2.0 energy storage projects are deemed worth pursuing (reflected as 'TBD' in **Table 4-17** below for 2027 – 2030). At that time, PSEG Long Island will examine any potential business cases and associated costs for proposal(s) in that respective year's Utility 2.0 Plan.

Table 4-17. Five-Year Forecasted Budget (2025 to 2030)

	2025	2026	2027	2028	2029	2030	Total
	Request	*Forecast*	*Forecast*	*Forecast*	*Forecast*	*Forecast*	
Capital	-	-	*TBD*	*TBD*	*TBD*	*TBD*	-
O&M	$0.69M	$0.95M	*TBD*	*TBD*	*TBD*	*TBD*	$1.64M
Total	**$0.69M**	**$0.95M**	***TBD***	***TBD***	***TBD***	***TBD***	**$1.64M**

5. Solar PV

2024 Utility 2.0 Plan Annual Filing, Energy Efficiency Plan, and Five-Year Plan

5. Solar PV

New York State recognizes that the advancement of zero-emission energy resources is critical to delivering safe and reliable electricity to customers while reducing vulnerability to fossil fuel disruptions and energy price volatility[182]. The State's commitment to enabling zero-emission energy resources includes over $35 billion towards 120 large-scale renewable and transmission projects across New York and $1.8 billion allocated to scaling solar generation.[183]

PSEG Long Island customers are increasingly seeking access to rooftop solar and solar energy as a generation resource. In the past, the Utility 2.0 portfolio has proposed, funded, and operationalized a number of initiatives that enable the growth of solar and other DERs on the LIPA distribution system. These projects include the DER Visibility Platform, Increasing Hosting Capacity Study, Hosting Capacity Maps, and Behind-the-meter (BTM) Storage and Solar programs. This year's Utility 2.0 Plan filing requests funding for the continuation of the Residential Energy Storage System Incentive Program (**Section 4.2.2**) which also supports access to residential storage, making storage systems that complement solar generation more accessible.

5.1. 2025 Goal Achievement

New York State's 2025 statewide goal for distributed solar generation is 6,000 MW[184]. PSEG Long Island's share of the statewide Solar PV 2025 Goal is 750 MW, which was determined based on PSEG Long Island's load share ratio. As of 2023**,** PSEG Long Island has exceeded its share of the 2025 goal for solar generation, achieving 1,059 MW (**Figure 5-1**).

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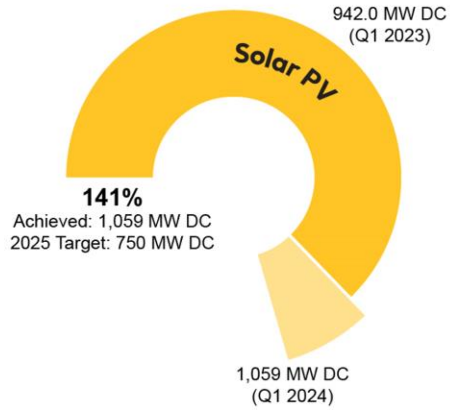
[182] New York State Climate Action Council. Scoping Plan – Full Report December 2022.
[183] New York State Climate Action Council. Scoping Plan – Full Report December 2022.
[184] New York State Climate Action Council. Scoping Plan – Full Report December 2022.

Figure 5-1. Solar PV 2025 Goal Achievement



Solar PV is procured in Long Island outside of the Utility 2.0 portfolio. Solar PV procurement is achieved in one of three ways[185]:

1. LIPA's **electric rate tariff** provides for payments to customer owned solar and storage
2. LIPA may issue RFPs to construct utility-scale resources
3. LIPA can contract with NYSERDA to **purchase a share of the RECs** from wind and solar projects

The BTM Solar program accounts for over 500 MW of BTM solar generation. The New York Sun funding was extended in 2020[186] and 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, PSEG Long Island has completed and installed a total of over 80,000 solar projects, reflecting about 8% of the customer base.

There is 200.2 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. The second is the 36 MW Riverhead Solar 2 project. Discussions are current ongoing for this NYISO queue project.

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[185] Long Island Power Authority (LIPA). *2023 IRP Summary Guide.*

[186] New York State Department of Public Service. Matter 19-02670. Order Extending and Expanding Distributed Solar Incentives.

To further support commercial solar development on Long Island, PSEG Long Island implemented four Solar Feed-in-Tariff (FIT) programs which have 85.1 MW in operation and 14.7 MW in award. These programs consist of:

1. FIT I since 2012, with 38.8 MW in operation
2. FIT II since 2013 with 32 MW in operation
3. FIT III since 2016 with 15.4 MW in operation and 2.7 MW pending and,
4. In May of 2020 LIPA and PSEG Long Island launched a new Feed-in-Tariff program, termed Solar Communities or FIT V, with three Power Purchase Agreements (PPAs) signed for 7 MW and one award made for 5 MW.

Solar Communities is a program designed to deliver affordable clean energy to income-eligible households, which have traditionally been underserved in the solar market.[187] The Solar Communities program plans to double the amount of community solar on Long Island. As of May 24, 2024, three PPAs have been executed, totaling 7 MW. The FIT V program is now closed and no longer accepting new applications.

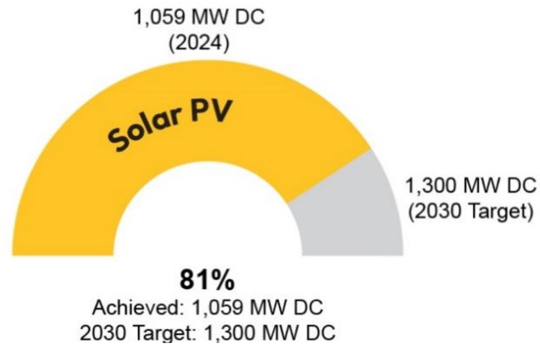
New York State regularly updates a map detailing statewide distributed solar projects, including those on Long Island. Refer to the most recent information on PSEG Long Island's current solar portfolio here.

5.2. Solar PV Five-Year Plan

New York State's statewide goal for solar generation in 2030 is 10,000 MW[188] with PSEG Long Island's share being 1,310 MW. To date, PSEG Long Island has achieved 81% of its Solar PV 2030 Goal (**Figure 5-2**).

[187] Solar Communities Feed-In Tariff V
[188] New York State Climate Action Council. Scoping Plan – Full Report December 2022.

Figure 5-2. Solar PV 2030 Goal Achievement



PSEG Long Island will continue to grow its existing portfolio to meet the statewide goal. The current Solar PV portfolio is estimated to grow to 1,414.8 MW by early 2030s [189] (**Table 5-1**).

Table 5-1. PSEG Long Island Solar PV Project Portfolio

Project/Initiative Name	Size (MW)	In-Service (Estimated or Actual)
Long Island Solar Farm	32	2011
Eastern Long Island Solar Project	11	2013
Shoreham Solar Commons	25	2018
Riverhead Solar	20	2019
Kings Park Solar 1 and 2	4	2019
Solar Feed-in Tariffs I-III	87.8	2025
LI Solar Calverton	23	2021
Solar Communities (FIT V)	12	2025
Behind-the-Meter	1,200	2030
Total	**1,414.8**	

Based on this projected growth, Long Island is expected to exceed its 2030 Solar PV Goal by 2030. PSEG Long Island will also continue to utilize the three methods of solar procurement discussed in **Section 5.1** above, to address any potential gaps to achieving its share of the statewide 2030 Solar PV Goal. While there are no programs planned within Utility 2.0 that directly contribute to increased solar generation, the Utility 2.0 portfolio will continue to indirectly support New York State's 2030 Solar PV Goal by planning for increased grid flexibility and increasing accommodation for two-way connectivity over the next five years.

[189] Long Island Power Authority (LIPA). *2023 IRP Summary Guide.*

6. Other Programs

2024 Utility 2.0 Plan Annual Filing, Energy Efficiency Plan, and Five-Year Plan

6. Other Programs

Utility 2.0 programs have historically spanned a wide variety of topic areas, evolving alongside utility and customer priorities to address the most pressing needs of the energy transition. Past Utility 2.0 initiatives have focused heavily on addressing customer needs and growing our relationship with customers. For example, the development and deployment of AMI technology and systems has been foundational to making advanced energy technologies available to customers.

PSEG Long Island completed 98.6% of the planned AMI deployment by December 2023 which enabled increased customer benefits and operational efficiencies. 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 to empower customers to take control of their energy usage more effectively and support efficient management of the electric grid. PSEG Long Island is committed to providing customers with greater access to data and information, enabling them to better manage their energy use

The Integrated Energy Data Resource (IEDR) platform is intended to provide the 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. Access to this data is intended to support increased penetration of DERs and contribute to several New York State priorities.[190]

Chapter Contents

[190] The Data Access Framework adopted in this [Public Service Commissioner] 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, Order Adopting a Data Access Framework and Establishing Further Process (issued and effective April 15, 2021), at 72.

6.1. Integrated Energy Data Resource (IEDR) Platform

2024 Status	Active
2025 Status	Active
Start Year	2024
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 as the IEDR sponsor responsible for defining, initiating, overseeing, and facilitating the IEDR program on behalf of New York State and for coordinating with other stakeholders that will also have a role in implementing the IEDR platform including the DPS and the New York State investor-owned electric and gas utilities (IOUs).

NYSERDA is leading the effort to develop an IEDR platform to satisfy the New York State PSC order 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 also 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.

In May 2022, the JU filed a petition[191] 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[192], 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-

[191] Cases 20-M-0082 and 18-M-0376 Joint Utility Petition to Modify Self Attestation, filed on May 4, 2022.
[192] Cases 18-M-0376,Order Establishing Minimum Cyber Security and Privacy Protections and Making Other Findings (issued and effective October 17, 2019).

Attestation review and recommend further updates. As of April 2024, the petition remains pending disposition from the PSC.

In addition, in December 2022, the JU filed a second petition[193] seeking direction from the Commission regarding the direct sharing of protected customer data with the NYSERDA IEDR platform provider, ESource. It was the JU's position that there is no explicit requirement in the IEDR Implementation Order[194] or the April 2021 Data Access Framework[195] for utilities to share data without customer consent. This petition requested the following:

- That the Commission explicitly direct the Joint Utilities 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.
- That the Commission clarify that the IEDR Platform Provider does not share Protected Data with third parties until customer consent is obtained.
- Authorization to add utility-specific tariff language that releases the utility from liability associated with data loss or cyber incidents associated with the IEDR platform. 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[196].

In October 2023, the PSC responded to the JU petition, with the following:

- JU was directed to begin the transfer or non-anonymized customer data to the IEDR platform within 30 days,
- The PSC confirmed that any data being accessed by a third party via the IEDR platform would only be released consistent with the PSC's existing Data Access Framework (DAF) policies and requirements such that in a circumstance where a third party must obtain customer consent to gain access to certain data pursuant to the DAF, such third party would be continued to obtain customer consent once that data is warehoused with the IEDR;

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

[194] Case 20-M-0082, Order Implementing an Integrated Energy Data Resource (issued and effective February 11, 2021) ("IEDR Implementation Order").

[195] 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).

[196] Case 20-M-0082, Petition Seeking Commission Direction Regarding the Direct Sharing of Protected Customer Data, filed December 1, 2022.

- Directed the JU to file tariff language that eliminates utility liability for an improper access or sharing of customer data sets by the IEDR Administrator.

While the JU was ordered to start sharing customer data within 30 days of the PSC order, that did not include PSEG Long Island or LIPA as LIPA is not a PSC jurisdictional utility.[197]

6.1.1. Implementation Update

As per the Utility 2.0 approved budget for 2023, PSEG Long Island initiated the start of the IEDR project. The Project Initiation phase included building a PIP (Project Implementation Plan) for LIPA's approval. In addition, the team began engaging with NYSERDA and Esource to gather requirements including any legal and cybersecurity matters that should be taken into consideration. Based on the use cases identified by NYSERDA, the team worked on identifying the data sources for each data field requested. This required meeting with each internal data owner to help identify data fields as well as the security classification for data related to Customer, Network, Rates and Tariff.

In parallel, several discussions were held with NYSERDA's vendor Esource to understand the IEDR platform architecture and security details. PSEG Long Island initiated its internal process for vendor security approval which required Esource to complete a security questionnaire as well as provide very detailed security reports required by internal cybersecurity for approval. These detailed tasks were completed in 2023 and resulted in the identification of certain IEDR platform security concerns communicated to LIPA.

In December 2023, the PSEG Long Island team re-engaged LIPA to align on the strategy and approach for the IEDR project, including discussions of data security. The team identified several security and logistical concerns associated with the data requested and the security of the IEDR platform. The privacy concerns are summarized below.

- Privacy Concerns - Sending customer data to a third party without customer consent could potentially violate certain customer privacy rights and PSEG Long Island privacy policies. Examples include Customer contact information (Name, Address, Phone Number, Email Address etc.), Billing Data, Energy Usage Data etc.
- Security Concerns - Comprehensive customer data will be stored on a third-party platform posing a high business risk. The IEDR platform is not auditable by our cybersecurity team and therefore, we would have no control over our data or know about potential security risks. In addition, having sensitive data collected from all New York State utilities on one platform can lead to a high value target for bad actors.

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[197] Case 20-M-0082, Order Addressing Integrated Energy Data Resource Matters (issued and effective October 13, 2023).

- Sharing CEII Data - Sharing data that PSEG Long Island and/or LIPA may consider Critical Energy Infrastructure Information (CEII) presents physical security risks too. Examples of data requested include Feeder locations, Substation location data (GIS).
- Liability Coverage - The PSC order facilitated tariff language changes for the JUs designed to protect them from liability in the event improper access or sharing of customer data after the utility transfers such data to the IEDR platform. As of the date of publishing this Utility 2.0 Plan, the LIPA Tariff does not contain similar language.

6.1.1.1. Scope Update

Once the path forward is confirmed, the scope of work for 2024 will include proceeding with the implementation of the selected solution. We will continue to evaluate the business and technical requirements for the solution that may be developed to aggregate and transfer the data to the IEDR. For each of the data types (Customer, Network, Rates, and Tariff) data, our team will design and build data pipelines to securely feed the data to the IEDR platform. In addition, the team will need to design a customer authorization solution that allows customers to consent to sharing data with ESEs that request it.

6.1.1.2. Schedule Update

The legal and cybersecurity reviews led to additional discussions with LIPA which were previously not included in the schedule. The project schedule has been extended out. This year, PSEG Long Island will design a solution for aggregating and sharing the required data for the MVP use cases with the IEDR platform. The testing and deployment of the solution and pipelines will run into 2025.

6.1.1.3. Risks and Mitigations

Table 6-1. Risk and Mitigation Assessment – IEDR Platform

Category	Risk	Mitigation
Privacy	Sending customer data to a third-party platform without customer consent could violate certain customer protections.	Working with PSEG and LIPA Legal teams to identify whether sharing this data is a violation of any customer protections.
Security	Comprehensive customer data stored on a third-party platform presents a business risk.	Working with our cybersecurity team to ensure that appropriate protections are in place on the platform.

Category	Risk	Mitigation
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.
CEII Data	Some of the data requested by NYSERDA for the IEDR is considered CEII data and sharing it external presents security risks.	PSEG Long Island will not share CEII data with the platform.
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.

6.1.2. Funding Reconciliation and Request

The previously submitted budget estimates were based on the best-known schedule of activities provided by NYSERDA at the time of submittal. However, the delays in resolving the cybersecurity and legal concerns with LIPA have impacted the implementation timeline.

The original 2024 capital budget for IEDR project of $4.075 M has been reforecast to reflect the updated project timelines. Therefore, the new 2024 forecast will be $2.02 M for this year, with a shift of $1.17 M to 2025 and $2.00 M to 2026, in alignment with expected implementation. In addition, the $0.5 M in O&M originally planned for 2024 and 2025 has also been adjusted to $0.2 M in 2025 and $0.4 M in 2026, to better align with expected delivery of an internal solution.

Updated annual budget and variances are shown in **Table 6-2** and **Table 6-3**. It is important to note that budgetary values presented in the tables below are rounded to the hundredths decimal place.

Table 6-2. Capital and Operating Expense Budget, Actual and Forecast ($M)[198]

	Actual ($M) 2023	Updated Forecast ($M) 2024	Request ($M) 2025	Projected (Not Requested) ($M) 2026	Total ($M)
Capital	0.19	1.92	3.40	1.60	7.11
O&M	-	0.10	0.29	0.40	0.79
Total	**0.19**	**2.02**	**3.69**	**2.00**	**7.90**

Table 6-3. Capital and Operating Expense Variance

	2023 ($M)	2024 ($M)	2025 ($M)
Capital	(0.59)	(2.16)	1.57
O&M	-	(0.40)	(0.40)
Total	**(0.59)**	**(2.56)**	**1.17**

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.

6.1.4. Next Steps

Upon LIPA's approval, PSEG Long Island will develop a solution for aggregating the required data sets and sharing with the IEDR platform and take other appropriate steps to align with the JUs.

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[198] A portion of the Capital Forecasts for 2024-2026 are attributed to Capital Expenditure for Utility 2.0 PMO Support on the IEDR Platform.

7. Utility 2.0 Portfolio-Level Summary Tables

2024 Utility 2.0 Plan Annual Filing, Energy Efficiency Plan, and Five-Year Plan

7. Utility 2.0 Portfolio-Level Summary Table

7.1. Funding Requested for New and Active Utility 2.0 Initiatives

Table 7-1 summarizes the updated funding request for active projects, broken out by Capital and O&M expenditures. Given that the 2024 Utility 2.0 Plan is representative of a one-year outlook, the funding requests regard only 2025. Estimated spending projections are provided for 2026, however, this outer year will be revisited in next year's 2025 Utility 2.0 Plan. It is important to note that budgetary values presented in the table below are rounded to the hundredths decimal place.

Table 7-1. 2025 Funding Request and 2026 Projections for Active and Proposed Initiatives[199]

Status	Initiative Name	Capital Expenditure ($M)			O&M Expenditure ($M)			2-Year Total Request
		Request 2025	Projected 2026	2-Year Total	Request 2025	Projected 2026	2-Year Total	
Active	**Make-Ready Programs[200]**	7.83	8.77	16.60	10.34	17.48	27.82	44.42
	EV Make-Ready Program	*6.27*	*6.29*	*12.57*	*9.28*	*16.13*	*25.41*	*37.98*
	Fleet Make-Ready Program	*1.56*	*2.48*	*4.04*	*1.06*	*1.35*	*2.41*	*6.45*
	Electric Vehicle Programs[200,201 200]	2.01	0.11	2.12	2.82	1.78	4.59	6.71
	Demand Charge Rebate	-	-	-	*1.00*	-	*1.00*	*1.00*
	EV Phase-In Rate	*2.01*	*0.11*	*2.12*	*0.19*	*0.20*	*0.39*	*2.51*
	Residential Charger Rebate Program	-	-	-	*1.38*	*1.38*	*2.76*	*2.76*
	Suffolk County Bus Make-Ready	-	-	-	0.31	-	0.31	0.31
	Connected Buildings Pilot	-	-	-	0.04	-	0.04	0.04
	Residential Energy Storage Program	-	-	-	0.65	0.95	1.60	1.60
	IEDR Platform[200200]	3.40	1.60	5.00	0.20	0.40	0.60	5.60
	Total Utility 2.0 Programs	**13.24**	**10.49**	**23.72**	**14.36**	**20.60**	**34.96**	**58.68**

[199] EE Program budget is not included in this table since the EE Program budget is funded separately from Utility 2.0 Programs.

[200] A portion of the Capital Forecasts for 2025 and 2026 are attributed to Capital Expenditure for Utility 2.0 Project Management Office (PMO) Support for the Make-Ready Programs, EV Programs, and the IEDR Platform.

[201] Marketing and Outreach for the Electric Vehicle Programs is all encompassing. So, the Marketing and Outreach is included in the Overall O&M Total for the Electric Vehicle Program, but it is not allocated to a specific sub-project within the Electric Vehicle Program. Thus, the Electric Vehicle Programs O&M Totals do not equal the sum of the sub-project O&M Totals.

7.2. Budget Variance for Ongoing Utility 2.0 Initiatives

PSEG Long Island reconciled 2023 actual spend with the approved budgets that were filed in the 2023 Utility 2.0 Plan for each of the Utility 2.0 initiatives. The Utility also re-forecasted the budget for all ongoing initiatives for the period between 2024 and 2026.

Table 7-2 shows the variance between the approved 2023 budgets, the actual 2023 spend, and the updated 2023 – 2026 projected budgets for the currently active Utility 2.0 initiatives. **Table 7-3** shows the variance by Utility 2.0 initiative broken out by year. Cost-level details for the 2023 actual spend, 2024 planned spend, 2025 requested spend, and 2026 projected spend are included in Chapters 3 through 6. Please note, as in other variance tables throughout this document, negative values reflect an actual or projected underspend of the previously filed budget. It is important to note that budgetary values presented in the tables below are rounded to the hundredths decimal place.

Table 7-2. 2023 – 2026 Variance Between Approved Budget and Updated Initiative Spending

Status	Initiative Name	Capital Expenditure ($M)			O&M Expenditure ($M)			Total Variance
		2023 Budget 2023 - 2026	Updated Forecast 2023 - 2026	Total Capital Variance	2023 Budget 2023 - 2026	Updated Forecast 2023 - 2026	Total O&M Variance	
Active	**Make-Ready Programs**	11.07	21.78	10.71	26.18	40.37	14.19	24.90
	EV Make-Ready Program	*8.79*	*16.94*	*8.15*	*23.51*	*36.48*	*12.97*	*21.12*
	Fleet Make-Ready Program	*2.28*	*4.84*	*2.57*	*2.62*	*3.88*	*1.22*	*3.78*
	Electric Vehicle Programs[202]	2.09	2.82	0.73	8.06	8.44	0.37	1.10
	Demand Charge Rebate	-	-	-	*5.10*	*3.33*	*(1.77)*	*(1.77)*
	EV Phase-In Rate	*2.09*	*2.82*	*0.73*	-	*0.39*	*0.39*	*1.12*
	Residential Charger Rebate Program	-	-	-	*2.69*	*4.13*	*1.44*	*1.44*
	Suffolk County Bus Make-Ready	0.01	0.05	0.05	0.69	0.76	0.07	0.12
	Connected Buildings Pilot	-	-	-	0.35	0.34	(0.01)	(0.01)
	Residential Energy Storage Program	-	-	-	2.00	1.63	(0.37)	(0.37)
	IEDR Platform	6.68	7.10	0.43	1.10	0.70	*(0.40)*	0.03
	Total Utility 2.0 Programs	**19.84**	**31.76**	**11.92**	**38.38**	**52.24**	**13.86**	**25.78**

[202] Marketing and Outreach for the Electric Vehicle Programs is all encompassing. So, the Marketing and Outreach is included in the Overall O&M Total for the Electric Vehicle Program, but it is not allocated to a specific sub-project within the Electric Vehicle Program. Thus, the Electric Vehicle Programs O&M Totals do not equal the sum of the sub-project O&M Totals.

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

Status	Initiative Name	Total Variance from 2023 Filed Plan ($M) 2023	2024	2025	2026	Total
Active	**Make-Ready Programs**	(2.80)	(0.19)	1.65	26.25	24.90
	EV Make-Ready Program	*(2.73)*	*(0.17)*	*1.60*	*22.42*	*21.12*
	Fleet Make-Ready Program	*(0.07)*	*(0.02)*	*0.05*	*3.83*	*3.78*
	Electric Vehicle Programs[203]	(0.43)	(0.54)	0.19	1.89	1.14
	Demand Charge Rebate	*(0.43)*	-	*(1.35)*	-	*(1.77)*
	EV Phase-In Rate	-	*0.03*	*0.03*	*1.38*	*1.46*
	Residential Charger Rebate Program	-	*(0.57)*	*1.38*	*0.31*	*1.12*
	Suffolk County Bus Make-Ready	(0.66)	0.46	0.31	-	0.12
	Connected Buildings Pilot	(0.25)	0.20	0.04	-	(0.01)
	Residential Energy Storage Program	(0.27)	(1.54)	0.50	0.95	(0.37)
	IEDR Platform	(0.59)	(2.56)	1.17	2.00	0.03
	Total Utility 2.0 Programs	**(4.99)**	**(4.17)**	**3.85**	**31.09**	**25.78**

[203] Marketing and Outreach for the Electric Vehicle Programs is all encompassing. So, the Marketing and Outreach is included in the Overall O&M Total for the Electric Vehicle Program, but it is not allocated to a specific sub-project within the Electric Vehicle Program. Thus, the Electric Vehicle Programs O&M Totals do not equal the sum of the sub-project O&M Totals.

7.3. Rate Impact Analysis

The rate impact on residential customers from the active Utility 2.0 initiatives is illustrated in **Figure 7-1**. PSEG Long Island expects on average a low net increase in residential bills through 2026 as a result of the Utility 2.0 initiatives. This net increase is driven primarily by the EV Programs (Residential Charger Rebate Program) and the Residential Energy Storage System Incentive Program.

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

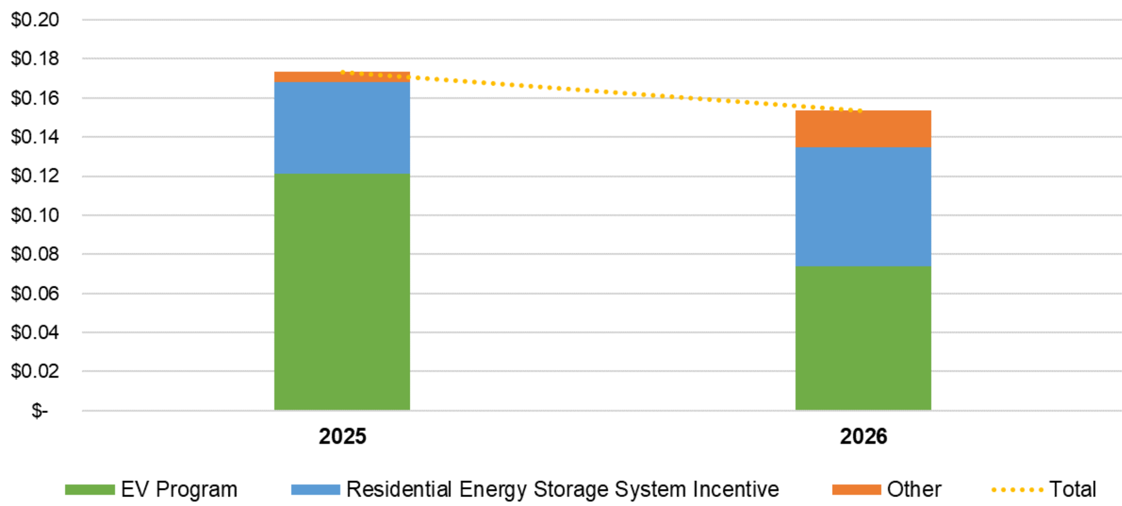

Table 7-4 and **Table 7-5** illustrate the estimated rate impact on residential and commercial customers, respectively. These rate impacts reflect the capital, O&M, net revenue change, and power supply costs for each active program, initiative, and project included in the 2024 Utility 2.0 Plan's funding requirements. A positive impact indicates an increase, and a negative impact indicates a decrease in the rates. It is important to note that values presented in the tables below are rounded to the hundredths decimal place.

Table 7-4. Residential Rate Impacts

Initiative	2025 ($)	2026 ($)
EV Programs[204]	0.12	0.07
Make-Ready Programs[205]	0.00	(0.02)
Connected Buildings Pilot	0.00	0.02
Suffolk County Bus Make-Ready Pilot	0.00	0.00
IEDR Platform	0.00	0.02
Residential Energy Storage System Incentive	0.05	0.06
Total	**0.17**	**0.15**

Table 7-5. Commercial Rate Impacts

Initiative	2025 ($)	2026 ($)
EV Programs[204]	0.93	0.57
Make-Ready Programs[205]	59.32	89.02
Connected Buildings Pilot	0.00	0.00
Suffolk County Bus Make-Ready Pilot	0.00	0.32
IEDR Platform	0.02	0.16
Residential Energy Storage System Incentive	0.00	0.00
Total	**60.27**	**90.06**

[204] EV Programs include the DCFC Program, Residential Charger Rebate Program, and EV Phase-In Rate
[205] Make-Ready Programs include the EV Make-Ready and the Fleet Make-Ready Program

Appendix

2024 Utility 2.0 Plan Annual Filing, Energy Efficiency Plan, and Five-Year Plan

Appendix A. 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 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)*.[206]

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 T&D capital investments ("Non-Wire Solutions").

A.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

A.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,

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[206] *BCA Order*: Case 14-M-0101, Order Establishing the Benefit Cost Analysis Framework (issued January 21, 2016).

a like for like comparison cannot necessarily always be completed for each aspect of a potential solution.

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 A-1** lists the statewide data and sources to be used for BCA and referenced in this Handbook.

Table A-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 A-2 lists the suggested utility-specific assumptions for the BCA Handbook.

Table A-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[207]
Restoration Costs	[Utility-specific]
Avoided Generation Capacity Cost (AGCC)	Utility-specific
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 A-1** and **Table A-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 be 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.

[207] 2020 Annual Electric Service Reliability Report

A.1.2 BCA Handbook Version

This 2023 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.

A.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 A.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 A.3 Relevant Cost-Effectiveness Tests** defines each cost-effectiveness test included in the BCA Framework. These include the Societal Cost Test (SCT), the Utility Cost Team (UCT), and the Rate Impact Measure (RIM). The *BCA Order* specifies the SCT as the primary measure of cost-effectiveness.
- **Section A.4 Benefits and Costs Methodology** provides detailed definitions, calculation methods, and general considerations for each benefit and cost.
- **Section A.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.
- **Utility-Specific Assumptions** includes value assumptions to be applied to the quantifiable energy and non-energy impacts of projects and portfolios.

A.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 A.4.**

A.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 A.2.1.1 and **A.2.1.2** discuss these considerations in more detail.

A.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.

A.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 A.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 A.4**. Two bulk system benefits, Avoided Generation Capacity Costs (AGCC) and Avoided ACEs, 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 T&D 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 CO2 and Net Avoided SO2 and NOx benefits calculations.

Table A-3 provides a list of potentially overlapping AGCC and Avoided ACE benefits

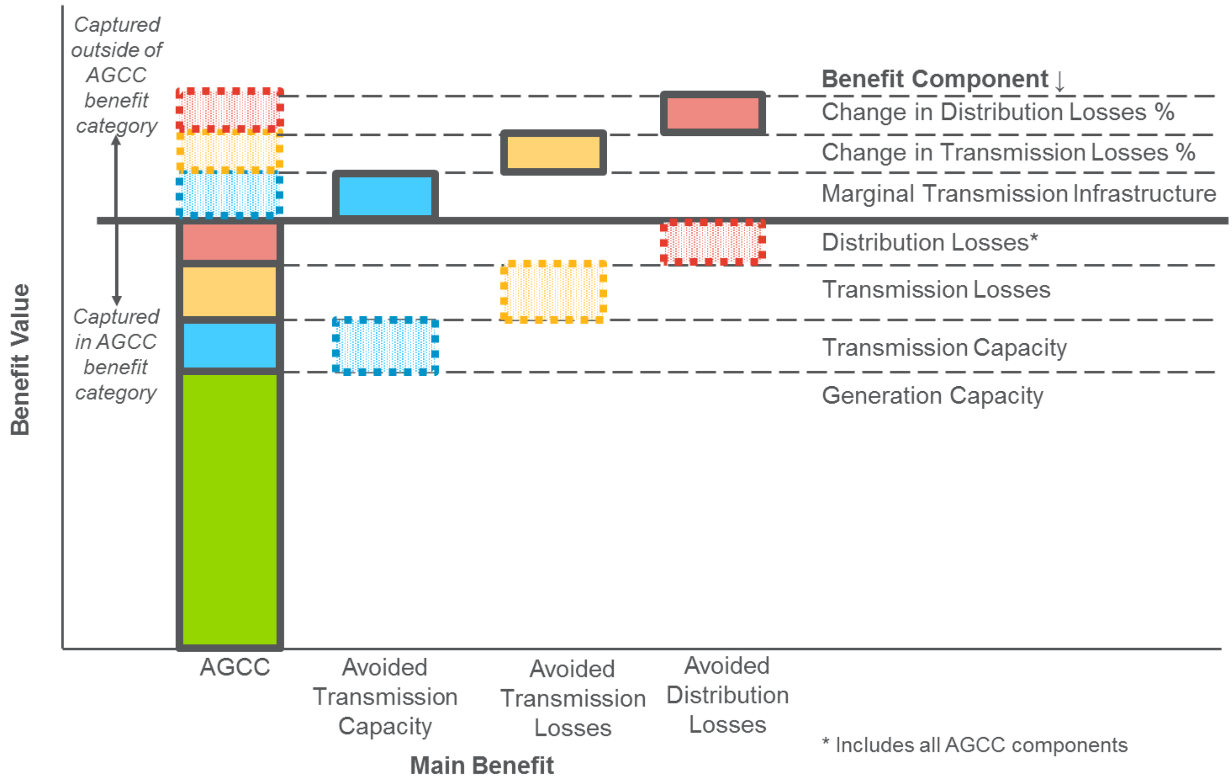
Table A-3. Benefits with Potential Overlaps

Main Benefits	Potentially Overlapping Benefits
Avoided Generation Capacity Costs (AGCC)	Avoided Transmission Capacity Infrastructure and Related O&M Avoided Transmission Losses Avoided Distribution Losses
Avoided ACEs (analogous to LBMP)	*Net Avoided* CO2 *Net Avoided SO2 and* NOx *Avoided Transmission* Losses *Avoided Transmission Capacity Infrastructure and Related O&M* Avoided *Distribution* Losses

Benefits Overlapping with Avoided Generation Capacity Costs

Figure A-1 graphically illustrates potential overlaps of benefits pertaining to the AGCC.

Figure A-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.[208] Additionally, distribution losses can affect the calculation of AGCC, depending on the project location on the system.[209] 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

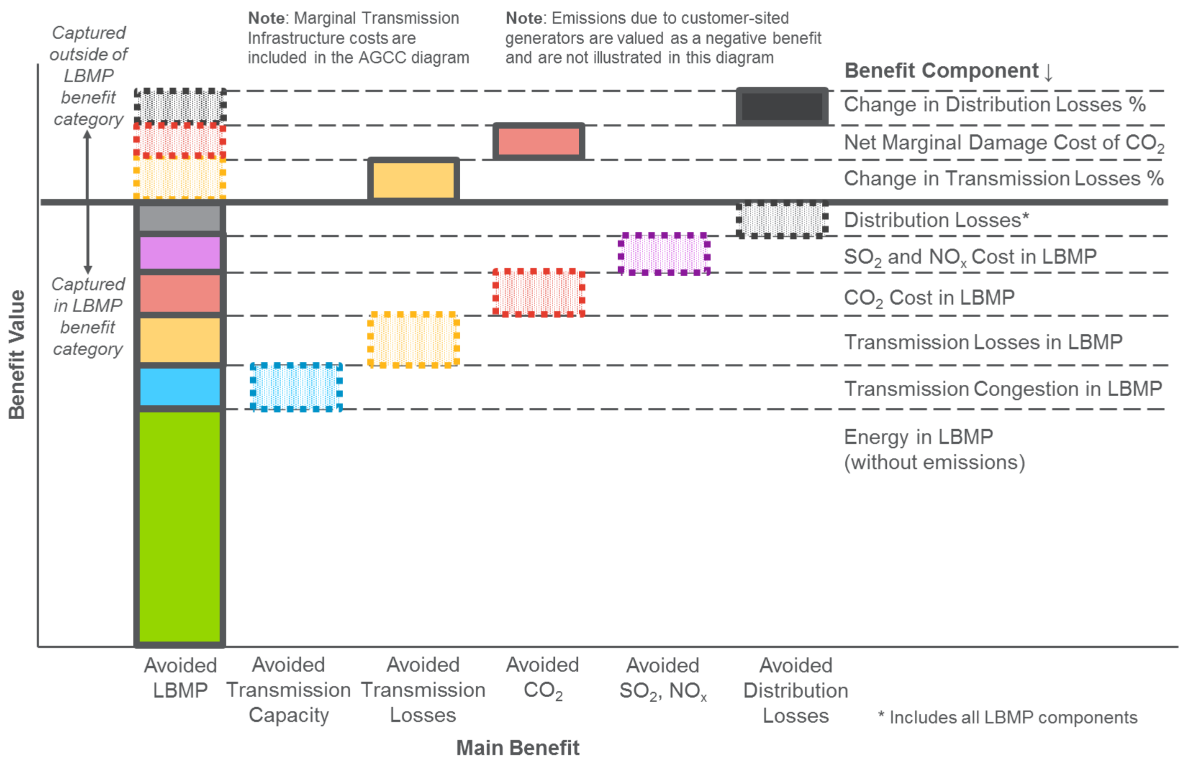
[208] The AGCC includes a portion of avoided transmission capacity infrastructure costs as zonal differences in the ICAP clearing price.
[209] For example, an impact on the secondary distribution system compared to the primary system will have a higher impact on the AGCC due to higher losses.

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 A-2 graphically illustrates potential overlaps of benefits pertaining to Avoided ACE.

Figure A-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 ACEs 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 ACEs 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.[210] 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 specifically impact Avoided Transmission Capacity Infrastructure and Related O&M or change the transmission loss percent. In these instances, the impacts would be captured outside of the Avoided ACEs benefit.

A.2.2 Incorporating Losses into Benefits

Many of the benefit equations provided in **Section A.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 A.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[211] 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 A.4** follow the same notation to represent various locations on the system:

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[210] 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.

[211] In the BCA equations outlined in the Benefits and Costs Methodology Section 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.

- "r" subscript represents the retail delivery point or point of connection of a DER, for example distribution secondary, distribution primary, or transmission[212]
- "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 $\mathrm{Loss\%}_{\mathrm{b}\rightarrow\mathrm{r}}$ 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.

A.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

[212] Transmission in this context refers to the distribution utility's sub-transmission and internal transmission.

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.

A.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.

A.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.[213]

A.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.

A.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."[214] As **Section A.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 ACEs or Avoided Generation Capacity Costs (AGCC)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 A-4.**

Table A-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);

[213] *BCA Order*, pg. 2
[214] *BCA Order*, Appendix C, pg. 31.

Cost Test	Perspective	Key Question Answered	Calculation Approach
			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.”[215]

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 A.2.**

Table A-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.

[215] *BCA Order*, pg. 13.

Table A-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 ACEs‡	✓	✓	✓
B.4.1.3	Avoided Transmission Capacity Infrastructure and Related O&M†‡	✓	✓	✓
B.4.1.4	Avoided Transmission Losses†‡	✓	✓	✓
B.4.1.5	Avoided Ancillary Services (Spinning Reserves, and Frequency Regulation)	✓	✓	✓
B.4.1.6	Wholesale Market Price Impact**		✓	✓
B.4.2.1	Avoided Distribution Capacity Infrastructure	✓	✓	✓
B.4.2.2	Avoided O&M	✓	✓	✓
B.4.2.3	Distribution Losses†‡	✓	✓	✓
B.4.3.1	Net Avoided Restoration Costs	✓	✓	✓
B.4.3.2	Net Avoided Outage Costs	✓		
B.4.4.1	Net Avoided CO2‡	✓		
B.4.4.2	Net Avoided SO2 and NOx‡	✓		
B.4.4.3	Avoided Water Impact	✓		
B.4.4.4	Avoided Land Impact	✓		
B.4.4.5	Net Non-Energy Benefits Related to Utility or Grid Operations***	✓	✓	✓
	Cost			
B.4.5.1	Program Administration Costs	✓	✓	✓

Section #	Benefit/Cost	SCT	UCT	RIM
B.4.5.2	Added Ancillary Service Costs	✓	✓	✓
B.4.5.3	Incremental Transmission & Distribution 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 Impact 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 Benefits Related to Utility or Grid Operations or Net Non-Energy Costs 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.

A.3.1 Societal Cost Test

Table A-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."[216]

[216] *BCA Order*, pg. 24

A.3.2 Utility Cost Test

Table A-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 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.

A.3.3 Rate Impact Measure

Table A-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 Net Avoided CO2, Net Avoided SO2 and NOx, and Avoided Water Impact and Avoided 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.

A.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,[217] 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,[218] it is assumed that impacts generate

[217] Energy, operational, and reliability-related benefits and costs include: Avoided ACEs, the energy component of Avoided Transmission Losses, Avoided Ancillary Services (Spinning Reserves, and Frequency Regulation), the energy portion of Wholesale Market Price Impact, Avoided O&M, Avoided Distribution Capacity Infrastructure, Net Avoided Restoration Costs, Net Avoided Outage Costs, the energy component of Distribution Losses, Net Avoided CO2, Net Avoided SO2 and NOx, Avoided Water Impact, Avoided Land Impact, Net Non-Energy Benefits Related to Utility or Grid Operations, Program Administration Costs, Participant DER Cost, Lost Utility Revenue, and Net Non-Energy Costs.

[218] Capacity, infrastructure, and market price-related benefits and costs include: Avoided Generation Capacity Costs (AGCC), the capacity component of Avoided Transmission Losses, Avoided O&M, the capacity component of Distribution Losses, Avoided Transmission Capacity Infrastructure and Related O&M, the capacity portion of the Wholesale Market Price Impact, Added Ancillary Service Costs, and Incremental Transmission & Distribution and DSP Costs.

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.

A.4.1 Bulk System Benefits

A.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.[219] 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 New York State 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 A-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.

[219] 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 A-1. Avoided Generation Capacity Costs (AGCC)

$$\text{Benefit}_{Y+1} = \sum_{Z} \frac{\Delta\text{PeakLoad}_{Z,Y,r}}{1\text{-Loss\%}_{Z,Y,b\rightarrow r}} * \text{SystemCoincidenceFactor}_{Z,Y} * \text{DeratingFactor}_{Z,Y} * \text{AGCC}_{Z,Y,b}$$

The indices of the parameters in

Equation A-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.

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 A-25.**

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.

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.[220] 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[221] 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 A.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

[220] 2019 CARIS Phase 1 Study Appendix. 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
[221] NYISO Installed Capacity Manual

values should be modeled and quantified in the Avoided T&D Losses and Avoided T&D Infrastructure benefits, below.

A.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.

Benefit Equation, Variables, and Subscripts

Equation A-2 presents the benefit equation for Avoided ACE:

Equation A-2. Avoided ACE

$$\mathrm{Benefit}_{\mathrm{Y}} = \sum_{\mathrm{Z}} \sum_{\mathrm{P}} \frac{\Delta \mathrm{Energy}_{\mathrm{Z,P,Y,r}}}{1 - \mathrm{Loss\%}_{\mathrm{Z,b \to r}}} * \mathrm{ACE}_{\mathrm{Z,P,Y,b}}$$

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 $Loss\%_{Z,b \to r}$ parameter. This input is project- or program-specific. A positive value represents a reduction in energy.

$\mathbf{Loss\%_{Z,b \to r}}$ (%) 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 A-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 A.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.

A.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 A-3 presents the benefit equation for Avoided Transmission Capacity Infrastructure and Related O&M:

Equation A-3. Avoided Transmission Capacity Infrastructure and Related O&M

$$\mathrm{Benefit}_{Y+1} = \sum_{C} \frac{\Delta \mathrm{PeakLoad}_{Y,r}}{\mathrm{Loss\%}_{Y,b \rightarrow r}} * \mathrm{TransCoincidentFactor}_{C,Y} * \mathrm{DeratingFactor}_{Y} * \mathrm{MarginalTransCost}_{C,Y,b}$$

The indices[222] of the parameters in **Equation A-3** presents the benefit equation for Avoided Transmission Capacity Infrastructure and Related O&M:

Equation A-3 include:

- C = constraint on an element of transmission system[223]
- Y = Year
- b = Bulk System
- r = Retail Delivery or Connection Point

$\boldsymbol{\Delta \mathrm{PeakLoad}_{Y,r}}$ **(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.

[222] In future versions of the Handbook, additional indices such as time period and voltage level can be included as this data becomes available.
[223] If system-wide marginal costs are used, this is not an applicable subscript.

$\mathbf{Loss\%_{Y,b \rightarrow r}}$ **(%)** is the variable loss percent between the bulk system ("b") and the retail delivery point ("r"). Thus, this reflects the sum of the T&D system loss percent values, both found in **Table A-25**.

$\mathbf{TransCoincidentFactor_{C,Y}}$ **(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.

$\mathbf{DeratingFactor_Y}$ **(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 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.

$\mathbf{MarginalTransCost_{C,Y,b}}$ **($/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 A-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 A-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 A.4.2.2**.

A.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 Generation Capacity Costs and ACE benefits as described above in **Sections A.4.1.1** and **A.4.1.2**. 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 A-4 presents the benefit equation for Avoided Transmission Losses:

Equation A-4. Avoided Transmission Losses

$$\text{Benefit}_{\text{Y+1}} = \sum_{\text{Z}} \text{SystemEnergy}_{\text{Z,Y+1,b}} * \text{ACE}_{\text{Z,Y+1,b}} * \Delta\text{Loss\%}_{\text{Z,Y+1,b}\rightarrow\text{i}} + \text{SystemDemand}_{\text{Z,Y,b}} * \text{AGCC}_{\text{Z,Y,b}} * \Delta\text{Loss\%}_{\text{Z,Y,b}\rightarrow\text{i}}$$

Where,

$$\Delta\text{Loss\%}_{\text{Z,Y,b}\rightarrow\text{i}} = \text{Loss\%}_{\text{Z,Y,b}\rightarrow\text{i,baseline}} - \text{Loss\%}_{\text{Z,Y,b}\rightarrow\text{i,post}}$$

The indices[224] of the parameters in **Equation A-4** include:

- Z = NYISO zone (for ACE: A → K; for AGCC: NYC, LHV, LI, ROS[225])
- Y = Year
- b = Bulk System
- i = Interface of the transmission and distribution systems

SystemEnergy$_{\text{Z,Y+1,b}}$ (MWh) is the annual energy forecast by NYISO in the Load & Capacity Report at the bulk system ("b"), which includes T&D 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.

ACE$_{\text{Z,Y+1,b}}$ ($/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 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.

SystemDemand$_{\text{Z,Y,b}}$ (MW) is the system peak demand forecast by NYISO at the bulk system level ("b"), which includes T&D losses by zone. Note that the system demand is used in this evaluation, not the project-specific demand, because this benefit is only quantified

[224] In future versions of the Handbook, additional indices such as time period and voltage level can be included as this data becomes available.
[225] Mapping NYISO localities to NYISO zones: ROS = A-F, LHV = G-I, NYC = J, LI = K

when the system topology is changed resulting in a change in transmission losses percent, which affects all load in the relevant zone.

$AGCC_{Z,Y,b}$ ($/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"[226] 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.

$\Delta Loss\%_{Z,Y,b\rightarrow i}$ (Δ%) is the change in fixed and variable loss percent between the bulk system ("b") and the interface of the T&D 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.

$Loss\%_{Z,Y,b\rightarrow i,baseline}$ (%) is the baseline fixed and variable loss percent between bulk system ("b") and the interface of the T&D systems ("i"). Thus, this reflects the sub-transmission and internal transmission losses pre-project, which is found in **Table A-25**.

$Loss\%_{Z,Y,b\rightarrow i,post}$ (%) is the post-project fixed and variable loss percent between bulk system ("b") and the interface of the T&D 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

[226] "Transmission level" represents the bulk system level ("b").

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.

A.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.

Frequency Regulation

Equation A-5 presents the benefit equation for frequency regulation:

Equation A-5. Frequency Regulation

$$\mathrm{Benefit}_Y = \mathrm{Capacity}_Y * n * (\mathrm{CapPrice}_Y + \mathrm{MovePrice}_Y * \mathrm{RMM}_Y)$$

The indices of the parameters in **Equation A-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 A-6 presents the benefit equation for spinning reserves:

Equation A-6. Spinning Reserves

$$\mathrm{Benefit_Y} = \mathrm{Capacity_Y} * \mathrm{n} * \mathrm{CapPrice_Y}$$

The indices of the parameters in **Equation A-6** include:

- Y = Year

$\mathbf{Capacity_Y}$ **(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.

$\mathbf{CapPrice_Y}$ **($/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.

A.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.[227] ACE impact will be calculated for each NYISO zone. AGCC price impacts are characterized using Staff's ICAP Spreadsheet Model.

Benefit Equation, Variables, and Subscripts

Equation A-7 presents the benefit equation for Wholesale Market Price Impact:

[227] *BCA Order*, Appendix C, pg. 8.

Equation A-7. Wholesale Market Price Impact

$$\text{Benefit}_{Y+1} = \sum_{Z} (1 \text{ - Hedging\%}) * (\Delta\text{ACEImpact}_{Z,Y+1,b} * \frac{\Delta\text{Energy}_{Z,Y+1,r}}{1 - \text{Loss\%}_{Z,b \to r}} + \Delta\text{AGCC}_{Z,Y,b} * \text{ProjectedAvailableCapacity}_{Z,Y,b})$$

The indices of the parameters in **Equation A-7** include:

- Z = NYISO zone (A → K[228])
- Y = Year
- b = Bulk System

$\text{Hedging\%}$ (%) 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.

$\Delta\text{ACEImpact}_{Z,Y+1,b}$ (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.

$\Delta\text{Energy}_{Z,Y+1,r}$ (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 $Loss\%_{Z,b \to r}$ parameter. A positive value represents a reduction in energy.

$\text{Loss\%}_{Y,b \to r}$ (%) 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 A-25**.

$\text{WholesaleEnergy}_{Z,Y,b}$ (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.

$\Delta\text{AGCC}_{Z,Y,b}$ (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

[228] Mapping NYISO localities to NYISO zones: ROS = A-F, LHV = G-I, NYC = J, LI = K

and “Demand” tab, respectively) due to the project.[229] The price impacts are based on the size and location of the project. A positive value represents a reduction in price.

$\text{ProjectedAvailableCapacity}_{Z,Y,b}$ **(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.

A.4.2 Distribution System Benefits

A.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 A-8 presents the benefit equation for Avoided Distribution Capacity Infrastructure:

[229] As in the AGCC benefit equation, System Coincidence Factors and Derating Factors adjust the maximum load reduction of the project.

Equation A-8. Avoided Distribution Capacity Infrastructure

$$\text{Benefit}_{Y} = \sum_{V}\sum_{C}\frac{\Delta\text{PeakLoad}_{Y,r}}{1-\text{Loss\%}_{Y,b\to r}} * \text{DistCoincidentFactor}_{C,V,Y} * \text{DeratingFactor}_{Y} * \text{MarginalDistCost}_{C,V,Y,b}$$

The indices of the parameters in **Equation A-8** include:

- C = Constraint on an element (e.g., pole-mounted transformer, distribution line, etc.) of the distribution system[230]
- V = Voltage level (e.g., primary, and secondary)
- Y = Year
- b = Bulk System
- r = Retail Delivery or Connection Point

$\boldsymbol{\Delta\text{PeakLoad}_{Y,r}}$ **(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.

$\boldsymbol{\text{Loss\%}_{Y,b\to r}}$ **(%)** is the variable loss percent between the bulk system (“b”) and the retail delivery point (“r”). Thus, this reflects the sum of the T&D system loss percent values, both found in **Table A-25**.This parameter is used to adjust the $\Delta\text{PeakLoad}_{Y,r}$ parameter to the bulk system level.

$\boldsymbol{\text{DistCoincidentFactor}_{C,V,Y}}$ **(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.

$\boldsymbol{\text{DeratingFactor}_{Y}}$ **(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.

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[230] In limited cases where use of system-wide marginal cost values is required, this subscript is not applicable.

$\text{MarginalDistCost}_{C,V,Y,b}$ **($/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 A-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 T&D 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 A-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 A-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 A.4.2.2**.

A.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 A-9 presents the benefit equation for Avoided O&M Costs:

Equation A-9. Avoided O&M

$$\mathrm{Benefit_Y} = \sum_{\mathrm{AT}} \Delta\mathrm{Expenses_{AT,Y}}$$

The indices of the parameters in **Equation A-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

$\boldsymbol{\Delta\mathrm{Expenses_{AT,Y}}}$ **(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 A.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.

A.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 A-10 presents the benefit equation for Avoided Distribution Losses:

Equation A-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[231] of the parameters in **Equation A-10** include:

- Z = NYISO zone (for ACE: A → K; for AGCC: NYC, LHV, LI, ROS[232])
- 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.

[231] In future versions of the Handbook, additional indices such as time period and voltage level can be included as this data becomes available.
[232] Mapping NYISO localities to NYISO zones: ROS = A-F, LHV = G-I, NYC = J, LI = K.

$\mathbf{ACE_{Z,Y,b}}$ **($/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.

$\mathbf{SystemDemand_{Z,Y,b}}$ **(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 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 T&D 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 T&D systems ("i") and the retail delivery point ("r"). Thus, this reflects the distribution loss percent pre-project, which is found in **Table A-25**.

$\mathbf{Loss\%_{Z,Y,i\rightarrow r,post}}$ **(%)** is the post-project fixed and variable loss percent between the interface of the T&D 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.

A.4.3 Reliability/Resiliency Benefits

A.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 A-11 presents the benefit equation for Net Avoided Restoration Costs:

Equation A-11. Net Avoided Restoration Costs

$$\text{Benefit}_Y = -\Delta\text{CrewTime}_Y * \text{CrewCost}_Y + \Delta\text{Expenses}_Y$$

Where,

$$\Delta\text{CrewTime}_{\text{Y}} = \#\text{Interruptions}_{\text{base,Y}} * (\text{CAIDI}_{\text{base,Y}} - \text{CAIDI}_{\text{post,Y}} * (1 - \%\text{ChangeSAIFI}_{\text{Y}}))$$

$$\%\text{ChangeSAIFI}_{\text{Y}} = \frac{\text{SAIFI}_{\text{base,Y}} - \text{SAIFI}_{\text{post,Y}}}{\text{SAIFI}_{\text{base,Y}}}$$

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 A-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.

$\boldsymbol{\Delta\text{CrewTime}_{\text{Y}}}$ **(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.

$\boldsymbol{\text{CrewCost}_{\text{Y}}}$ **($/hr)** is the average hourly outage restoration crew cost for activities associated with the project under consideration.

$\boldsymbol{\Delta\text{Expenses}_{\text{Y}}}$ **(Δ$)** are the average expenses (e.g., equipment replacement) associated with outage restoration.

$\boldsymbol{\#\text{Interruptions}_{\text{base,Y}}}$ **(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.

$\boldsymbol{\text{CAIDI}_{\text{base,Y}}}$ **(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.

$\boldsymbol{\text{CAIDI}_{\text{post,Y}}}$ **(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 A-12. Net Avoided Restoration Costs

$$\mathrm{Benefit_Y} = \mathrm{MarginalCost_{R,Y}}$$

The indices of the parameters in **Equation A-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.

A.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 A-13 presents the benefit equation for Net Avoided Outage Costs:

Equation A-13. Net Avoided Outage Costs

$$\mathrm{Benefit}_{\mathrm{Y}} = \sum_{\mathrm{C}} \mathrm{ValueOfService}_{\mathrm{C,Y,r}} * \mathrm{AverageDemand}_{\mathrm{C,Y,r}} * \Delta\mathrm{SAIDI}_{\mathrm{Y}}$$

Where,

$$\Delta\mathrm{SAIDI}_{\mathrm{Y}} = \mathrm{SAIFI}_{\mathrm{base,Y}} * \mathrm{CAIDI}_{\mathrm{base,Y}} - \mathrm{SAIFI}_{\mathrm{post,Y}} * \mathrm{CAIDI}_{\mathrm{post,Y}}$$

The indices of the parameters in **Equation A-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

$\mathrm{ValueOfService}_{\mathrm{C,Y,r}}$ ($/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.

$\mathbf{\Delta SAIDI_{Y}}$ **(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.[233] 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.

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[233] SAIDI = SAIFI * CAIDI

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.

A.4.4 External Benefits

A.4.4.1 Net Avoided CO_2

Net Avoided CO_2 accounts for avoided CO_2 due to a reduction in system load levels[234] or the increase of CO_2 from onsite generation. The CARIS forecast of ACE contains a cost of carbon based on the RGGI. 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 A-14 presents the benefit equation for Net Avoided CO_2:

Equation A-14. Net Avoided CO_2

$$\mathrm{Benefit}_Y = \mathrm{CO2Cost\Delta ACE}_Y - \mathrm{CO2Cost\Delta OnsiteEmissions}_Y$$

Where,

[234] 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.

$$\mathrm{CO2Cost\Delta ACE_Y} = \left(\frac{\Delta \mathrm{Energy_{Y,r}}}{1 - \mathrm{Loss\%_{Y,b \to r}}} + \Delta \mathrm{Energy_{TransLosses,Y}} + \Delta \mathrm{Energy_{DistLosses,Y}}\right) * \mathrm{NetMarginalDamageCost_Y}$$

$$\Delta \mathrm{Energy_{TransLosses,Y}} = \mathrm{SystemEnergy_{Y,b}} * \Delta \mathrm{Loss\%_{Y,b \to i}}$$

$$\Delta \mathrm{Energy_{DistLosses,Y}} = \mathrm{SystemEnergy_{Y,b}} * \Delta \mathrm{Loss\%_{Y,i \to r}}$$

$$\Delta \mathrm{Loss\%_{Z,Y,b \to i}} = \mathrm{Loss\%_{Z,Y,b \to i,baseline}} - \mathrm{Loss\%_{Z,Y,b \to i,post}}$$

$$\Delta \mathrm{Loss\%_{Z,Y,i \to r}} = \mathrm{Loss\%_{Z,Y,i \to r,baseline}} - \mathrm{Loss\%_{Z,Y,i \to r,post}}$$

$$\mathrm{CO2Cost\Delta OnsiteEmissions_Y} = \Delta \mathrm{OnsiteEnergy_Y} * \mathrm{CO2Intensity_Y} * \mathrm{SocialCostCO2_Y}$$

The indices of the parameters in **Equation A-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 A-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 A.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.

$\Delta\mathbf{Energy_{DistLosses,Y}}$ **(ΔMWh)** represents the change in energy lost on the distribution system due to the Avoided Distribution Losses benefit. Refer to **Section A.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.

$\Delta\mathbf{Loss\%_{Z,Y,b\rightarrow i}}$ **(Δ%)** is the change in fixed and variable loss percent between the interface between the bulk system ("b") and the interface between the T&D 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 T&D systems ("i"). Thus, this reflects the transmission loss percent pre-project, which is found in **Table A-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 T&D systems ("i"). Thus, this reflects the transmission loss percent post-project, which is found in **Table A-25**.

$\Delta\mathbf{Loss\%_{Z,Y,i\rightarrow r}}$ **(Δ%)** is the change in fixed and variable loss percent between the interface between the T&D 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 T&D systems ("i") and the retail delivery point ("r"). Thus, this reflects the distribution loss percent pre-project, which is found in **Table A-25**.

$\mathbf{Loss\%_{Z,Y,i \rightarrow r,post}}$ **(%)** is the post-project fixed and variable loss percent between the interface of the T&D systems ("i") and the retail delivery point ("r"). Thus, this reflects the distribution loss percent post-project, which is found in **Table A-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[235].

$\mathbf{SocialCostCO2_Y}$ **(\$ / 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."[236]

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[235] 1 metric ton = 1.10231 short tons
[236] *BCA Order*, Appendix C, 16.

A.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 A-15 presents the benefit equation for Net Avoided SO_2 and NO_x:

Equation A-15. Net Avoided SO_2 and NO_x

$$\mathrm{Benefit_Y} = \sum_{p} \mathrm{OnsiteEmissionsFlag_Y} * \mathrm{OnsiteEnergy_{Y,r}} * \mathrm{PollutantIntensity_{p,Y}} * \mathrm{SocialCostPollutant_{p,Y}}$$

The indices of the parameters in **Equation A-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.

$\mathbf{PollutantIntensity_{p,Y}}$ **(ton/MWh)** is average pollutant emissions rate of customer-sited pollutant-emitting generation. This is a project-specific input.

$\mathbf{SocialCostPollutant_{p,Y}}$ **($/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.

A.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.

A.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.

A.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.

A.4.5 Costs Analysis

A.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 A-16 presents the cost equation for Program Administration Costs:

Equation A-16. Program Administration Costs

$$\mathrm{Cost}_{\mathrm{Y}} = \sum_{\mathrm{M}} \Delta\mathrm{ProgramAdminCost}_{\mathrm{M,Y}}$$

The indices of the parameters in **Equation A-16** include:

- M = Measure
- Y = Year

$\Delta\mathbf{ProgramAdminCost}_{\mathbf{M,Y}}$ 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).

A.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 **Section A.4.1.5** on Avoided Ancillary Services (Spinning Reserves, and Frequency Regulation).

A.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 A.4.1.3** which discusses 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.

A.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 A-9** for the intermittent solar PV example calculated based on information provided in the E3's NEM Study for New York ("E3 Report").[237] 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 A-9. Solar PV Example Cost Parameters

Parameter	Cost
Installed Cost (2015$/kW-AC)[238]	4,430
Fixed Operating Cost ($/kW)	15

Note: These are default values that would be used unless the DER provider supports project-specific estimates.

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[239] 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

[237] 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.
[238] 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.
[239] EPA CHP Report available at: https://www.epa.gov/chp/chp-resources

from the Energy Information Administration Annual Energy Outlook[240] are used (see **Table A-10**).

Table A-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. [241]
2. **Variable:** EPA's estimate of a 100 kW reciprocating engine CHP system's non-fuel O&M costs.[242]

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 A-11**).

Table A-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.

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[240] https://www.eia.gov/outlooks/aeo/
[241] EPA CHP Report. pg. 2-15.
[242] EPA CHP Report. pg. 2-17.

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 A-12**).

Table A-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 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[243] are used. Delivered fuel prices are scaled to Long Island specific values reported by NYSERDA.[244,245] (see **Table A-13**).

Table A-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.

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243 https://www.eia.gov/outlooks/aeo/
244 https://www.nyserda.ny.gov/Researchers-and-Policymakers/Energy-Prices
245 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

A.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.

A.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.

A.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 A-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 A-14**).

Table A-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 A-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 A-15.**

Table A-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 hours). 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 A-16**.

Table A-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 ACEs	●	●	●	●
3	Avoided Transmission Capacity Infrastructure and Related O&M	◒	◒	◒	◒
4	Avoided Transmission Losses	○	○	○	○
5	Avoided Ancillary Services (Spinning Reserves, and Frequency Regulation)	○	○	○	○
6	Wholesale Market Price Impact	●	●	●	●
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 CO2	●	●	●	●
13	Net Avoided SO2 and NOx	●	●	●	●
14	Avoided Water Impact	○	○	○	○
15	Avoided Land Impact	○	○	○	○
16	Net Non-Energy Benefits Related to Utility or Grid Operations	○	○	○	○
	Costs				
17	Program Administration Costs	●	●	●	●
18	Added Ancillary Service Costs	○	○	○	○
19	Incremental Transmission & Distribution and DSP Costs	◒	◒	◒	○
20	Participant DER Cost	●	●	●	●
21	Lost Utility Revenue	●	●	●	●

#	Benefit/Cost	PV	CHP	DR	EE
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 A.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 A-17** identifies the parameters which are necessary to characterize DER benefits. As described in **Section A.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 A-17. Key parameter for quantifying how DER may contribute to each benefit

#	Benefit	Key Parameter
1	Avoided Distribution Capacity Infrastructure	**SystemCoincidenceFactor**
2	Avoided O&M	**∆Energy (time-differentiated)**
3	Avoided Distribution Losses	**TransCoincidenceFactor**
4	Net Avoided Restoration Costs	Limited or no applicability
5	Net Avoided Outage Costs	Limited or no applicability
6	Net Avoided CO2	**∆Energy (annual)** **∆AGCC**
7	Net Avoided SO2 and NOx	**DistCoincidenceFactor**
8	Avoided Water Impact	Limited or no applicability
9	Avoided Land Impact	Limited or no applicability
10	Net Non-Energy Benefits Related to Utility or Grid Operations	Limited or no applicability
11	Avoided Distribution Capacity Infrastructure	Limited or no applicability[246]
12	Avoided O&M	**CO_2Intensity** (limited to CHP)
13	Avoided Distribution Losses	**PollutantIntensity** (limited to CHP)
14	Net Avoided Restoration Costs	Limited or no applicability
15	Net Avoided Outage Costs	Limited or no applicability
16	Net Avoided CO2	Limited or no applicability

Table A-18 further describes the key parameters identified in **Table A-17**.

[246] A CHP system may be able to provide a Net Avoided Outage Costs benefit in certain system configurations.

Table A-18. Key parameters

Key Parameter	Description
Bulk System Coincidence Factor	Necessary to calculate the AGCC benefit.[247] 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[248]	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.[249]

[247] This parameter is also used to calculate the Wholesale Market Price Impact benefit.

A.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.

A.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 A-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 A-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

A.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

[248] 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 Avoided Transmission Capacity Infrastructure and Related O&M benefit, which incorporates incremental value beyond what is included in the Avoided Generation Capacity Costs (AGCC) and Avoided ACEs benefits.

[249] Note also that annual change in bulk system energy is used in the calculation of Wholesale Market Price Impact benefit.

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.

A.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).

A.5.2 Estimating Coincidence Factors

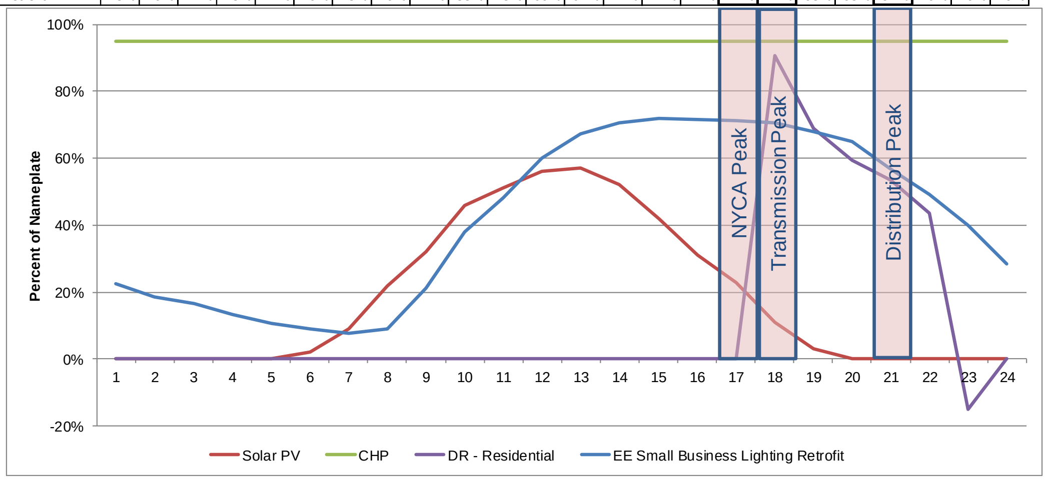
There are multiple approaches for estimating coincidence factors that apply different levels of rigor. Rigorous approaches could be defined and applied across a range of DERs; however, such an approach is likely to require a significant amount of granular information (e.g., 8760 hour load shapes for 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 A-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 A-3**).

Figure A-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.[250]

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

[250] 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.

example were calculated in E3's NEM Study for New York ("E3 Report")[251] 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.

A.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.

A.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, T&D.

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.

A.5.3.2 Benefit Parameters

The benefit parameters in **Table A-20** or the intermittent solar PV example are based on information provided in the E3 Report.

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**

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[251] 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.

A-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 A-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.[252] 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 A.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.[253] This value would be highly project-specific, as it depends on

[252] 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.
[253] 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.

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.

A.5.4 Combined Heat and Power Example

CHP is an example of a baseload DER which typically operates during system, transmission, and distribution peaks.

A.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).[254]

A.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.[255]

The carbon and criteria pollutant intensity can be estimated using the EPA's publicly available CHP Emissions Calculator.[256] "CHP Technology," "Fuel," "Unit Capacity" and

[254] https://www.epa.gov/chp/chp-resources
[255] EPA CHP Report. pg. 2-20.
[256] EPA CHP Emissions Calculator https://www.epa.gov/chp/chp-emissions-calculator

"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 A-21**).

Table A-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 A.4.1.1**).
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 A.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.

A.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.

A.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.[257] 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 hours). 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.

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.[258] 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 T&D

[257] Some DR programs may be “dispatched” or scheduled by third-party aggregators.
[258] Note, the controllable load may not be operating at the time of peak.

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.[259]

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.

A.5.5.2 Benefit Parameters

The benefit parameters described in **Table A-22** are assumed based on the example and considerations described above.

Table A-22. DR Example Benefit Parameters

Parameter	Value
SystemCoincidenceFactor	1.0
TransCoincidenceFactor	0.5
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.

[259] 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.

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.[260] 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.[261] 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.

A.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.[262]

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[260] 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.
[261] Ibid.
[262] 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 – Lighting operating hour data is sourced from the 2008 California DEER Update study.

A.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.[263] 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, T&D peak. This example of an indoor, office-setting lighting system assumes that the coincidence factor is calculated during operational 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 T&D peaks.

A.5.6.2 Benefit Parameters

The benefit parameters described in **Table A-23** were developed using guidance from the NY TRM.

Table A-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.

[263] Ibid.

4. **ΔEnergy (time-differentiated):** This value is calculated using the lighting hours per year (3,013) as provided for General Office types[264] 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.

A.6 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 A.4**. The discount rate is set by LIPA and reflects the PSEG Long Island cost of capital, which is included in **Table A-24**.

Table A-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 A-25**.

Table A-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 A-26.** The avoided carbon costs are incremental to the carbon coefficient embedded in the avoided marginal energy costs.

[264] 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 A-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	0.043	61.50	0.02741
2025	0.047	47.86	0.02741
2026	0.041	38.36	0.02741
2027	0.040	83.21	0.02741
2028	0.041	84.20	0.02741
2029	0.041	110.76	0.02741
2030	0.033	15.43	0.02741
2031	0.033	11.76	0.02741
2032	0.032	9.16	0.02741
2033	0.032	6.97	0.02741
2034	0.032	5.35	0.02741
2035	0.031	4.18	0.02741
2036	0.031	3.20	0.02741
2037	0.034	2.42	0.02741
2038	0.033	1.86	0.02741
2039	0.036	1.41	0.02741
2040	0.039	1.08	0.02741
2041	0.033	0.81	0.02741
2042	0.035	0.61	0.02741
2043	0.036	0.46	0.02741

Source: PSEG Long Island Utility 2.0 Plan, July 2024

A.7 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	Utility Cost Test

Appendix B. 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 considered active within the Utility 2.0 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 B-1** defines all project status designations assigned to Utility 2.0 initiatives as created by the PMO in 2022.

Table B-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. By the end of 2023, two additional initiatives completed their scope and objectives within the Utility 2.0 Program and transitioned to Operational status effective January 1, 2024. At the time of the 2024 Utility 2.0 Plan submission, no 2024 Active projects are expected to transition into Operational status in 2025.

Although the original scope of these initiatives was met, these initiatives have ongoing budgetary requirements to maintain, support, improve, and continue to operate services. Moving forward, 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 B-2**. Initiatives are organized based on historical Utility 2.0 priority areas.

Table B-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	
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	• Super Savers Patchogue	• EV + Storage Hosting Capacity Maps	• DER Visibility Platform

Orange Text: Completed Utility 2.0 Initiatives

The following subsections detail a high-level summary of the two initiatives that transitioned into Operational status at the beginning of 2024 (EV + Storage Hosting Capacity Maps and the DER Visibility Platform) and the one initiative that was completed at the end of 2023 (Super Savers Patchogue).

EV + Storage Hosting Capacity Maps

The purpose of the EV + Storage Hosting Capacity Maps project was to build on the successful deployment of the Stage 3 Hosting Capacity Maps from 2021 and provide insights into potential favorable locations to interconnect storage and EV resources. PSEG Long Island went live with both the Energy Storage Hosting Capacity and the Electric Vehicle Load Capacity Maps on the PSEG Long Island website by the end of 2023. Ongoing maintenance of the maps will be required in order to evolve the maps with changes in T&D criteria and to integrate any advances in the analytical tools used in the maps.

DER Visibility Platform

The purpose of the DER Visibility Platform was to enable distribution operators to manage DER under different system conditions and to provide additional capabilities such as control over the DER status, visualization of DER output, and accommodation of other controls and data through Distribution Supervisory Control and Data Acquisition (DSCADA). The Platform was completed by the end of 2023. O&M funding through the Core PSEG Long Island Budget in 2024 and 2025 (outside of the Utility 2.0 Program) will be required to support ongoing updates and maintenance to the Platform and to integrate any tool advancement capabilities.

Super Savers Patchogue

The purpose of the Super Savers Patchogue program was to increase adoption of Energy Efficiency measures and Demand Response program participation. Project enrollment initiated on August 1, 2020, and the last commercial projects were completed by September 30, 2023. No other activity for this project is expected in 2024 or 2025. Ongoing maintenance and savings of the Demand Response program will be maintained through September 30, 2025. Demand Response payments to the implementation contractor for provided load relief will be made through 2025 at the end of each capability period. This capability period runs from May 1st through September 30th in 2024 and 2025. PSEG Long Island will continue to report on quarterly aggregated payments in the Quarterly Report that is submitted to the DPS in order to satisfy a DPS request.

Appendix C. 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.

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.

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.

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 PSEG Long Island ManageCo that contains the senior management personnel and ServeCo that contains the balance of the employees. By design, ManageCo is in place as long as PSEG Long Island remains in the role of Service Provider, while ServeCo is directed by ManageCo, and would remain in place to support a successor Service Provider.

New York Department of Public Service (DPS)

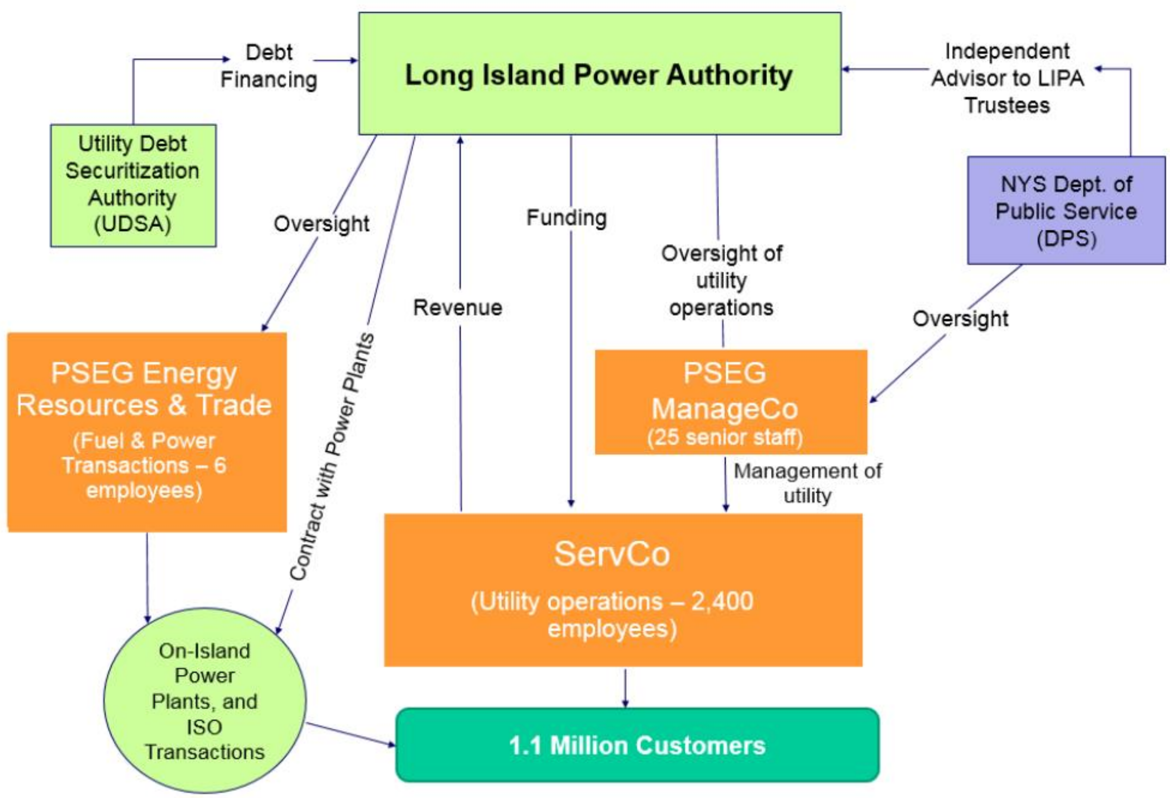
The New York Department of Public Service (DPS), as the state utility regulator and implementing agency for REV, plays a vital advisory role with respect to PSEG Long Island's annual Utility 2.0 Plan review. The amended LIPA Reform Act requires LIPA to submit its annual Utility 2.0 Plan to the New York 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 Second A&R OSA, 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.

LIPA's Public-Private Partnership Structure

Figure C-1 depicts LIPA's Public-Private Partnership Structure.

Figure C-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 the First and Second A&R OSA[265]
- Customer Experience and Satisfaction within the First and Second A&R OSA
- EE and Distributed Generation within the First and Second A&R OSA
- Administers Power Supply and Clean Energy Standard Procurements

[265] See First A&R OSA and Second A&R OSA.

Appendix D. Acronyms and Abbreviations

ACC	Advanced Clean Car
ACT	Advanced Clean Trucks
AGCC	Avoided Generation Capacity Cost
AMI	Advanced Metering Infrastructure
ASHP	Air Source Heat Pump
BE	Beneficial Electrification
BEEM	Building Efficiency and Electrification Model
BCA	Benefit-Cost Analysis
BESS	Bulk Energy Storage System
BOMA	Building Owners and Management Association
BPI	Building Performance Institute
BTM	Behind-the-Meter
Btu	British thermal unit
C&I	Commercial and Industrial
CEP	Commercial Efficiency Program
CIAC	Contribution in Aid of Construction
CJWG	Climate Justice Working Group
Climate Act or CLCPA	Climate Leadership and Community Protection Act
CMCP	Commercial Managed Charging Program
CO_2	Carbon Dioxide
COMP	Customer Outreach and Marketing Plan

CPP	Community Partnership Program
CRM	Customer Relationship Management
CS-MR	Customer-Side Make-Ready
CSRP	Commercial System Relief Program
CVR	Conservation Voltage Reduction
DAC	Disadvantaged Community
DAF	Data Access Framework
DCFC	Direct Current Fast Charging
DCR	Demand Charge Rebate
DEC	Department of Environmental Conservation
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
DRV	Demand Reduction Value
DSA	Demand Side Analytics
DSCADA	Distribution Supervisory Control and Data Acquisition
DSP	Distributed System Platform
EC	Energy Consultant

EE	Energy Efficiency
EEP	Energy Efficient Products
EFS	Energy Finance Solutions
EISA	Energy Independence and Security Act
EPA	Environmental Protection Agency
EV	Electric Vehicle
EVMR	Electric Vehicle Make-Ready Program
EVSE	Electric Vehicle Supply Equipment
FTE	Full-Time Employee
FTM	Front-of-the-Meter
GHG	Greenhouse Gas
GIS	Geographic Information System
GSHP	Ground Source Heat Pump
HEA	Home Energy Assessment
HEAP	Home Energy Assistance Program
HEAT	Home Energy Affordability
HEM	Home Energy Management
HPwES	Home Performance with Energy Star
HPWH	Heat Pump Water Heater
HVAC	Heating, Ventilation, and Air Conditioning
IR	Interrogatory Request
ISC	Index Storage Credit
IT	Information Technology

IVR	Interactive Voice Response
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
LIBI	Long Island Building Institute
LILCO	Long Island Lighting Company
LIPA	Long Island Power Authority
LMI	Low-to-Moderate Income
LWT	Leaving Water Temperature
m	Meter
MAC	Major Account Consultant(s)
M&V	Measurement and Verification
MF	Multifamily
MHDV	Medium- and Heavy-Duty Vehicle(s)
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
OLA	Online Application
OSA	Operations Services Agreement
O&M	Operations and Maintenance
PA	Program Agreement
PEP	Prime Efficiency Partner(s)
PHEV	Plug-in Hybrid Electric Vehicle
PIP	Project Implementation Plan
PMO	Program Management Office
POP	Point of Purchase
POS	Point-of-Sale
PSEG	Public Service Enterprise Group Incorporated
PV	Photovoltaic
QIV	Quality Installation Verification
QPL	Qualified Products List
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
SMI	State Median Income
TA	Technical Assistance
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
VCD	Verification Code of Documents
VDER	Value of Distributed Energy Resources
VRF	Variable Refrigerant Flow
ZEV	Zero-Emission Vehicle