Connecticut Energy Storage Solutions – Year 6 Evaluation, Measurement, and Verification (EM&V) Report

Prepared for:

energy storage SOLUTIONS

CONNECTICUT GREEN BANK

EVERSOURCE

UI An Avangrid company

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Analyze • Simplify • Implement

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Table of Contents

Executive Summary 4
1. Introduction 9
  1.1. Program Background and Objectives 9
  1.2. Overview of Program Design 10
  1.3. Annual Report Requirements and Objectives 15
  1.4. Program Metrics Overview 15
2. Data Sources and Data Review 15
  2.1. Data from Program Administrators 16
  2.2. Telemetry Data 16
  2.3. Data Review 17
  2.4. Findings and Recommendations 18
3. Program Tracking Metrics 18
  3.1. Program Tracking Categorization 18
  3.2. Program Tracking Metrics 21
  3.3. Findings and Recommendations 42
4. Program Evaluation Metrics 43
  4.1. Program Evaluation Metrics 43
  4.2. Findings and Recommendations 59
5. Benefit-Cost Analysis 60
  5.1. Benefit-Cost Model – Design and Use 60
  5.2. Benefit-Cost Model Inputs 63
  5.3. BCA Metrics 70
  5.4. Findings and Recommendations 75
6. Key Findings and Recommendations 75
  6.1. Key Findings 76
  6.2. Recommendations 76

List of Tables

Table ES-1. Count of Participants by Project Status, Customer Type, and Utility 6
Table ES-2. Total Power Capacity (MW) by Project Status 7
Table ES-3. Progress Made Toward Program Capacity Goals 8

Table 1-1. ESS MW Goals by Tranche 10
Table 1-2. Residential Upfront Incentive Levels (Legacy) 11
Table 1-3. Commercial Upfront Incentive Levels (Legacy) 11
Table 1-4. Updated Passive Dispatch Scoring Methodology 12
Table 1-5. Construct 5 Enrollment Incentives 13
Table 1-6. Construct 5 Performance Incentives 14
Table 1-7. Active Dispatch Parameters 14
Table 2-1. Data Availability and QC Findings and Recommendations 18
Table 3-1. Project Stage Categories 19
Table 3-2. Residential Project Categories 20
Table 3-3. Commercial Project Categories 21
Table 3-4. ESS Participants (Number and Percentage of Total) 22
Table 3-5. Share of Low-Income & Underserved Residential Participants 23

Table 3-6. Indication of Participation in the ISO-NE FCM for C&I Participants 24
Table 3-7. Project Approval Rates 25
Table 3-8. Average Days to Approve and Complete Project Application 26
Table 3-9. Share of Energy Storage Paired with PV 27
Table 3-10. Total Allocated Power Capacity (kW) by Project Status 28
Table 3-11. Total Allocated Energy Capacity (kWh) by Project Status 29
Table 3-12. Average Project Size 30
Table 3-13. Number of Systems and Batteries by Manufacturer 31
Table 3-14. Number of Approved or Completed Applications by Contractor 32
Table 3-15. Program Administrative Costs ($) 34
Table 3-16. Estimated Upfront Incentives Encumbered by Project Status ($) 35
Table 3-17. Average Total Project Upfront Incentive for Legacy Projects ($/Participant) 36
Table 3-18. Average Total Project Upfront Incentive for Construct 5 Projects ($/Participant) 37
Table 3-19. Average Project Cost ($/Participant) 38
Table 3-20. Total Installed Costs Allocated to Participants by Project Status ($) 39
Table 3-21. Average Total Energy Storage System Costs ($/kWh and $/kW) 40
Table 3-22. Average Battery-Only Costs ($/kWh and $/kW) 42
Table 3-23. Program Tracking Metrics Findings and Recommendations 42
Table 4-1. Residential Program Evaluation Metrics by Active Event Date-Summer 2025 Season 45
Table 4-2. Residential Program Evaluation Metrics by Active Event Date-Winter 2025-2026 Season 47
Table 4-3. Residential Program Evaluation Metrics by Passive Event Date Summer 2025 47
Table 4-4. C&I Program Evaluation Metrics by Active Event Date - Summer 2025 Season 49
Table 4-5. C&I Program Evaluation Metrics by Active Event Date – Winter 2025-2026 Season .. 51
Table 4-6. C&I Program Evaluation Metrics by Passive Event Date Summer 2025 52
Table 4-7. Evaluation Metrics by Seasonal Peak Event 54
Table 4-8. Peak Targeting Percentages 55
Table 4-9. Active Events on Top 30 Load Days by Season 56
Table 4-10. Battery Performance Metric 57
Table 4-11. Emissions Evaluation Metrics 58
Table 4-12. Outage Metrics 58
Table 5-1. BCA Cost Tests 62
Table 5-2. Project Size and Cost Assumptions 64
Table 5-3. Residential and C&I Legacy Upfront Incentive Levels ($/installed kWh) 65
Table 5-4. Assumed Residential and C&I Enrollment Incentive Levels ($/installed kWh) 65
Table 5-5. Average System Max Expected Peak Reduction 67
Table 5-6. Program Deployment Targets (MW) 67
Table 5-7. Projected Program Enrollment (MW) 68
Table 5-8. Actual (through 2025) and Projected Program Administration Costs ($) 69
Table 5-9. Benefits Inputs Sources 70
Table 5-10. BCA Findings and Recommendations 75

List of Figures

Figure 3-1. Average Total Energy Storage System by Application Year ($/kWh) 41
Figure 5-1. Overall Program BCA 72

Figure 5-2. Residential Program BCA 73
Figure 5-3. C&I Program BCA 74
Figure 5-4. Overall Program BCA - AESC Counterfactual 6 75

Executive Summary

The Energy Storage Solutions (ESS) program, administered by the Connecticut Green Bank, Eversource, and the United Illuminating Company (UI), collectively known as the Program Administrators (PAs), provides incentives to support the development and beneficial operation of behind-the-meter (BTM) energy storage systems in Connecticut. In this report, filed in Docket No. 26-08-05, the Annual Energy Storage Solutions Program Review – Year 6 proceeding, Customized Energy Solutions, Inc. (CES) provides an evaluation of the Program, including program enrollment through June 30, 2026, battery performance through March 31, 2026, benefit cost analysis, and resulting findings and recommendations. This report is the first to be issued since the implementation of Construct 5, as directed by PURA in its Final Decision in Docket No. 26-08-05 – these changes are reflected in the report. Year 6 represents a critical transition period for the ESS Program, reflecting both significant growth in residential deployment and the implementation of Construct 5 program modifications directed by PURA. It is challenging to draw conclusions about the implications of the transition to Construct 5, given how recently it was implemented. At the same time, some early indications are concerning: for example, as of the completion of this report, no new commercial applications have been filed under Construct 5. Given how much commercial projects are projected to contribute to the programs' overall MW deployment goals, any slowdown in the commercial pipeline will challenge the ability of the program to achieve these program-level goals.

As of June 30, 2026, the ESS Program has enrolled 1,885 participants (see Table ES-1), up from 1,000 as of the same date last year. The number of completed projects has nearly tripled, from 462 to 1,398, while the number of approved projects has decreased modestly, from 533 to 487. For residential projects, this decrease is attributable to the number of projects reaching complete status exceeding the number of new enrollments; for commercial projects, canceled projects also contribute to the decrease. Eversource territory accounts for roughly 81% of participants (1,553) and United Illuminating (UI) territory for roughly 19% (370); UI's share is driven substantially by a single affordable multifamily hybrid project, counted as 161 participants. On a capacity basis, submitted, approved, and completed projects total 155.4 MW, of which 21.8 MW (14%) is residential, and 133.6 MW (86%) is C&I. The MW volume of completed projects has also roughly tripled, driven almost exclusively by residential projects. Measured against the Program's 2030 capacity goals, completed residential capacity (17.6 MW) represents 11.7% of the 150 MW residential goal, while completed C&I capacity (1.3 MW) represents just 0.3% of the 430 MW C&I goal, reflecting the continued stagnation of the commercial pipeline discussed below.

The performance of enrolled projects during program events also continues to improve, as outlined in **Section 4**. The Program Administrators have worked with OEMs to substantially improve residential battery performance, yielding improved participation rates, higher state of charge at the beginning of events, and increased percent of available energy discharged during the event. Because performance is driven largely by how OEMs respond to dispatch signals, targeted improvement with a small number of high-volume OEMs has meaningfully improved program-wide results. These improvements are particularly important because the value of distributed battery storage depends not only on installed capacity, but also on the ability of enrolled resources to reliably respond during periods of system need. These improvements have been seen in both active and passive event performance. The Program Administrators have also made progress improving the quality of telemetry data, though data quality challenges, for both enrollment and telemetry data, persist. Continued improvement in telemetry accuracy and data completeness will remain important to ensure reliable performance verification and accurate

quantification and reporting of program benefits. The program continues to evolve with the rollout of the Construct 5 incentive structure, effective April 1, 2026.

CES also updated the Program's benefit-cost analysis (BCA). The overall program Ratepayer Impact Measure (RIM) is 1.55, indicating the program continues to provide a net benefit to ratepayers, though this is a modest decrease from the BCA analysis filed in last year's EM&V report (1.69), driven primarily by changes in projected MW deployment and assumed project costs. The residential BCA shows improvement across all tests: the residential RIM increased to 1.18 and the Participant Cost Test (PCT) improved to 0.81, driven principally by changes (namely, improvements) in projected performance during active events. As with any prospective analysis, the results remain sensitive to assumptions regarding future battery deployment, event performance, avoided system costs, and project economics.

Several challenges warrant continued attention. The commercial (C&I) pipeline remains stymied by both a dearth of new applications and the slow pace of approved projects reaching commercial operation, leaving the program far short of its C&I capacity goal. The program also continues to fall short of its target of 40% participation by residential Low-Income and Underserved customers; a single affordable multifamily project accounts for a significant share of the Low-Income participants counted to date. Given current deployment trends, achieving the Program's 580 MW by 2030 target may require additional program design modifications, market interventions, or other adjustments. At the same time, any additional changes must be weighed against the value of program stability.

Overall, Year 6 demonstrates continued progress in residential adoption, meaningful improvements in battery performance during dispatch events, and continued evidence of program cost-effectiveness. However, achieving the Program's long-term objectives will require increased C&I deployment, continued improvement in battery performance and telemetry quality, broader participation among Low-Income and Underserved customers, and successful implementation of Construct 5 enhancements.

The **tables below**, which consider cumulative program capacity through June 30, 2026, provide summary enrollment statistics. More detailed discussion of evaluated metrics, findings, and recommendations is provided in the body of this report.

Table ES-1. Count of Participants by Project Status, Customer Type, and Utility

Utility	Customer Type	Project Status as of June 30, 2026			
		Submitted	Approved	Completed	Total
Eversource	Residential Standard	23 (10\0\13)	139 (1\106\32)	1055 (132\612\311)	**1217 (143\718\356)**
	Residential Underserved	9 (4\0\5)	33 (0\31\2)	133 (7\103\23)	**175 (11\134\30)**
	Residential Low-Income	0 (0\0\0)	32 (0\31\1)	69 (0\56\13)	**101 (0\87\14)**
	Residential Subtotal	***32 (14\0\18)***	***204 (1\168\35)***	***1257 (139\771\347)***	***1493 (154\939\400)***
	Small C&I	0 (0\0\0)	8 (0\8\0)	4 (0\4\0)	**12 (0\12\0)**
	Medium C&I	0 (0\0\0)	17 (0\17\0)	0 (0\0\0)	**17 (0\17\0)**
	Large C&I	0 (0\0\0)	28 (0\28\0)	3 (0\3\0)	**31 (0\31\0)**
	C&I Subtotal	***0 (0\0\0)***	***53 (0\53\0)***	***7 (0\7\0)***	***60 (0\60\0)***
	Eversource Subtotal	**32 (14\0\18)**	**257 (1\221\35)**	**1264 (139\778\347)**	**1553 (154\999\400)**
United Illuminating	Residential Standard	5 (4\0\1)	19 (0\18\1)	97 (30\65\2)	**121 (34\83\4)**
	Residential Underserved	1 (0\0\1)	27 (0\26\1)	34 (11\22\1)	**62 (11\48\3)**
	Residential Low-Income	0 (0\0\0)	175 (0\175\0)	0 (0\0\0)	**175 (0\175\0)**
	Residential Subtotal	***6 (4\0\2)***	***221 (0\219\2)***	***131 (41\87\3)***	***358 (45\306\7)***
	Small C&I	0 (0\0\0)	2 (0\2\0)	0 (0\0\0)	**2 (0\2\0)**
	Medium C&I	0 (0\0\0)	2 (0\2\0)	3 (0\3\0)	**5 (0\5\0)**
	Large C&I	0 (0\0\0)	5 (0\5\0)	0 (0\0\0)	**5 (0\5\0)**
	C&I Subtotal	***0 (0\0\0)***	***9 (0\9\0)***	***3 (0\3\0)***	***12 (0\12\0)***
	UI Subtotal	**6 (4\0\2)**	**230 (0\228\2)**	**134 (41\90\3)**	**370 (45\318\7)**
Total Number of Residential Participants		**38 (18\0\20)**	**425 (1\387\37)**	**1388 (180\858\350)**	**1851 (199\1245\407)**
Total Number of C&I Participants		**0 (0\0\0)**	**62 (0\62\0)**	**10 (0\10\0)**	**72 (0\72\0)**
Total Number of Participants		**38 (18\0\20)**	**487 (1\449\37)**	**1398 (180\868\350)**	**1923 (199\1317\407)**

Note: Values in parentheses are reported as Only Active participants \ Active & Passive participants \ Construct 5 participants, respectively. "Total" column represents the sum of submitted, approved, and completed projects, excluding any cancelled and pipeline projects, as defined in Section 3.1.1. The hybrid project, detailed in Section 3.1.5, is counted as 161 participants under United Illuminating's Residential Low-Income and 1 participant under United Illuminating's Large C&I. All other applications are counted as one participant each. Note that the values in this and most tables in this report include projects transferred from ConnectedSolutions, as discussed in Section 3.2.

***Source**: Customized Energy Solutions analysis of Connecticut Green Bank program tracking data through June 30, 2026.*

Table ES-2. Total Power Capacity (MW) by Project Status

Utility	Customer Type	Project Status as of June 30, 2026			
		Submitted	Approved	Completed	Total
Eversource	Residential Standard	0.28	2.09	13.87	**16.24**
	Residential Underserved	0.09	0.39	1.64	**2.11**
	Residential Low-Income	0.00	0.26	0.65	**0.91**
	Residential Subtotal	***0.37***	***2.74***	***16.16***	***19.26***
	Small C&I	0.00	6.09	0.63	**6.71**
	Medium C&I	0.00	27.86	0.00	**27.86**
	Large C&I	0.00	86.84	0.51	**87.34**
	C&I Subtotal	***0.00***	***120.78***	***1.13***	***121.91***
	Eversource Subtotal	**0.37**	**123.52**	**17.29**	**141.18**
United Illuminating	Residential Standard	0.03	0.29	1.08	**1.41**
	Residential Underserved	0.01	0.24	0.32	**0.57**
	Residential Low-Income	0.00	0.58	0.00	**0.58**
	Residential Subtotal	***0.04***	***1.11***	***1.40***	***2.55***
	Small C&I	0.00	0.76	0.00	**0.76**
	Medium C&I	0.00	2.27	0.15	**2.42**
	Large C&I	0.00	8.51	0.00	**8.51**
	C&I Subtotal	***0.00***	***11.54***	***0.15***	***11.70***
	UI Subtotal	**0.04**	**12.65**	**1.56**	**14.25**
Total Power Capacity: Residential (MW)		**0.41**	**3.84**	**17.56**	**21.82**
Total Power Capacity: C&I (MW)		**0.00**	**132.32**	**1.29**	**133.61**
Total Power Capacity (MW)		**0.41**	**136.17**	**18.85**	**155.43**

Note: The "Total" column reflects the sum of submitted, approved, and completed projects, and excludes any cancelled and pipeline projects, as defined in Section 3.1.1. The hybrid project's capacity, detailed in Section 3.1.5, has been proportionally allocated: **48%** to United Illuminating's Residential Low-Income and **52%** to United Illuminating's Large C&I, based on guidance from the Connecticut Green Bank. Some totals and subtotals above may be different than the sum of applicable values due to rounding errors.

Source: *Customized Energy Solutions analysis of Connecticut Green Bank program tracking data through June 30, 2026.*

Table ES-3. Progress Made Toward Program Capacity Goals

Sector	Submitted (MW)	Approved (MW)	Completed (MW)	Total (MW)	Program Goals (2022-2030) (MW)	Percentage of Complete Capacity Relative to Goal as of June 30, 2026
Residential	0.4	3.8	17.6	21.8	150	11.7%
C&I	0.0	132.3	1.3	133.6	430	0.3%

Note: As outlined in Section 3.1.5, the hybrid project has been proportionally allocated, with 48% of its capacity classified under Residential and 52% under C&I, in accordance with guidance from the Connecticut Green Bank. As of June 30, 2025, this project remains in the "Approved" stage and is not yet marked as "Complete."

Source: *Customized Energy Solutions analysis of Connecticut Green Bank program tracking data through June 30, 2026.*

1. Introduction

1.1. Program Background and Objectives

Background and Regulatory Framework

The Energy Storage Solutions Program is Connecticut's statewide initiative to support the deployment of distributed (specifically, behind the meter or BTM) battery energy storage systems (BESS), launched after the enactment of Public Act 21-53. This legislation established statewide energy storage deployment targets of 300 MW by 2024, 650 MW by 2027, and 1,000 MW by 2030.[1] **Section 2** of the Act directed the Public Utilities Regulatory Authority (PURA) to develop and implement one or more programs to achieve these goals, including the establishment of appropriate funding mechanisms and administrative structures.

On July 28, 2021, the Authority issued a final decision in Docket No. 17-12-03RE03[2], which formally established the ESS program as a nine-year initiative, beginning January 1, 2022 and continuing through at least December 31, 2030. The program is administered by the Connecticut Green Bank and Connecticut's two electric distribution companies, Eversource and United Illuminating, collectively referred to as the Program Administrators. Under PURA oversight, the Program Administrators are tasked with designing and delivering incentives for both residential and C&I customers, with the objective of deploying BTM energy storage and fostering the sustainable growth of the energy storage industry within the State.

The ESS program was initially structured around three three-year deployment tranches, with interim capacity targets of 100 MW by 2025, 300 MW by 2028, and a cumulative 580 MW by 2030. Originally, the program capacity was split evenly between residential and C&I projects; in its Final Decision in Docket 24-08-05, PURA updated the split, with 150 MW allocated to residential projects and 430 MW to C&I projects. For systems enrolled prior to April 1, 2026 (referred to in this report as "Legacy" participants), the ESS program includes two primary incentives: upfront incentives that are contingent upon project performance during "Passive" dispatch periods, and performance-based incentives paid out based on project performance during "Active" events, as described in **Section 1.2**. Beginning with enrollments on April 1, 2026, participants are subject to a revised incentive structure ("Construct 5") adopted in PURA's Year 5 Decision, described in **Section 1.4**. In addition to Legacy vs. Construct 5, incentive levels are differentiated by sector (residential vs. C&I), system size, and other customer attributes, as discussed in the body of this report.

The updated sector and tranche-level capacity goals, following PURA's Year 4 Decision reallocation of 140 MW from residential to C&I, are shown in the **table below**. Note that, per direction from PURA, capacity associated with canceled projects within a given tranche is moved to subsequent tranches. Given that Construct 5 does not include a declining block incentive structure tied to the tranches, as was the case for the Legacy construct, the relevance of the tranches has diminished.

[1] Note that these goals were for all storage capacity, not limited to behind-the-meter or front-of-the-meter resources.

[2] https://www.dpuc.state.ct.us/2nddockcurr.nsf/8e6fc37a54110e3e852576190052b64d/6991ef77ba07bae185258752007994f7?OpenDocument

Table 1-1. ESS MW Goals by Tranche

Customer Class	Tranche 1	Tranche 2	Tranche 3	Tranche 4	Total
Residential	50 MW	50 MW	50 MW	0 MW	**150 MW**
C&I	50 MW	113.9 MW	126.1 MW	140 MW	**430 MW**
Total	**100 MW**	**163.9 MW**	**176.1 MW**	**140 MW**	**580 MW**

Source: *PURA Year 4 Final Decision*

The ESS program is guided by seven formal objectives adopted by PURA in its 2021 Storage Decision, summarized below:

1) Provide positive net present value to all ratepayers
2) Provide multiple types of benefits to the electric grid
3) Foster the sustained, orderly development of a state-based electric energy storage industry
4) Prioritize delivering increased resilience to lower income customers, customers most affected by outages, and critical facilities
5) Lower the barriers to entry, financial or otherwise, for electric storage deployment in Connecticut
6) Maximize the long-term environmental benefits of electric storage
7) Maximize the benefits to ratepayers derived from the wholesale capacity market

PURA conducts an annual review of the ESS program in Docket No. XX-08-05 each year. These proceedings assess program performance, review deployment progress, evaluate benefit-cost test results, and consider potential design adjustments.

1.2. Overview of Program Design

As noted above, PURA directed a significant change in the overall structure of the ESS program in its Year 5 Decision. At a high level, the changes, applicable to systems enrolling on or after April 1, 2026, include a significant reduction in upfront incentives and an increase in performance incentives. This change was intended to offer comparable total expected compensation to participating resources (on a discounted basis), while reducing ratepayer risk by allocating more program compensation to the performance of participating projects that produce benefits for ratepayers.

This analysis covers resources with an expected commercial operation date through the end of 2027. Given the April 1, 2026 transition from Legacy to Construct 5 and the development timeline of distributed storage, a significant majority of projects evaluated in this report will fall under the Legacy construct. Given this, both the Legacy and Construct 5 designs are described below, following an initial description of common program elements.

1.2.1. Legacy Construct

Under the Legacy structure, the Energy Storage Solutions program provides a combination of upfront and performance-based incentives. Upfront incentives are available to both residential and C&I participants, with rates differentiated by system size and customer characteristics.

The upfront incentives are denominated in dollars per installed kWh capacity. The residential and C&I upfront incentives, which are differentiated by sector (residential vs. C&I) and customer category, are presented in **Table 1-2**.

Table 1-2. Residential Upfront Incentive Levels (Legacy)

Incentive Step	Capacity Block	Standard ($/kWh)	Underserved ($/kWh)	Low-Income ($/kWh)
1	0-10 MW	$250	$450	$600
2	10-25 MW	$212.5	$450	$600
3	25-50 MW	$162.5	$450	$600
Grid Edge Adder: 50%[3]				

Source: *ESS Program Manual.*

Table 1-3. Commercial Upfront Incentive Levels (Legacy)

Tranche	Incentive Step	Capacity Block (Cumulative)	Small Commercial ($/kWh)	Medium Commercial ($/kWh)	Large Commercial ($/kWh)
1	n/a	0-50 MW	$200	$175	$100
2	n/a	50-163.9 MW	$200	$175	$100
3	1	163.9-213.9 MW	$182	$159.25	$91
3	2	213.9-238.9 MW	$164	$143.50	$82
3	3	238.9-290 MW	$146	$127.25	$73
Priority Customer Adder: 25%[4]					

Source: *ESS Program Manual and PURA Year 4 Final Decision*

Residential systems located in areas most impacted by outages (defined as the Grid Edge)[5] may receive a 50% adder on top of the applicable base upfront incentive. C&I customers that meet one of the following definitions ("priority customers") are eligible for a 25% adder:[6]

- **Grid Edge.** As defined above.
- **Small Business.** Defined as C&I customers with an annual peak demand of less than 200 kW.
- **Critical Facilities.** Facilities with critical functions, as defined by Gen. Stat. § 16-243y(a)(2).[7]

[3] See definition provided in Section 1.2
[4] See definition provided in Section 1.2
[5] The Grid Edge is defined as (1) the top ten percent of circuits with the highest number of outages per customer during major storms since July 1, 2012, and (2) the top ten percent of circuits with the longest outages due to major storms since July 1, 2012. Maps of circuits meeting these criteria are available on the ESS Contractor Resources page: https://energystoragect.com/contractor-resources/
[6] See full definitions in the ESS Program Manual: https://energystoragect.com/wp-content/uploads/2026/05/Energy-Storage-Solutions-Program-Manual-Revised-for-05-19-2026.pdf
[7] https://www.cga.ct.gov/2023/act/pa/pdf/2023PA-00157-R00HB-06853-PA.pdf

- **C&I Customers Replacing Fossil Fuel Generators.** Facilities replacing an existing, on-site fossil fuel generator with an energy storage system of a comparable size.

Residential upfront incentives are capped at 50% of the total installed cost of the BESS and are subject to an overall cap of $16,000 per residential unit. C&I upfront incentives are capped at 50% of the BESS' total installed cost. The upfront incentives are administered by the Green Bank.

Systems receiving an upfront incentive are obligated to discharge during Passive events, which occur during non-holiday weekdays in June, July, and August from 5 p.m. to 8 p.m. Systems that fail to meet certain criteria for Passive event performance may be subject to a clawback of the incentive, under the scoring methodology described below. Based on this methodology, systems that score less than 90% may be subject to a prorated incentive clawback. The Program Administrators may recommend to PURA that customers failing to meet the 90% threshold be relieved of the clawback provisions; the Program Administrators are required to submit any such recommendations to PURA by November 1 each year.

PURA instituted significant changes to the Passive dispatch scoring methodology in its Year 4 Final Decision. This updated methodology, which applies to all Legacy systems that received an upfront incentive, is included below. The scoring methodology used to evaluate Legacy Passive dispatch performance is shown in **Table 1-4**.

Table 1-4. Updated Passive Dispatch Scoring Methodology

Purpose	Formula Component
To ensure customers still receive credit for dispatching less than the full amount, and to relax the Program's uniform dispatch requirements.	**(Σ** (energy discharged during a Passive dispatch called event hour) ÷ (1/3 of a system's available energy at the start of the respective Passive dispatch event) [The allowable range for each Passive dispatch hour's score is 0 to 2, and scores that calculate as greater than 2 will be capped at 2.]
To fully incentivize peak reduction through active dispatch participation.	**+** (all active dispatch event hours called to replace a canceled Passive dispatch event in which a BESS discharged at least some portion of its available energy).
To ensure customers are not penalized for Passive events canceled by the Program Administrators.	**+** (all Passive dispatch hours canceled by the Program Administrators that were not replaced by an active dispatch event)
To prevent penalties for OEM-triggered storm events that are beyond the customer's control, allowing system usage during power outages.	**+** (all Passive dispatch event hours called, and all active dispatch event hours called to replace a Passive dispatch event, in which a battery could not perform because it was responding to an OEM-triggered severe storm event, provided the dispatch hour was not also canceled by the Program Administrators).**)**
To include all possible Passive dispatch hours, if no events were canceled.	÷ (total possible Passive dispatch hours in a given season)

Source: *PURA's Final Decision in Docket No. 24-08-05.*

Performance-based incentives are offered over a ten-year period and are paid based on system performance during active events in the summer and winter dispatch seasons. For the first five years, participating systems may earn $200 per average kW of delivered performance for the

summer season and $25 per average kW per winter season. In years six through ten, payments decline to $115/kW and $15/kW, respectively.

1.2.2. Construct 5

Beginning April 1, 2026, new ESS Program participants enroll in a new incentive structure, Construct 5, adopted in the Year 5 Decision, which replaces the upfront incentive and Passive dispatch structure with a smaller enrollment incentive paired with higher, ongoing Active dispatch performance payments. Systems already enrolled prior to April 1, 2026 ("Legacy" participants) continue under the upfront incentive and Passive dispatch structure described in **Section 1.2.1**.

As previously noted, incentives paid out at the time of project completion have been significantly reduced. Note that throughout this Report, unless otherwise specified, "upfront incentives" specifically refer to incentives paid out under the Legacy construct, while "enrollment incentives" refer to Construct 5. Construct 5 enrollment incentives are shown in **Table 1-5**, below. Customer segment definitions laid out above, including residential Grid Edge and C&I Priority Commercial, are the same for both Construct 5 and Legacy systems.

Table 1-5. Construct 5 Enrollment Incentives

Customer Segment	Enrollment Incentive ($ per kWh of installed capacity)
Residential (Non-Grid Edge)	$30/kWh
Grid Edge Residential	$130/kWh
Commercial Customers (non-Priority)	No enrollment incentive
Priority Commercial Customers	$10/kWh

Source: *ESS Program Manual*

Performance-based incentives for Construct 5 systems are offered over a ten-year period and are paid based on average kW-AC performance during active events in the summer and winter dispatch seasons. Unlike the Legacy structure, Construct 5 applies a single annual performance rate that varies by customer class rather than distinct summer and winter rates, as shown in **Table 1-6** below. Residential rates are held flat across the full ten-year term, while commercial rates step down between the opening period (years one through five) and the closing period (years six through ten). PURA indicated that it elected for higher performance rates for commercial systems in Years 1-5 because commercial customers may require stronger cash flows in the project's life, while residential customers may value the simplicity of a compensation rate fixed over the full 10 years. Because Construct 5 eliminates Passive Dispatch and the associated upfront incentive, participating systems are not subject to any pre-scheduled summer discharge window; instead, they respond only to Active Dispatch events.

Table 1-6. Construct 5 Performance Incentives

Customer Segment	Years 1-5	Years 6-10
Residential Standard	$300/kW	$300/kW
Residential Underserved	$450/kW	$450/kW
Residential Low-Income	$550/kW	$550/kW
Small/Medium Commercial	$325/kW	$175/kW
Large Commercial	$275/kW	$175/kW

Source: *ESS Program Manual*

PURA also expanded the winter dispatch season for Construct 5 participants to up to ten events per year, reflecting growing winter peak demand; the summer dispatch season is expected to remain at 30 to 60 events per season.

1.2.3. Elements Applicable to Legacy and Construct 5 Systems

The core approach to establishing performance for Active Dispatch compensation works the same way for both Legacy and Construct 5 customers: participants are paid based on their average kW-AC performance across all events called during each dispatch season, determined by measured performance rather than nameplate capacity. Events are called between 12:00 PM and 9:00 PM in both the summer and winter seasons, with the number of events, season dates, and event durations shown in **Table 1-7**. If a customer opts out of an event or is otherwise unable to discharge, that event is scored as 0 kW. If a customer charges during an event, resulting in a negative discharge, that negative number is also included when calculating seasonal performance. A "0" or a negative discharge lowers the seasonal average on which the incentive is based.

Table 1-7. Active Dispatch Parameters

Parameter	Summer	Winter
Season Dates	June 1 - September 30	November 1 - March 31
Number of Events	30-60	Legacy: 1-5 Construct 5: 1-10
Event Duration	1-3 hours	1-3 hours
Time Window	12:00 PM to 9:00 PM	12:00 PM to 9:00 PM

Source: *ESS Program Manual*[8]

Eligible projects must be located behind the meter, interconnected to the electric distribution system in Eversource or United Illuminating territory, and enrolled through a battery OEM app, a participating contractor, or third-party system owner (TPO). Both customer-owned and third-party-owned systems are permitted, provided they meet the program's minimum technical requirements, including warranty coverage, telemetry capabilities, and operational readiness. Some C&I systems with applications submitted before 2023 are allowed to participate in the

[8] https://energystoragect.com/wp-content/uploads/2026/05/Energy-Storage-Solutions-Program-Manual-Revised-for-05-19-2026.pdf

Forward Capacity Market, but, pursuant to PURA's Final Decision in Docket No. 22-08-05[9], systems installed starting in 2023 are prohibited from participating in the FCM.

1.3. Annual Report Requirements and Objectives

PURA's Final Decision[10] in Docket No. 17-12-03RE03 directed the Program Administrators to file annually a report summarizing the status of the program, providing key metrics, and providing any recommendations for program modifications. This report is provided in fulfillment of these requirements. The Program Administrators may also file separate Program Recommendations annually in Docket No. 24-08-05 Order 3.

1.4. Program Metrics Overview

Metrics included in this report are intended to enable PURA, the Program Administrators, and other interested stakeholders to evaluate the program's progress towards its goals, identify opportunities for improvement, and assess program cost effectiveness. This report provides three general categories of metrics:

1. **Program Tracking Metrics.** These metrics are tied primarily to enrollment data, assessing projects that have been completed and that are still under development, by type of project, electric distribution company (EDC), etc. Tracking metrics are presented in **Section 3** of this report.
2. **Program Evaluation Metrics.** These metrics evaluate the performance of completed systems, assessing their performance during Passive and Active events. Evaluation metrics are presented in **Section 4** of this report.
3. **BCA Metrics.** BCA metrics assess the cost effectiveness of the program from different test perspectives. BCA results are presented in **Section 5** of this report.

In general, CES prioritized calculating metrics in a way that is consistent with previous reports in order to enable meaningful comparisons and trend analysis. In several instances where it was determined that new or modified metrics could provide greater insights, these changes have been made. Where changes have been made, they have been noted in the relevant portion of the report.

2. Data Sources and Data Review

Data used to produce this evaluation is described below. Program enrollment and tracking data (i.e., data discussed in **Section 3**) is reported through June 30, 2026. Performance and operational data (discussed in **Section 4**), unless otherwise specified, is through March 31, 2026, the end of the Winter 2025/2026 active event season. Performance data prior to this, when included, is based on evaluations from previous annual reports.

9 https://www.dpuc.state.ct.us/dockcurr.nsf/8e6fc37a54110e3e852576190052b64d/5494c093c39b7f308525891f00571bba/$FILE/220805-122122.pdf

10 https://www.dpuc.state.ct.us/2nddockcurr.nsf/8e6fc37a54110e3e852576190052b64d/6991ef77ba07bae185258752007994f7?OpenDocument

2.1. Data from Program Administrators

The following data was provided by the Program Administrators:

- **Program Enrollment Data.** This dataset, from the Green Bank's tracking database, provides details on systems participating or intending to participate in the ESS Program. Fields include detailed system characteristics, customer information, cost data, and dates of relevant milestones. The data is derived from the same Green Bank database used for most of the metrics included in the Energy Storage Solutions Performance Report.[11]
- **Program Administration Costs.** This data is reported separately by each Program Administrator. For benefit cost analysis (BCA), projections of future program administration costs were also provided.
- **Outage Data.** Eversource and UI provided data on outages that affected ESS participants, detailing each outage instance and duration by affected customer.
- **Outage Protection Data**. Some BESS equipment includes functionality that automatically overrides participation in incentive programs (like ESS) when there is a weather event that could lead to outages. This functionality allows systems to maintain a higher state of charge in anticipation of possible outages, so that they can provide backup power if the outages arise. For the evaluated period, data was made available for Enphase, Franklin, and Generac systems, but no other OEMs provided this data. Given that this data is not available for all participating OEMs and that there are differences in how values are reported, metrics specifically related to these datasets are not included in this report.
- **Performance Incentive Data.** Eversource and UI provided data summarizing payments made to systems for their active event performance during Summer 2025 and Winter 2025/2026.
- **Active Event Data.** Eversource and UI provided a list of active events that occurred during Summer 2025 and Winter 2025-2026.[12]

2.2. Telemetry Data

Telemetry data provides information on the performance of resources, including fields such as project ID and ESS project ID, charging/discharging energy, battery state of charge and/or stored energy, and solar PV production if available. The Program Administrators made telemetry available for the period of January 2024 through June 2026. For the previous Annual Report, most telemetry data evaluated by CES came directly from distributed energy resource management system (DERMS) providers with minimal processing, or, in some instances, directly from original equipment manufacturers (OEMs).

For this Report, all telemetry data evaluated by CES was provided by the Green Bank through new data-sharing agreements with the DERMS providers. Many of the data quality considerations and processing steps identified in the previous year's report are addressed by the Green Bank before

[11] https://energystoragect.com/ess-performance-report/. Slight variations in the fields used to calculate metrics and data entry and edits make replicating the exact figures in this report from the Performance Report challenging.

[12] This data is also available here: https://energystoragect.com/contractor-resources/; see "ESS Summer 20XX / Winter 20XX-20XX Events List" documents

the data was provided to CES. This has noticeably improved the quality of the data evaluated by CES.

2.3. Data Review

2.3.1. Program Enrollment Data

There were relatively few issues identified with the enrollment data. Most challenges related to ensuring a consistent interpretation of edge cases (e.g., sites where additional battery capacity was added) and to the completeness of the data set. On the latter question, based on discussions with the Green Bank, most data completeness questions are tied to projects that were transferred from ConnectedSolutions to ESS and to Active Only or Construct 5 projects where customers used a "self-enrollment" approach, primarily Tesla customers. In both of these cases, the Green Bank did not have access to full ESS enrollment details, leading to missing fields. In some cases, the Program Administrators were able to layer additional fields in from other data sources (e.g., PowerClerk); while drawing information for a given field from different data sources may lead to inconsistency in the data, having some data is still more helpful than none. There were also cases in which key fields for some projects are unavailable. For example, installed costs are available for few of the Active Only projects. For tables drawing on enrollment data (primarily within **Section 3**), records that were missing relevant data were eliminated from the table. As a result, totals (e.g., total project count) will vary across different tables.

2.3.2. Telemetry Data

In general, the quality of the telemetry data has improved substantially relative to data reviewed for the previous annual report. CES implemented a series of quality control checks that evaluated the following (as well as other checks not listed):

- Overall volume of missing values
- For stored energy field, instances of missing values or 0 kWh during the interval at the beginning of an event
- Sign reversal (i.e., energy discharge recorded as a positive value instead of a negative value)
- Comparison of maximum kW and stored kWh values in the telemetry data against nameplate capacity values in the enrollment data
- Comparison of kW charge/discharge, kWh charge/discharge, and stored energy fields in the telemetry data, looking for consistency across these three fields

The nature of the data quality issues varied significantly. Some were intermittent and had straightforward explanations (e.g., missing data for isolated periods, likely due to connectivity issues). Some issues were harder to explain, such as isolated periods in which kW charge/discharge, kWh charge/discharge, and stored energy fields did not move in tandem. Other issues were more structural, including instances in which telemetry data regularly indicated kW discharged or stored kWh that exceeded nameplate values.

CES engaged the Program Administrators to resolve as many of the identified issues as possible. CES is aware that the Program Administrators regularly work with DERMS providers and OEMs to address data quality issues; many of the issues identified by CES had already been identified by the Program Administrators.

Of the issues remaining in the evaluated telemetry data, CES determined that it was not feasible to reliably resolve the data quality issues; instead, CES excluded data that triggered quality control flags. This resulted in the removal of approximately 4% of telemetry data occurring during days with an Active or Passive event from the evaluated data set.

2.4. Findings and Recommendations

CES has identified the following findings and recommendations related to data collection, sharing, and processing. As indicated above, CES noted improvements in data quality and collection process relative to last year.

Table 2-1. Data Availability and QC Findings and Recommendations

Finding	Recommendation
CES identified instances in which projects consistently reported max kW discharged or stored kWh in the telemetry data that exceed nameplate values. CES is aware that this is a question that the Program Administrators have raised with DERMS providers and OEMs.	The Program Administrators should continue to engage with DERMS providers and OEMs to resolve this issue. To the extent that a satisfactory explanation or adjustment to the data cannot be made by the DERMS providers and/or OEMs, the Program Administrators should consider scaling telemetry values (particularly the kW discharged field, given that it determines performance payments) to ensure that telemetry values match nameplate values.
CES is aware that the Program Administrators often identify data quality issues before OEMs or DERMS providers.	The Program Administrators should continue to push DERMS providers to implement more rigorous and proactive quality control. While OEMs also play a critical role in maintaining high-quality data, the DERMS providers are best positioned to provide ongoing, proactive quality control.

Source: *CES analysis*

3. Program Tracking Metrics

Program tracking metrics, related findings, and recommendations are presented in this section.

3.1. Program Tracking Categorization

Project categories, which guide the interpretation of the metrics in this section, are provided below.

3.1.1. Project Stage Categories

Metrics in this section are filtered by, and, in many cases, differentiated by project stage. A summary of the project stage categories is presented below.

Table 3-1. Project Stage Categories

Program Tracking Status	Definition
Approved	Project has been reviewed by the Green Bank and all submitted project information and documentation are correct or has been previously sent back for additional information/edits.
Cancelled	Project has been cancelled and removed from the submitted, approved, or completed stage, by the contractor and/or Green Bank. Unless otherwise specified, these projects have been excluded from the metrics in this section.
Completed	Project has been approved, installed, energized, and has either been verified in the DERMS platform, or is in the process of doing so.
Pipeline	Project application has been initiated, but not yet completed. Unless otherwise specified, these projects have been excluded from the metrics in this section.
Submitted	Project has submitted all required documentation but is not yet approved.

Note: The underlying data also includes an "Inspection" stage. For the purposes of program tracking metrics, CES has included these projects in the "Approved" stage.

Source: *Connecticut Green Bank*

3.1.2. Project Unit Definitions

Program tracking metrics provided in this section are based on definitions that align with the structure of the Green Bank database from which the underlying data is derived.

- **Application.** An application is associated with a single submission for an upfront incentive and is associated with a specific "system".
- **System or Project.** A system represents all ESS-enrolled battery storage hardware at a single customer site (generally, behind a single customer meter). In this report, the term "project" also refers to a "system".
- **Battery Unit.** The Green Bank collects information about individual pieces of hardware associated with a single "system." This may include multiple integrated BESS, separate storage banks and inverters, or other combinations of hardware. Multiple battery units may be associated with a single "system".
- **Participant.** A participant is associated with a specific applicant (or, after the project is completed, operational project). A Participant has a one-to-one relationship with an "application" and "system."

3.1.3. Residential Categories

Residential systems are categorized within one of the three segments, described in **Table 3-2** below.

Table 3-2. Residential Project Categories

Residential Segment	Definition
Low-Income	Includes projects at the site of households with incomes below 60% of state median income as well as multifamily affordable housing, based on PURA's Final Decision in Docket No. 23-08-05[13].
Underserved	Projects located within distressed municipalities, as defined by the Connecticut Department of Economic Community Development (DECD). [14]
Standard	All projects that do not qualify as Low-Income or Underserved.

Source: *ESS Program Manual.* [15]

Some projects qualify as both Low-Income and Underserved; these projects receive the Low-Income incentive and are categorized as Low-Income in this report. This is the same approach to determining the appropriate incentive level for a project. In its Final Decision in Docket No. 17-12-03-RE03,[16] PURA directed the Program Administrators to seek a goal of 40% of residential projects qualifying as Low-Income or Underserved.

3.1.4. C&I Categories

Commercial customers fall within one of three categories based on peak demand, defined in **Table 3-3**. Annual peak demand is defined as the highest peak demand billed for the 12 months prior to application to the ESS program. Applicants may choose to enroll projects with a rated power capacity that exceeds their annual peak demand, with a limit of the greater of 150% of the customer's annual peak demand or 2 MW. In these instances, their upfront incentive or enrollment incentive is prorated.[17]

[13] https://www.dpuc.state.ct.us/dockcurr.nsf/8e6fc37a54110e3e852576190052b64d/d7b4cb81bf3765ea85258a7600551890/$FILE/230805-112923.pdf

[14] A more complete description of eligibility criteria for being identified as a Distressed Municipality, as well as a current list of Distressed Municipalities, is available from the Department of Economic and Community Development, here: https://portal.ct.gov/decd/content/about_decd/research-and-publications/02_review_publications/distressed-municipalities

[15] https://energystoragect.com/wp-content/uploads/2025/01/ESS-Program-Manual-01172025-Clean-FINAL.pdf

[16] https://www.dpuc.state.ct.us/2nddockcurr.nsf/8e6fc37a54110e3e852576190052b64d/6991ef77ba07bae185258752007994f7?OpenDocument

[17] An illustration of how this prorating works is available in the incentive calculators available here: https://energystoragect.com/contractor-resources/

Table 3-3. Commercial Project Categories

C&I Segment	Annual Peak Demand
Small Commercial	Below 200 kW
Medium Commercial	200 kW-500 kW
Large Commercial	Greater than 500 kW

Source: *ESS Program Manual.*

As discussed in Section 1, Priority commercial customers are also eligible for higher upfront incentives (Legacy) and Priority commercial customers are eligible for an enrollment incentive under Construct 5 (non-Priority commercial customers are not eligible for any enrollment incentive under Construct 5).

3.1.5. Hybrid Project

This report includes a project that serves a building comprising both multi-family affordable housing and non-residential space, referred to as a hybrid project. The project was approved as a single large C&I application, but is designed to benefit both one large C&I participant and 161 residential low-income participants. Based on PURA's Year 3 Final Decision,[18] which updated the definition of low-income to include affordable multi-family housing, the project has been categorized as low-income.

The Connecticut Green Bank determined that the system's use would be allocated 48% to residential low-income and 52% to large commercial, based on the share of site load serving apartments versus shared commercial functions such as community rooms and a charter school. This same 48% and 52% split is applied in **Section 3.2** of this report to allocate system capacity, costs, and incentives between the two program categories. Where applicable, tables in this report indicate whether the hybrid project has been treated as 161 residential projects and 1 commercial project or consolidated as a single commercial project. As the project is under construction, it is not included in any of the telemetry data evaluated in **Section 4** of this report.

As discussed in the Key Findings and Recommendations section of this report, achieving the target of 40% residential Low-Income and Underserved participation will likely require additional multifamily affordable housing projects to enroll, though no additional multifamily affordable housing projects have enrolled since this project, which enrolled in 2023.

3.2. Program Tracking Metrics

The metrics provided below include projects with an application date before June 30, 2026. Following an email from Eversource to approximately 900 residential ConnectedSolutions customers, approximately 328 residential projects were transferred from ConnectedSolutions to the ESS program, receiving the applicable Construct 5 performance incentives. Unless otherwise noted, these projects are included in metrics included in this report. Remaining residential ConnectedSolutions customers will have until December 2027 to transfer into ESS; at that point, any customers that have not decided to transfer will be unenrolled from ConnectedSolutions.

18 https://www.dpuc.state.ct.us/dockcurr.nsf/8e6fc37a54110e3e852576190052b64d/d7b4cb81bf3765ea85258a7600551890?OpenDocument

Table 3-4 provides ESS participants by project stage, utility, and project category. The number of projects in the submitted status is attributable to the relatively short period of time required for the Green Bank to review projects and, if eligibility criteria are met, move them to the approved stage. Relative to the same period last year, the total number of completed projects has approximately tripled. This includes an increase from 458 to 1388 completed residential projects and from 4 to 10 completed commercial projects. The number of approved projects is similar to the same time last year. These values demonstrate that commercial projects continue to progress through the pipeline slowly, while residential projects move from submitted, to approved, to completed relatively quickly, as also demonstrated in Table 3-8. The pace of commercial project completion and the overall expected contribution of commercial projects to ESS goals suggests that the Program Administrators will struggle to meet ESS targets.

Currently, UI's share of total participants, including submitted, approved, and completed (19%) is in line with its projected share (20%).

Table 3-4. ESS Participants (Number and Percentage of Total)

Utility	Customer Type	Project Status as of June 30, 2026			
		Submitted	Approved	Completed	Total
Eversource	Residential Standard	23 (1%)	139 (7%)	1055 (55%)	**1217 (63%)**
	Residential Underserved	9 (<1%)	33 (2%)	133 (7%)	**175 (9%)**
	Residential Low-Income	0 (<1%)	32 (2%)	69 (4%)	**101 (5%)**
	Residential Subtotal	***32 (2%)***	***204 (11%)***	***1257 (65%)***	***1493 (78%)***
	Small C&I	0 (<1%)	8 (<1%)	4 (<1%)	**12 (<1%)**
	Medium C&I	0 (<1%)	17 (<1%)	0 (<1%)	**17 (<1%)**
	Large C&I	0 (<1%)	28 (1%)	3 (<1%)	**31 (2%)**
	C&I Subtotal	***0 (<1%)***	***53 (3%)***	***7 (<1%)***	***60 (3%)***
	Eversource Subtotal	**32 (2%)**	**257 (13%)**	**1264 (66%)**	**1553 (81%)**
United Illuminating	Residential Standard	5 (<1%)	19 (<1%)	97 (5%)	**121 (6%)**
	Residential Underserved	1 (<1%)	27 (1%)	34 (2%)	**62 (3%)**
	Residential Low-Income	0 (<1%)	175 (9%)	0 (<1%)	**175 (9%)**
	Residential Subtotal	***6 (<1%)***	***221 (11%)***	***131 (7%)***	***358 (19%)***
	Small C&I	0 (<1%)	2 (<1%)	0 (<1%)	**2 (<1%)**
	Medium C&I	0 (<1%)	2 (<1%)	3 (<1%)	**5 (<1%)**
	Large C&I	0 (<1%)	5 (<1%)	0 (<1%)	**5 (<1%)**
	C&I Subtotal	***0 (<1%)***	***9 (<1%)***	***3 (<1%)***	***12 (<1%)***
	UI Subtotal	**6 (<1%)**	**230 (12%)**	**134 (7%)**	**370 (19%)**
Total Number of Residential Participants		**38 (2%)**	**425 (22%)**	**1388 (72%)**	**1851 (96%)**
Total Number of C&I Participants		**0 (<1%)**	**62 (3%)**	**10 (<1%)**	**72 (4%)**
Total Number of Participants		**38 (2%)**	**487 (25%)**	**1398 (73%)**	**1923 (100%)**

Note: The "Total" column reflects the combined number of submitted, approved, and completed projects, excluding any cancelled and pipeline projects as defined in Section 3.1.1. All percentages are based on the total number of participants across these categories. The hybrid project, detailed in Section 3.1.5, has been counted as 161 participants under United Illuminating's Residential Low-Income and 1 participant under United Illuminating's Large C&I, in accordance with program guidance. All other applications are counted as a single participant.

Source: *CES analysis of Connecticut Green Bank program tracking data through June 30, 2026*

Table 3-5 shows the share of residential projects by customer type for approved and completed systems. The program is short of the established objective of 40% Underserved and Low-Income projects[19] on both a project count (28%) and MW (19%) basis. The total number of Underserved and Low-Income participants (501) is largely attributable to the single, large, affordable multifamily housing project which represents 161 participants. As noted in last year's report, the program will struggle to meet its Low-Income and Underserved target without additional affordable multifamily projects, though there are no such projects in the queue. This risk is underscored by the numbers: the Low-Income and Underserved participant rate (by count) fell from 38% last year to 28% this year.

Table 3-5. Share of Low-Income & Underserved Residential Participants

Upfront Incentive Received	Percentage by Expected Installed Capacity (MW)	Percentage by Number of Participants
Standard	81%	72%
Underserved	12%	13%
Low-Income	7%	15%
Underserved or Low-Income	**19%**	**28%**

Note: Table includes only approved and completed residential systems. Percentages may not total 100% due to rounding. The hybrid project's capacity, described in Section 3.1.5, has been proportionally allocated to 48% under Residential Low-Income, in accordance with guidance from the Green Bank. This project accounts for 161 participants under the Residential Low-Income category.

Source: *CES analysis of Connecticut Green Bank program tracking data through June 30, 2026.*

As described in **Section 1.2**, certain C&I projects with submission dates before January 1, 2023, were eligible to participate in the FCM. **Table 3-6** identifies the portion of commercial projects that are qualified for the FCM but are not expected to bid, those that are expected to bid, and those that, per the ESS Program rules, were not eligible to monetize their capacity revenue. Changes from the previous period are driven by changes in total commercial participation, including project cancellations. As noted below the table, per guidance from the Green Bank, projects that are eligible to participate in the FCM but have not affirmatively indicated that they will not participate (i.e., the relevant field in their application has been left blank) are assumed to be intending to participate. Therefore, CES anticipates that the actual number of projects participating in the FCM will be lower than the numbers indicated below. In practice, confirming FCM participation status before projects come online would require direct contact with individual participants. The Program Manual requires that projects eligible to participate in the FCM report to the Program Administrators on an annual basis if they have participated in the FCM.

[19] As established in PURA's Final Decision in Docket No. 17-12-03-RE03

Table 3-6. Indication of Participation in the ISO-NE FCM for C&I Participants

Upfront Incentive Received	Percentage by Expected Installed Capacity (MW)	Percentage by Number of Participants
Qualified & Expected to Bid	28%	19%
Qualified & Not Bidding	16%	13%
Not Qualified	56%	67%

Note: This table includes all approved and completed C&I projects, whether or not they qualified to retain capacity rights. "Not Qualified" capacity and participant figures include systems that either failed to meet the eligibility criteria prior to 2023 or were enrolled in 2023 or later. The hybrid project, which does not qualify to retain its capacity rights and is detailed further in Section 3.1.5, has been allocated with 52% of its capacity classified under C&I, as directed by the Green Bank. It accounts for one participant under the C&I category.

Source: CES analysis of Connecticut Green Bank program tracking data through June 30, 2026.

The table below shows counts of applications by project stage, including pipeline applications (application has been submitted but not completed) and cancelled applications. Reasons for cancellations include projects failing to meet eligibility criteria and project sponsors choosing to no longer pursue the project. Residential cancellation rates (as measured by count of canceled applications divided by total count of all statuses included in the table) remain relatively steady. Commercial cancellation rates have increased considerably, however: of the 151 commercial applications (including approved or completed) in the table, 77 (51%) are cancellations; this is up from 25% in last year's report. This is particularly concerning given that the number of approved or completed commercial projects is unchanged since last year, and the number of pipeline or submitted but not completed commercial projects is down from 11 to 2.

Table 3-7. Project Approval Rates

Utility	Customer Type	Project Status as of June 30, 2026			
		Pipeline (Applications)	Submitted (Applications)	Approved or Complete (Applications)	Cancelled (Applications)
Eversource	Residential Standard	8% (130/1639)	1% (23/1639)	73% (1194/1639)	18% (292/1639)
	Residential Underserved	10% (23/230)	4% (9/230)	72% (166/230)	14% (32/230)
	Residential Low-Income	3% (3/115)	0% (0/115)	88% (101/115)	10% (11/115)
	Residential Overall	***8% (156/1984)***	***2% (32/1984)***	***74% (1461/1984)***	***17% (335/1984)***
	Small C&I	5% (1/21)	0% (0/21)	57% (12/21)	38% (8/21)
	Medium C&I	0% (0/43)	0% (0/43)	40% (17/43)	60% (26/43)
	Large C&I	0% (0/60)	0% (0/60)	52% (31/60)	48% (29/60)
	C&I Overall	***1% (1/124)***	***0% (0/124)***	***48% (60/124)***	***51% (63/124)***
	Eversource Overall	**7% (157/2108)**	**2% (32/2108)**	**72% (1521/2108)**	**19% (398/2108)**
United Illuminating	Residential Standard	6% (11/172)	3% (5/172)	67% (116/172)	23% (40/172)
	Residential Underserved	7% (6/92)	1% (1/92)	66% (61/92)	26% (24/92)
	Residential Low-Income	0% (0/178)	0% (0/178)	98% (175/178)	2% (3/178)
	Residential Overall	***4% (17/442)***	***1% (6/442)***	***80% (352/442)***	***15% (67/442)***
	Small C&I	0% (0/6)	0% (0/6)	33% (2/6)	67% (4/6)
	Medium C&I	8% (1/12)	0% (0/12)	42% (5/12)	50% (6/12)
	Large C&I	0% (0/9)	0% (0/9)	56% (5/9)	44% (4/9)
	C&I Overall	***4% (1/27)***	***0% (0/27)***	***44% (12/27)***	***52% (14/27)***
	UI Overall	**4% (18/469)**	**1% (6/469)**	**78% (364/469)**	**17% (81/469)**
Percentage of Residential Applications		**7% (173/2426)**	**2% (38/2426)**	**75% (1813/2426)**	**17% (402/2426)**
Percentage of C&I Applications		**1% (2/151)**	**0% (0/151)**	**48% (72/151)**	**51% (77/151)**
Percentage of Total Applications		**7% (175/2577)**	**1% (38/2577)**	**73% (1885/2577)**	**19% (479/2577)**

Note: Note that "Canceled" applications does not include projects labeled as "withdrawn," as withdrawn applications were never officially submitted and/or may have never received a reservation of funds letter. Percentages presented above are based on the number of applications, not the number of participants associated with each application. As such, the hybrid project, detailed in Section 3.1.5, is considered a single Large C&I application for the purposes of this table. Note that withdrawn applications are excluded from the table above.

Source: *CES analysis of Connecticut Green Bank program tracking data through June 30, 2026.*

Table 3-8 lends insight into the time required for upfront incentive applications to be reviewed and for projects to achieve commercial operation (complete status). Results are shown by the year in which they were submitted. Note that, for applications submitted through 2022, some of the processing times have changed somewhat, due to project cancellations and other changes to project statuses – an issue with the calculation of processing times for projects with missing data that affected the previous year's report has also been corrected. Notably, the time to approve residential applications has consistently fallen over time. Days to approve C&I applications have generally decreased over time; time to approve C&I applications is influenced by the need for the Green Bank to seek approval from its Board of Directors for upfront incentives greater than $500,000. The days for residential projects to move to completed status have decreased over time, demonstrating increasing maturity in the residential storage space. There is insufficient data for commercial projects to draw conclusions about changes in the pace of

development; the available data highlights, however, that commercial projects take a long time to move from application approval to project completion.

Table 3-8. Average Days to Approve and Complete Project Application

Customer Type	Application Submittal Year	Average Days to Approve Application	Average Days to Completion
Residential	2022	58	546
	2023	65	292
	2024	56	209
	2025	24	160
	2026	16	87
Residential Overall		***42***	***247***
C&I	2022	246	732
	2023	88	N/A
	2024	42	480
	2025	61	243
	2026	22	N/A
C&I Overall		***93***	***590***
Total Program Average Days		**38**	**45**

Note: All figures presented reflect simple averages across applications and are not weighted by system size or number of participants. Accordingly, the hybrid project, discussed in Section 3.1.5, is treated as a single C&I application in this table. Estimates for average days to application approval and project completion may differ from previous reports due to changes in program enrollment (e.g., unenrollments). The application review process may involve multiple rounds of communication with project developers to ensure completeness and accuracy, which can extend approval timelines.

Source: *CES analysis of Connecticut Green Bank program tracking data through June 30, 2026.*

Table 3-9 provides metrics related to the share of systems and participants that are paired with on-site PV. The vast majority of residential projects continue to be paired with PV. However, Large C&I projects have a significantly lower PV pairing rate, which reduces the solar pairing rate when calculated using battery energy (kWh). Most BTM solar plus storage systems will be able to charge either from the grid or from solar depending on their tariff structure; however, in instances in which the solar and storage share an inverter, energy storage discharge may be limited during hours of solar production based on the rating of the inverter. While Passive and Active events occur later in the day, after the peak solar production hours, there still may be limited instances in which energy storage discharge during ESS events is inverter-limited (i.e., storage cannot discharge at rated or desired capacity because the inverter does not have the capacity for both solar output and desired storage discharge).

Table 3-9. Share of Energy Storage Paired with PV

Customer Type	By Number of Systems	By Number of Participants	By System's kWh	By Allocated kWh
Residential Standard	89%	89%	89%	89%
Residential Underserved	91%	91%	90%	90%
Residential Low-Income	99%	100%	99%	100%
Residential Average	***90%***	***91%***	***89%***	***90%***
Small C&I	57%	57%	29%	29%
Medium C&I	55%	55%	35%	35%
Large C&I	36%	36%	26%	26%
C&I Average	***46%***	***46%***	***29%***	***28%***
Overall Average	**88%**	**89%**	**34%**	**34%**

Note: The analysis of energy storage systems paired with solar PV includes only projects in the "Approved" or "Completed" stages. Due to rounding, table values may not sum to 100%. The hybrid project, which includes a fuel cell and is discussed in Section 3.1.5, is counted as a single Large C&I application in the "by system" columns and as 161 participants under Residential Low-Income and 1 participant under Large C&I in the "by participants" column, and is fractionalized for the "allocated kWh" column with 48% of its energy capacity attributed to Residential Low-Income and 52% to Large C&I, based on guidance from the Green Bank.

Source: *CES analysis of Connecticut Green Bank program tracking data through June 30, 2026.*

Table 3-10 shows total kW of project capacity by project status, utility, and customer segment. This table highlights how, on a kW basis, C&I projects dominate expected future kW (as reflected in projects with an approved status), while residential projects continue to dominate the completed kW operating in the program. The total kW has decreased by approximately 1 MW since the previous report; this is primarily a result of a reduction in approved C&I capacity of 13 MW resulting primarily from cancelled projects (as opposed to projects moving from approved to completed). For residential, the total values represent 15% of the program's target of 150 MW; for commercial projects, it is 31% of 430 MW. Comparing these numbers is likely misleading, however, given that commercial projects have seen significantly higher levels of attrition.

Table 3-10. Total Allocated Power Capacity (kW) by Project Status

Utility	Customer Type	Project Status as of June 30, 2026			
		Submitted (kW)	Approved (kW)	Completed (kW)	Total (kW)
Eversource	Residential Standard	279	2,088	13,875	**16,242**
	Residential Underserved	88	389	1,636	**2,113**
	Residential Low-Income	0	259	651	**910**
	Residential Subtotal	***367***	***2,736***	***16,161***	***19,264***
	Small C&I	0	6,088	625	**6,713**
	Medium C&I	0	27,859	0	**27,859**
	Large C&I	0	86,835	507	**87,342**
	C&I Subtotal	***0***	***120,782***	***1,132***	***121,914***
	Eversource Subtotal	**367**	**123,518**	**17,293**	**141,178**
United Illuminating	Residential Standard	32	295	1,079	**1,406**
	Residential Underserved	10	236	323	**569**
	Residential Low-Income	0	576	0	**576**
	Residential Subtotal	***42***	***1,107***	***1,402***	***2,552***
	Small C&I	0	764	0	**764**
	Medium C&I	0	2,268	155	**2,423**
	Large C&I	0	8,509	0	**8,509**
	C&I Subtotal	***0***	***11,541***	***155***	***11,696***
	UI Subtotal	**42**	**12,648**	**1,557**	**14,248**
Total Power Capacity: Residential (kW)		**409**	**3,843**	**17,564**	**21,816**
Total Power Capacity: C&I (kW)		**0**	**132,323**	**1,287**	**133,610**
Total Power Capacity (kW)		**409**	**136,166**	**18,850**	**155,426**

Note: The "Total" column represents the sum of submitted, approved, and completed projects, excluding any cancelled and pipeline projects, as defined in Section 3.1.1. The hybrid project's capacity, further detailed in Section 3.1.5, has been fractionalized per guidance from the Green Bank, with 48% to United Illuminating's Residential Low-Income and 52% to United Illuminating's Large C&I.

Source: *CES analysis of Connecticut Green Bank program tracking data through June 30, 2026.*

Table 3-11 provides similarly structured data, calculated for kWh of storage capacity instead of kW. This table illustrates many of the same trends as the previous table, particularly, that C&I projects dominate the program's approved kWh.

Table 3-11. Total Allocated Energy Capacity (kWh) by Project Status

Utility	Customer Type	Project Status as of June 30, 2026			
		Submitted (kWh)	Approved (kWh)	Completed (kWh)	Total (kWh)
Eversource	Residential Standard	508	3,604	28,321	**32,433**
	Residential Underserved	113	802	3,253	**4,167**
	Residential Low-Income	0	612	1,415	**2,027**
	Residential Subtotal	***620***	***5,018***	***32,989***	***38,627***
	Small C&I	0	20,350	3,060	**23,410**
	Medium C&I	0	70,994	0	**70,994**
	Large C&I	0	201,176	1,156	**202,332**
	C&I Subtotal	***0***	***292,520***	***4,216***	***296,736***
	Eversource Subtotal	**620**	**297,538**	**37,205**	**335,364**
United Illuminating	Residential Standard	68	515	1,970	**2,553**
	Residential Underserved	15	521	713	**1,249**
	Residential Low-Income	0	2,102	0	**2,102**
	Residential Subtotal	***83***	***3,138***	***2,683***	***5,904***
	Small C&I	0	1,732	0	**1,732**
	Medium C&I	0	5,718	344	**6,062**
	Large C&I	0	27,658	0	**27,658**
	C&I Subtotal	***0***	***35,108***	***344***	***35,452***
	UI Subtotal	**83**	**38,246**	**3,027**	**41,356**
Total Energy Capacity: Residential (kWh)		**703**	**8,156**	**35,673**	**44,531**
Total Energy Capacity: C&I (kWh)		**0**	**327,628**	**4,560**	**332,188**
Total Energy Capacity (kWh)		**703**	**335,784**	**40,233**	**376,720**

Note: The "Total" column represents the sum of submitted, approved, and completed projects, excluding any cancelled and pipeline projects, as defined in Section 3.1.1. The hybrid project's capacity, further detailed in Section 3.1.5, has been fractionalized per guidance from the Green Bank, with 48% to United Illuminating's Residential Low-Income and 52% to United Illuminating's Large C&I.

Source: *CES analysis of Connecticut Green Bank program tracking data through June 30, 2026.*

Table 3-12 highlights average system size (in kW and kWh) per participant for approved and completed projects. Residential project sizes have remained relatively stable, with a modest increase in average kW from 10 to 12, with project duration remaining stable. The average kWh for residential standard projects in Eversource territory is significantly larger than in UI territory, likely a reflection of the housing stock served by the two utilities. The UI low-income average duration is an outlier, driven by the 4-hour durations of the multifamily project allocated to these customers.

Relative to last year, commercial systems have seen a small decrease in size (2,015 kW to 1,856 kW) and duration (2.6 hours to 2.5 hours). Commercial systems have a longer average duration than residential systems; this is likely driven by the equipment available to the two different segments (i.e., more opportunity to customized duration for commercial systems than residential) as well as the value proposition (e.g., C&I customers may seek longer duration to manage demand charges and more aggressively engage in retail rate arbitrage).

Table 3-12. Average Project Size

Utility	Customer Type	Average System Size		
		Power Capacity (kW/participant)	Energy Capacity (kWh/participant)	Weighted Average Nominal Duration (hrs)
Eversource	Residential Standard	13	27	2.0
	Residential Underserved	12	24	2.0
	Residential Low-Income	9	20	2.2
	Residential Average	***13***	***26***	***2.0***
	Small C&I	559	1,951	3.5
	Medium C&I	13	27	2.0
	Large C&I	12	24	2.0
	C&I Average	9	20	2.2
	Eversource Average	***13***	***26***	***2.0***
United Illuminating	Residential Standard	559	1,951	3.5
	Residential Underserved	1,639	4,176	3
	Residential Low-Income	2,817	6,527	2.3
	Residential Average	***2,032***	***4,946***	***2.4***
	Small C&I	**93**	**220**	**2.4**
	Medium C&I	12	21	2
	Large C&I	9	20	2.2
	C&I Average	3	12	3.6
	UI Average	***7***	***17***	***2.3***
Average System Size for Residential Systems		**12**	**24**	**2.0**
Average System Size for C&I Systems		**1,856**	**4,614**	**2.5**
Average System Size		**82**	**199**	**2.4**

Note: The average system size analysis includes only projects in the "approved" or "completed" stages. The hybrid project's capacity, further detailed in Section 3.1.5, has been fractionalized per guidance from the Green Bank, with 48% to United Illuminating's Residential Low-Income and 52% to United Illuminating's Large C&I. For reporting purposes, it accounts for 161 participants under United Illuminating's Residential Low-Income and 1 participant under United Illuminating's Large C&I.

Source: *CES analysis of Connecticut Green Bank program tracking data through June 30, 2026.*

Table 3-13 shows the number of systems and battery units by manufacturer. Tesla replaced FranklinWH as the manufacturer with the most participating residential systems, followed by FranklinWH which also saw significant growth compared to last year. On the C&I side, Tesla continues to have the largest number of systems. Note that canceled applications have led to some previously-listed manufacturers not being included in this year's table.

Table 3-13. Number of Systems and Batteries by Manufacturer

Customer Type	Make	Number of Systems	Number of Battery Units
Residential	Tesla	616	2250
	FranklinWH	475	1869
	Enphase Energy	194	958
	Generac Power Systems	191	387
	SunPower	93	209
	Fortress Power LLC	26	105
	SolarEdge Technologies Ltd.	19	64
	HomeGrid	11	21
	EndurEnergy Systems, Inc. ESP	10	67
	PointGuard Energy	3	14
	Pylon Technologies	3	16
	StackRack Battery Systems	3	11
	Cadenza Innovation	2	6
	LG Chem	2	4
	Sigenergy	2	11
	EG4 Electronics	1	4
	Panasonic Corporation	1	4
C&I	Tesla	33	45
	ELM Fieldsight LLC	15	73
	Narada Power	11	22
	Yotta Energy	5	555
	Lithtech	2	9
	Socomec	2	2
	American Energy Storage Innovations (AESI)	1	3
	Cadenza Innovation	1	2
	Cornex	1	2
	Generac Power Systems	1	2
	PurePoint Energy LLC	1	2
	Waldron Engineering & Construction, Inc.	1	2

Note: Counts of "system" and "battery unit" reflect only those projects in the "approved" or "completed" stages. As detailed in Section 3.1.5, the hybrid project is treated as a single C&I application for the purposes of this table.

Source: *CES analysis of Connecticut Green Bank program tracking data through June 30, 2026.*

Table 3-14 provides data on applications by contractor. Most contractors serve only residential or only C&I customers. Earthlight Technologies has the largest share of residential applications, at 25%. For commercial systems, Scale Microgrid Solutions has the largest share, at 25%. The total number of contractors with at least one application has grown from 54 to 68.

Table 3-14. Number of Approved or Completed Applications by Contractor

Contractor	Residential Applications	C&I Applications	Total Applications
Earthlight Technologies, LLC	325	8	333
Posigen, CT	159	0	159
Tesla	154	0	154
Venture Home Solar, LLC	79	0	79
Earth Smart Solar	75	0	75
SAVKAT, Inc.	75	0	75
Green Power Energy, LLC	70	0	70
Helio Solar LLC	38	0	38
West Electric LLC	32	0	32
Eastern CT Solar LLC	31	0	31
Tesla Energy Operations, Inc.	27	0	27
Aegis Solar Energy	25	0	25
Ion Solar Pros	23	0	23
CES Danbury LLC DBA Ross Solar Group	21	0	21
EcoSmart Home Services	19	0	19
Infinity Solar Systems	18	0	18
Scale Microgrid Solutions LLC	0	18	18
Premier Improvements Solar	16	0	16
Sunrun Installation Services Inc.	14	0	14
Honeywell International, Inc.	0	14	14
EcoSolar Installations, LLC	11	0	11
Synergy Smart Homes	10	0	10
Summer Hill Solar	9	0	9
Connecticut Solar Power LLC	8	0	8
Sunlight Solar Energy, Inc.	7	0	7
CPower	0	7	7
RWE Clean Energy, LLC	0	7	7
Shoreline Solar	6	0	6
Kinsley Group, Inc.	0	6	6
Trinity Solar, Inc.	5	0	5
Daisy Solutions, LLC	0	5	5
Apex Electrical Contractors LLC	4	0	4
Efficient Lighting Consultants, Inc. (ELC)	4	0	4
Son Energy Systems	4	0	4
PurePoint Energy LLC	3	1	4
Evergreen Energy. LLC	3	0	3
Powur PBC	3	0	3
Shoreline Solar LLC	3	0	3
SunTegra Energy LLC	3	0	3
Synergy Electrical Contracting LLC	3	0	3
Bright Light Energy Corp	2	0	2

Contractor	Residential Applications	C&I Applications	Total Applications
Crocker Consulting Inc DBA Omega Energy	2	0	2
Franklin WH	2	0	2
Newport Electric Construction Corp.	2	0	2
Shedd Technologies LLC	2	0	2
Cadenza Innovation, Inc.	1	1	2
HQCA Energy Solutions, LLC	0	2	2
Beacon Solar Construction INC	1	0	1
BigEnergy USA LLC	1	0	1
CSS On Demand Electrical LLC	1	0	1
Dyna Electric	1	0	1
Elite Electrical Contractors, LLC	1	0	1
Griffin Electrical Contractors Inc.	1	0	1
Harvest Power LLC	1	0	1
Insight Solar	1	0	1
Jack Rabbit Energy Independence LLC	1	0	1
Momentum Solar	1	0	1
Ovanova	1	0	1
Porticade Construction LLC, DBA Action Solar	1	0	1
Sol Power LLC	1	0	1
SunBug Solar	1	0	1
Sunrise Solar Consulting LLC	1	0	1
Sunrite Solar LLC	1	0	1
TotalEnergies Distributed Generation USA, LLC	1	0	1
West Hartford Solar, LLC	1	0	1
DownEast Renewable Energy LLC	0	1	1
EPC Energy Inc	0	1	1
Waldron Engineering & Construction, Inc.	0	1	1

Note: Counts include only projects in the "approved" or "completed" stages. As detailed in Section 3.1.5, the hybrid project is treated as a single C&I application for the purposes of this table. Additionally, CES Danbury LLC DBA Ross Solar Group was purchased by RWE Clean Energy, LLC (formerly ConEdison Solutions); therefore, its 21 residential applications are attributed to RWE Clean Energy, LLC. Additionally, 328 residential projects transferred into ESS from ConnectedSolutions, for which the contractor field was labeled "ConnectedSolutions," have been excluded from this table.

Source: *CES analysis of Connecticut Green Bank program tracking data through June 30, 2026.*

Administrative costs associated with the ESS Program for 2024 are provided in **Table 3-15** below. Costs are largely in line with last year, with declines primarily in evaluation, measurement, and verification and IT costs.

Table 3-15. Program Administrative Costs ($)

Cost Category	2023 Costs	2024 Cost	2025 Cost
Personnel	$1,032,678	$1,408,533	$1,459,103
Evaluation, Measurement, and Verification	$216,344	$315,032	$98,415
Marketing	$159,125	$120,329	$111,970
IT	$46,840	$348,173	$284,143
Other	$756,027	$251,041	$300,636
Total	**$2,211,014**	**$2,443,108**	**$2,256,292**

Note: EM&V primarily covers the cost of vendors supporting the Program Administrators in complying with Orders in various ESS dockets. The IT includes the cost of Distributed Energy Resource Management System vendors.

Source: *Program Administrators.*

Estimated upfront and enrollment incentives (i.e., including both Legacy and Construct 5) are presented in **Table 3-16**. Total incentives encumbered are effectively flat from the last report, with an increase in residential and commensurate decrease in commercial. While residential incentives have doubled since the last report, with significant increases in both the approved and completed categories, C&I incentives have fallen, due to project cancellations. Because Construct 5 enrollment incentives are much lower than upfront incentives, the values under Submitted and Approved are expected to decrease in future reports.

Table 3-16. Estimated Upfront Incentives Encumbered by Project Status ($)

Utility	Customer Type	Project Status as of June 30, 2025			
		Submitted ($)	Approved ($)	Completed ($)	Total ($)
Eversource	Residential Standard	$36,947	$795,629	$4,597,856	$5,430,432
	Residential Underserved	$6,360	$304,223	$1,099,271	$1,409,853
	Residential Low-Income	$0	$354,296	$630,349	$984,645
	Residential Subtotal	***$43,307***	***$1,454,147***	***$6,327,476***	***$7,824,930***
	Small C&I	$0	$3,864,856	$663,759	$4,528,614
	Medium C&I	$0	$10,557,153	$0	$10,557,153
	Large C&I	$0	$21,820,631	$114,819	$21,935,450
	C&I Subtotal	***$0***	***$36,242,639***	***$778,578***	***$37,021,217***
	Eversource Subtotal	**$43,307**	**$37,696,786**	**$7,106,053**	**$44,846,147**
United Illuminating	Residential Standard	$405	$117,334	$436,390	$554,128
	Residential Underserved	$450	$211,340	$166,488	$378,278
	Residential Low-Income	$0	$1,036,346	$0	$1,036,346
	Residential Subtotal	***$855***	***$1,365,019***	***$602,878***	***$1,968,751***
	Small C&I	$0	$349,415	$0	$349,415
	Medium C&I	$0	$689,293	$60,200	$749,493
	Large C&I	$0	$3,340,324	$0	$3,340,324
	C&I Subtotal	***$0***	***$4,379,032***	***$60,200***	***$4,439,232***
	UI Subtotal	**$855**	**$5,744,051**	**$663,078**	**$6,407,984**
Total Incentives Encumbered: Residential		**$44,162**	**$2,819,166**	**$6,930,353**	**$9,793,681**
Total Incentives Encumbered: C&I		**$0**	**$40,621,672**	**$838,778**	**$41,460,449**
Total Incentives Encumbered ($)		**$44,162**	**$43,440,837**	**$7,769,131**	**$51,254,130**

Note: This table includes both upfront incentives for Legacy systems and enrollment incentives for Construct 5 systems. Incentives for submitted and approved projects are estimated based on system capacity and applicable priority status, while incentives for completed projects reflect actual payments made for installed system. The hybrid project's upfront incentive, further detailed in Section 3.1.5, has been fractionalized per guidance from the Green Bank, with 48% to United Illuminating's Residential Low-Income and 52% to United Illuminating's Large C&I.

Source: *CES analysis of Connecticut Green Bank program tracking data through June 30, 2026.*

Table 3-17 and **Table 3-18** provide average upfront incentives for Legacy projects and enrollment incentives for Construct 5, respectively, on a per participant basis. For Legacy systems, residential incentives have remained effectively flat on a per project basis, while commercial incentives have decreased modestly, tracking the decrease in average commercial project size. **Table 3-18** illustrates the reduction in upfront/enrollment incentives as the program moves to Construct 5. The residential Eversource values for Underserved and Low-Income projects are considerably higher than for Standard residential customers. This is not because there are higher enrollment incentives; instead, this is a combination of a low sample size, larger (on a kWh basis) Underserved and Low-Income projects, and a higher proportion of the Underserved and Low-Income projects being on the Grid Edge. While the "N/A" under the commercial lines could indicate that no incentives have been provided (as there is no enrollment incentive for non-Priority commercial customers), in this case, the "N/A" indicates that there are no approved commercial Construct 5 projects at the time of the analysis.

Table 3-17. Average Total Project Upfront Incentive for Legacy Projects ($/Participant)

Utility	Customer Type	Average Upfront Incentive ($/Participant)
Eversource	Residential Standard	$7,366
	Residential Underserved	$10,287
	Residential Low-Income	$11,209
	Residential Average	***$8,139***
	Small C&I	$377,385
	Medium C&I	$621,009
	Large C&I	$707,595
	C&I Average	***$617,020***
	Eversource Average	**$44,709**
United Illuminating	Residential Standard	$6,644
	Residential Underserved	$7,840
	Residential Low-Income	$5,922
	Residential Average	***$6,419***
	Small C&I	$174,708
	Medium C&I	$149,899
	Large C&I	$668,065
	C&I Average	***$369,936***
	UI Average	**$20,136**
Average Incentives Encumbered by Residential Participants		**$7,716**
Average Incentives Encumbered by C&I Participants		**$575,840**
Average Project Incentive		**$38,775**

Note: The analysis of average total project incentives includes only Legacy projects in the "approved" or "completed" stages. Because of the limited installed cost data collected for projects only participating in active dispatches, the table above includes only those projects participating in active and passive events (i.e., those that have received an upfront incentive). The hybrid project's upfront incentive, further detailed in Section 3.1.5, has been fractionalized per guidance from the Green Bank, with 48% to United Illuminating's Residential Low-Income and 52% to United Illuminating's Large C&I.

Source: *CES analysis of Connecticut Green Bank program tracking data through June 30, 2026.*

Table 3-18. Average Total Project Upfront Incentive for Construct 5 Projects ($/Participant)

Utility	Customer Type	Average Upfront Incentive ($/Participant)
Eversource	Residential Standard	$2,156
	Residential Underserved	$4,998
	Residential Low-Income	$3,140
	Residential Average	***$2,480***
	Small C&I	N/A
	Medium C&I	N/A
	Large C&I	N/A
	C&I Average	***N/A***
	Eversource Average	**$2,480**
United Illuminating	Residential Standard	$1,125
	Residential Underserved	$745
	Residential Low-Income	N/A
	Residential Average	***$935***
	Small C&I	N/A
	Medium C&I	N/A
	Large C&I	N/A
	C&I Average	***N/A***
	UI Average	**$935**
Average Incentives Encumbered by Residential Participants		**$2,372**
Average Incentives Encumbered by C&I Participants		**N/A**
Average Project Incentive		**$2,372**

Note: The analysis of average total project incentives includes only Construct 5 projects in the "approved" or "completed" stages.

Source: *CES analysis of Connecticut Green Bank program tracking data through June 30, 2026.*

Table 3-19 provides project costs per participant. Residential costs have remained relatively stable. Interestingly, for residential projects, average total costs have decreased slightly more than battery only costs. While the underlying cost data may not be sufficiently reliable to draw conclusions, this would suggest a reduction in balance of system costs, which could include interconnection, profit, and soft costs. Average commercial costs have come down, though this is primarily attributable to the reduction in average project size.

Table 3-19. Average Project Cost ($/Participant)

Utility	Customer Type	Battery Only Cost ($/Participant)	Total Energy Storage System Cost ($/Participant)
Eversource	Residential Standard	$20,038	$32,302
	Residential Underserved	$20,179	$30,626
	Residential Low-Income	$20,298	$27,144
	Residential Average	***$20,081***	***$31,599***
	Small C&I	$792,126	$1,268,454
	Medium C&I	$2,098,373	$3,411,557
	Large C&I	$2,386,498	$4,211,877
	C&I Average	***$1,985,988***	***$3,396,435***
	Eversource Average	**$132,205**	**$223,510**
United Illuminating	Residential Standard	$20,622	$31,904
	Residential Underserved	$19,680	$28,662
	Residential Low-Income	$7,463	$12,306
	Residential Average	***$13,041***	***$20,318***
	Small C&I	$820,610	$968,965
	Medium C&I	$944,036	$1,345,099
	Large C&I	$2,445,395	$4,418,848
	C&I Average	***$1,549,031***	***$2,563,139***
	UI Average	**$70,283**	**$115,082**
Average Cost for Residential Participants		**$18,405**	**$28,913**
Average Cost for C&I Participants		**$1,913,162**	**$3,257,552**
Average Cost per Participant		**$117,694**	**$198,100**

Note: Average system cost estimates are based solely on projects in the "approved" or "completed" stages. Because of the limited installed cost data collected for projects only participating in active dispatch, the table above includes only those projects participating in active and passive events (i.e., those that have received an upfront incentive). Total energy storage system costs include the battery module as well as associated balance of system components, inverters, engineering and design, interconnection, monitoring, and permitting expenses. These costs do not include solar PV modules, although some shared balance-of-system and installation costs may be reflected due to PV pairing. The hybrid project's energy storage system cost, further detailed in Section 3.1.5, has been fractionalized per guidance from the Green Bank, with 48% to United Illuminating's Residential Low-Income and 52% to United Illuminating's Large C&I. The project is counted as 161 participants under United Illuminating's Residential Low-Income and 1 participant under United Illuminating's Large C&I.

Source: *CES analysis of Connecticut Green Bank program tracking data through June 30, 2026.*

Table 3-20 provides total installed costs by project status, utility, and customer type. As of June 30, 2026, the ESS Program has incentivized the installation of more than $33 million of energy storage systems, with an additional $239.5 million of projects in the approved stage.

Table 3-20. Total Installed Costs Allocated to Participants by Project Status ($)

Utility	Customer Type	Project Status as of June 30, 2026			
		Submitted ($)	Approved ($)	Completed ($)	Total ($)
Eversource	Residential Standard	$405,709	$4,090,610	$20,860,202	$25,356,521
	Residential Underserved	$95,838	$1,031,840	$3,225,231	$4,352,909
	Residential Low-Income	$0	$896,556	$1,546,394	$2,442,950
	Residential Subtotal	***$501,547***	***$6,019,006***	***$25,631,827***	***$32,152,380***
	Small C&I	$0	$12,030,160	$3,191,283	$15,221,443
	Medium C&I	$0	$57,996,464	$0	$57,996,464
	Large C&I	$0	$129,652,099	$916,103	$130,568,202
	C&I Subtotal	***$0***	***$199,678,723***	***$4,107,386***	***$203,786,109***
	Eversource Subtotal	**$501,547**	**$205,697,729**	**$29,739,213**	**$235,938,489**
United Illuminating	Residential Standard	$22,595	$706,244	$2,094,047	$2,822,886
	Residential Underserved	$21,353	$741,863	$705,459	$1,468,675
	Residential Low-Income	$0	$2,153,599	$0	$2,153,599
	Residential Subtotal	***$43,948***	***$3,601,706***	***$2,799,506***	***$6,445,160***
	Small C&I	$0	$1,937,930	$0	$1,937,930
	Medium C&I	$0	$6,207,997	$517,500	$6,725,497
	Large C&I	$0	$22,094,242	$0	$22,094,242
	C&I Subtotal	***$0***	***$30,240,169***	***$517,500***	***$30,757,669***
	UI Subtotal	**$43,948**	**$33,841,875**	**$3,317,006**	**$37,202,829**
Total Allocated Installed Costs: Residential		**$545,495**	**$9,620,712**	**$28,431,333**	**$38,597,540**
Total Allocated Installed Costs: C&I		**$0**	**$229,918,892**	**$4,624,886**	**$234,543,778**
Total Installed Costs ($)		**$545,495**	**$239,539,604**	**$33,056,219**	**$273,141,318**

Note: Total installed costs reflect costs associated with the battery module, balance of system components, inverter, engineering and design, interconnection, monitoring, and permitting. These figures do not include the cost of solar PV modules, although some balance-of-system and installation costs presented here may overlap with those associated with co-located solar PV systems. The hybrid project's installed cost, further detailed in Section 3.1.5, has been fractionalized per guidance from the Green Bank, with 48% to United Illuminating's Residential Low-Income and 52% to United Illuminating's Large C&I.

Source: *CES analysis of Connecticut Green Bank program tracking data through June 30, 2026.*

Table 3-21 highlights per unit ($/kW and $/kWh) energy storage system costs. Most residential $/kWh costs have remained effectively flat or have decreased. These costs are somewhat lower for approved projects than for completed projects, suggesting that average program costs will decrease somewhat. Commercial $/kWh costs for approved applications are effectively flat. For approved and completed projects, residential Underserved and Low-Income unit costs are higher than Standard; while, as shown in **Table 3-12**, residential Standard projects are, on average, somewhat larger, it is unclear that the difference in project size and implied economies of scale would explain the differences in per unit costs. On the other hand, **Figure 3-1** indicates that these differences in costs may be declining over time. While the cost of completed commercial projects has increased noticeably, the small sample size makes extrapolating from this change dubious.

Table 3-21. Average Total Energy Storage System Costs ($/kWh and $/kW)

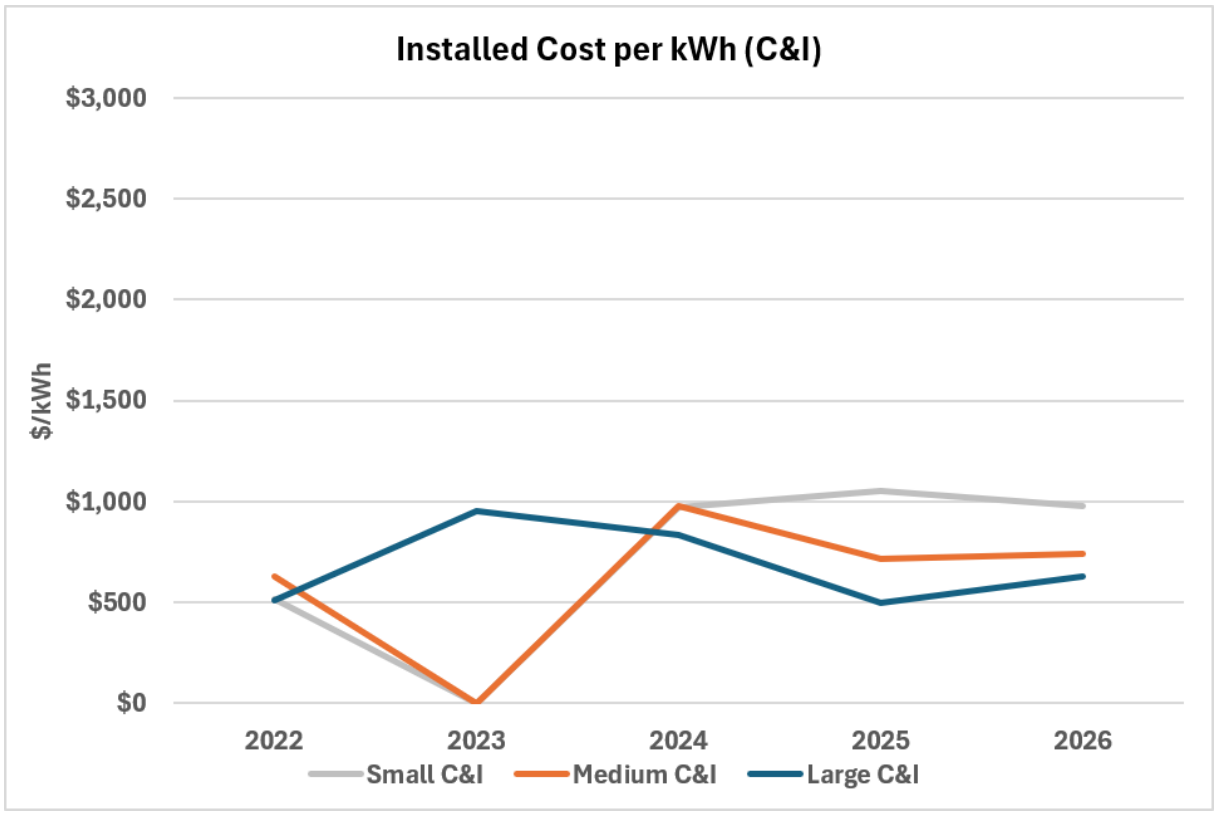
Customer Type	Submitted ($/kW)	Approved ($/kW)	Completed ($/kW)	Submitted ($/kWh)	Approved ($/kWh)	Completed ($/kWh)
Residential Standard	$1,741	$2,013	$2,303	$973	$1,165	$1,283
Residential Underserved	$1,573	$2,835	$2,440	$1,166	$1,340	$1,310
Residential Low-Income	N/A	$3,524	$2,832	N/A	$1,489	$1,367
Residential Average	***$1,702***	***$2,329***	***$2,345***	***$1,009***	***$1,246***	***$1,291***
Small C&I	N/A	$2,039	$5,106	N/A	$633	$1,043
Medium C&I	N/A	$2,131	$3,343	N/A	$837	$1,504
Large C&I	N/A	$1,602	$1,808	N/A	$665	$792
C&I Average	***N/A***	***$1,745***	***$3,595***	***N/A***	***$703***	***$1,014***
Overall Average	**$1,702**	**$1,759**	**$2,465**	**$1,009**	**$713**	**$1,243**

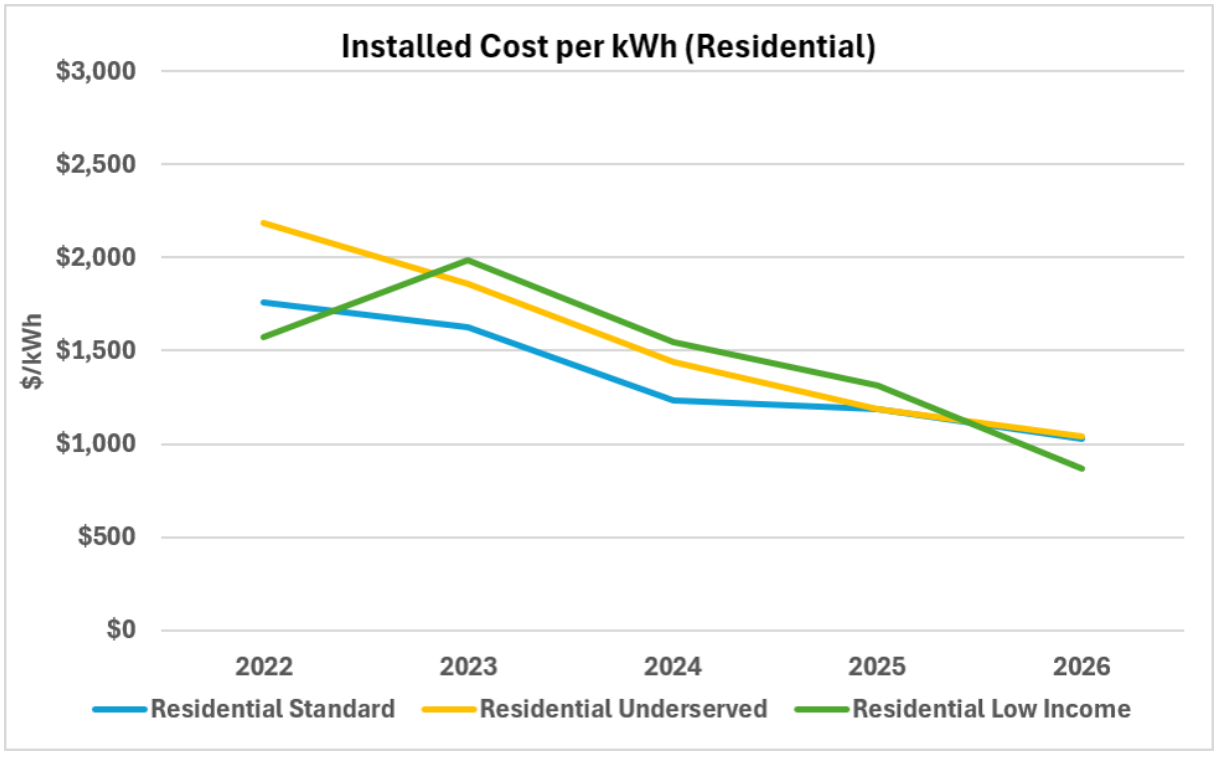
Note: Total energy storage system costs include the battery module as well as associated balance of system components, inverters, engineering and design, interconnection, monitoring, and permitting expenses. These costs do not include solar PV modules; however, some balance-of-system and installation costs may overlap due to PV pairing and would not have been incurred otherwise. Because of the limited installed cost data collected for projects only participating in active dispatch, the table above includes only those projects participating in active and passive events (i.e., those that have received an upfront incentive). As detailed in Section 3.1.5, the hybrid project is treated as a single Large C&I system for the purposes of this table. Additionally, due to the relatively low number of completed or submitted projects within certain customer segments (e.g., submitted project statuses), average cost estimates for those segments may not be fully representative.

Source: *CES analysis of Connecticut Green Bank program tracking data through June 30, 2026.*

Figure 3-1 illustrates how average costs have evolved over time, based on application approval date. Given that there is the greatest number (by count) of Residential Standard systems, this set of systems may provide the best view of how costs have evolved, based on date of completed application. This would suggest that there has been a monotonic decline in average kWh costs over time. The chosen metric ($/kWh) is a good indicator, but also an imperfect metric, as increased project sizes and durations would decrease $/kWh costs. Still, because project performance is generally energy-limited (that is, project performance during events is limited by available kWh as opposed to power (kW)), this is a key indicator for project costs. There is not a clear trend for C&I projects.

Figure 3-1. Average Total Energy Storage System Cost by Application Year ($/kWh)





Note: For the commercial systems, no small or medium projects with a 2023 approval date are included in the dataset; the dip in the lines indicates an absence of data, not a decrease in costs. Only projects in the submitted, approved, or completed categories are included. Total energy storage system costs include the battery module as well as associated balance of system components, inverters, engineering and design,

interconnection, monitoring, and permitting expenses. These costs do not include solar PV modules; however, some balance-of-system and installation costs may overlap due to PV pairing and would not have been incurred otherwise. As detailed in Section 3.1.5, the hybrid project is treated as a single Large C&I system for the purposes of this table. Missing data points indicate no projects had applications approved during the applicable year.

Source: *CES analysis of Connecticut Green Bank program tracking data through June 30, 2026.*

Table 3-22 provides similar information, but for battery-only costs. The trends generally mirror those demonstrated in the previous table. Given the number of participating contractors and the variations in project configuration, it is likely that inconsistent cost categorization would make drawing conclusions about trends in battery costs challenging.

Table 3-22. Average Battery-Only Costs ($/kWh and $/kW)

Customer Type	Submitted ($/kW)	Approved ($/kW)	Completed ($/kW)	Submitted ($/kWh)	Approved ($/kWh)	Completed ($/kWh)
Residential Standard	$3,437	$1,598	$1,496	$2,640	$906	$830
Residential Underserved	N/A	$2,208	$1,662	N/A	$1,075	$882
Residential Low-Income	N/A	$2,919	$2,172	N/A	$1,232	$1,037
Residential Average	***$3,437***	***$1,901***	***$1,548***	***$2,640***	***$998***	***$848***
Small C&I	N/A	$1,287	$3,729	N/A	$399	$762
Medium C&I	N/A	$1,327	$2,678	N/A	$521	$1,205
Large C&I	N/A	$904	$1,188	N/A	$375	$521
C&I Average	***N/A***	***$1,020***	***$2,602***	***N/A***	***$411***	***$734***
Overall Average	**$3,437**	**$1,037**	**$1,651**	**$2,640**	**$420**	**$828**

Note: Battery-only costs are intended to only include costs associated with the battery modules themselves, excluding costs balance of system components, inverters, engineering and design, interconnection, monitoring, and permitting expenses. These costs do not include solar PV modules; however, some balance-of-system and installation costs may overlap due to PV pairing and would not have been incurred otherwise. Where battery modules and inverters are integrated, costs may not be accurately allocated across these categories. As detailed in Section 3.1.5, the hybrid project is treated as a single Large C&I system for the purposes of this table. Additionally, due to the relatively low number of completed or submitted projects within certain customer segments (e.g., submitted project statuses), average cost estimates for those segments may not be fully representative.

Source: *CES analysis of Connecticut Green Bank program tracking data through June 30, 2026.*

3.3. Findings and Recommendations

Table 3-23. Program Tracking Metrics Findings and Recommendations

Finding	Recommendation
The C&I pipeline appears to have stagnated, with new applications slowing, including no applications since the implementation of Construct 5.	The Program Administrators should continue to monitor the pace of incoming C&I applications and continue to remain engaged with contractors, developers, and host customers to understand barriers to participation. The Program Administrators should explicitly seek feedback on the viability of projects under Construct 5. The Program Administrators

Finding	Recommendation
	may consider focus groups or other structured feedback to identify barriers to development that could be addressed, outside of increased incentive levels.
Decreases in per unit residential costs are not mirrored in commercial cost data.	Building on the recommendation above, the Program Administrators should consider a more detailed evaluation of commercial project cost drivers. For example, the greater heterogeneity of commercial sites and customer needs, relative to residential sites, may be a cost driver. The Program Administrators should consider tools that could be used to help address these soft costs (or other mechanisms for driving down commercial costs).
Attrition of the commercial pipeline is outpacing new applications.	While significant attrition in the commercial pipeline has been expected, the Program Administrators should review the characteristics of canceled commercial projects. This could help refine future projections and identify key barriers.
The program is falling short of its target of 40% Low-Income and Underserved residential participation rates.	Affordable multifamily buildings provide significant numbers of participants, but only one has progressed through the program. The Program Administrators should evaluate any new potential strategies or program improvements for increasing Low-Income and Undeserved participation rates and opine on whether they are likely to be able to reach the 40% target without additional affordable multifamily housing projects. In addition, ongoing efforts, such as third-party ownership support and technical assistance programs (including Solar Marketplace Assistant Program Plus or Solar MAP+), offered by the Green Bank, should be continued and improved.
Gaps in the data for certain project categories (e.g., self-enrolling participants, Active Only participants, and projects transferred from ConnectedSolutions) are leading to some challenges in evaluating data.	The Program Administrators should consider other methods for collecting data from ESS participants. When data cannot be collected, the Program Administrators should increase the consistency in how data gaps are represented in the enrollment data.

Source: *CES analysis*

1. Program Evaluation Metrics

This section provides program evaluation metrics, based on the evaluated performance of systems participating in the ESS program.

4.1. Program Evaluation Metrics

The first set of tables (4-1 through 4-6) evaluate performance of participants for Active summer events, Active winter events, and Passive events, by residential and C&I. These tables are intended to illustrate trends in participant performance (evaluating how systems perform relative to their hypothetical output) as well as total enrollment and kW reductions. In these tables, per

participant metrics are evaluated exclusively for systems that had a net discharge of greater than 0 kWh over the course of the evaluated event, filtering out resources that did not discharge during the event. It should also be noted that Expected Average Power is equal to the Battery Energy Availability (available energy reported at the beginning of the event) divided by the duration of the event (varies for active events, always 3 hours for Passive events). While the calculation does not account for resources which may be limited by their power rating, given the duration of systems (which are less than the duration of events in most instances, even with a fully charged battery) participating in the program, this is not likely to significantly impact the results. This calculation also does not apply an assumed reserve; said differently, it assumes that participants discharge all available energy down to zero by the end of the event. This approach is applied to both Active and Passive events, to aid in making direct comparisons. The data shows that, in most instances, resources do not discharge to a state of charge below 20%; this is attributable to several factors, including the methodology for scoring Passive performance, the desire for systems to retain some energy in case of an outage event, and the reduced degradation associated with not fully discharging a BESS.

Because Eversource and UI did not always call events on the same days (or during the same hours), the number of eligible systems fluctuates, as events may include both utilities, or just one of them. Also note that, in cases where data for an individual resource on an individual event day was eliminated, this would reduce the number of participants, but not the number of eligible systems. Eliminated data is ignored in other fields (e.g., it is not considered in Battery Energy Availability).

Table *4-1*, below, evaluates residential performance during summer Active events. As additional systems enroll, the expected and delivered kW reductions increase over the course of the season. Participation rates (again, defined as count of systems with net discharge during the event divided by the number of systems enrolled and capable of participating in the event) are consistently high and have improved from an average of 74% in summer 2024 to 88% in summer 2025. Significant changes in participation rates from day to day within the data set are, in part, explained by outage protection events. For example, Enphase implemented outage protection on July 8, 2025 for the majority of its systems causing them to not discharge during the Active event on that day; this is reflected by a significant decrease in participating systems on that date.

Battery availability per participant is also reasonably consistent and indicates that most systems are starting with a reasonably high state of charge. This value has also increased considerably from last year's data. This is attributable primarily to an increase in the nameplate capacity of participating systems; however, starting state of charge for participating systems also increased, from approximately 88% to 96%. Because other columns are based on available energy (as opposed to nameplate energy capacity), this increase in starting state of charge is an improvement in performance that is incremental to the improvement in performance reflected in the final column (% of Maximum Expected Power per Event).

Per participant average power per event is also reasonably stable. Performance relative to expected performance, as measured in the final column, has increased significantly from the previous evaluation, from 59% to 67%. Interestingly, this value also fluctuates significantly over the course of summer 2025. This is not clearly attributable to a single factor. In the last evaluation, there was a clear difference in participation between two-hour and three-hour events, with participation higher in three-hour events, indicating that systems may not be changing their dispatch strategy based on whether an event was two or three hours long. This is no longer the case as performance (as % of maximum possible) is higher for two-hour events than three-hour

events, indicating that dispatch is more appropriately factoring in event duration. Instead, the variation in performance is attributable to a range of factors including:

- The impact of outage events, as some resources in outage protection mode will still discharge some energy during events, causing them to be counted as a participant
- Different starting state of charge, as, while the metric is based off of starting available energy, because most resources will not discharge down to 0% state of charge, a lower starting state of charge will tend to reduce the calculated performance (e.g., if a resource starts at 20% state of charge, it could score 100% by discharging to 0% state of charge, but, in practice, it may not discharge at all, which would yield a score of 0%)
- Failure to discharge available energy for other reasons

Table 4-1. Residential Program Evaluation Metrics by Active Event Date-Summer 2025 Season

Event Date	Eligible Systems [1]	Participants [2]	Active Event Participation %	Battery Energy Availability (kWh/ Participant)[3]	Battery Energy Availability (kWh/ Event)	Average Power per Event (kW/ program)	Maximum Expected Average Power Based on Energy Availability (kW/ Participant)	Average Power per Event (kW/ Participant)	% of Maximum Expected Power per Event (%)
6/24/2025	333	257	77%	31	8007	2607	15.6	10.1	65%
7/1/2025	341	329	96%	28	9114	1915	9.2	5.8	63%
7/2/2025	341	324	95%	27	8827	2955	13.6	9.1	67%
7/3/2025	341	248	73%	31	7759	1313	10.4	5.3	51%
7/5/2025	341	317	93%	28	8992	2056	9.5	6.5	69%
7/6/2025	341	314	92%	28	8870	2020	9.4	6.4	68%
7/7/2025	341	313	92%	27	8568	2915	13.7	9.3	68%
7/8/2025	300	219	73%	33	7286	1645	11.1	7.5	68%
7/9/2025	342	326	95%	28	9004	2974	13.8	9.1	66%
7/10/2025	342	330	96%	27	8808	2985	13.3	9.0	68%
7/11/2025	342	334	98%	27	9165	3073	13.7	9.2	67%
7/12/2025	347	336	97%	27	9218	2118	9.1	6.3	69%
7/13/2025	335	322	96%	28	8904	2074	9.2	6.4	70%
7/14/2025	347	293	84%	29	8360	1568	9.5	5.4	56%
7/15/2025	348	277	80%	31	8496	2739	15.3	9.9	64%
7/16/2025	348	270	78%	31	8400	2772	15.6	10.3	66%
7/17/2025	350	278	79%	30	8375	2760	15.1	9.9	66%
7/18/2025	350	343	98%	27	9426	3248	13.7	9.5	69%
7/20/2025	350	271	77%	31	8446	1741	10.4	6.4	62%
7/23/2025	350	293	84%	31	8939	2077	10.2	7.1	70%
7/24/2025	351	297	85%	30	9040	2961	15.2	10.0	66%
7/25/2025	351	273	78%	31	8543	2825	15.6	10.3	66%
7/26/2025	351	283	81%	31	8688	2886	15.3	10.2	66%

7/28/2025	351	285	81%	31	8707	1994	10.2	7.0	69%
7/29/2025	350	293	84%	30	8829	2888	15.1	9.9	65%
7/30/2025	350	275	79%	31	8544	2791	15.5	10.1	65%
7/31/2025	352	330	94%	27	8819	3004	13.4	9.1	68%
8/4/2025	307	300	98%	29	8763	2124	9.7	7.1	73%
8/5/2025	350	345	99%	27	9465	3315	13.7	9.6	70%
8/6/2025	351	312	89%	29	9021	1967	9.6	6.3	65%
8/7/2025	352	346	98%	28	9785	2355	9.4	6.8	72%
8/10/2025	354	349	99%	28	9805	2333	9.4	6.7	71%
8/11/2025	353	344	97%	28	9586	3368	13.9	9.8	70%
8/12/2025	354	347	98%	28	9668	3331	13.9	9.6	69%
8/13/2025	359	341	95%	28	9421	2713	13.8	8.0	58%
8/14/2025	358	349	97%	28	9667	3344	13.8	9.6	69%
8/15/2025	359	351	98%	28	9809	3398	14.0	9.7	69%
8/16/2025	359	353	98%	29	10140	3364	14.4	9.5	66%
8/17/2025	359	352	98%	29	10107	2362	9.6	6.7	70%
8/23/2025	365	362	99%	28	10290	2434	9.5	6.7	71%
8/24/2025	366	364	99%	29	10599	2381	9.7	6.5	67%
8/25/2025	366	360	98%	29	10502	2379	9.7	6.6	68%
Summer 2022 Average			100%	17	17	3.9	5.7	3.9	69%
Summer 2023 Average			74%	16	617	119	6.8	3.0	45%
Summer 2024 Average			88%	18	3069	839	8.5	4.9	59%
Summer 2025 Overall Average	**348**	**314**	**90%**	**29**	**9066**	**2573**	**12.3**	**8.2**	**67%**

Note: [1]Eligible Systems represents a count of BESS able to participate in an event, established by determining if the system had begun providing interval data.
[2]Participants, here, are defined as projects with a net discharge of greater than zero over the course of the event. Other fields denominated in per Participant only include resources that had a net discharge of greater than 0 over the course of the event (i.e., these metrics filter out resources that did not discharge during the event).
[3]Battery Energy Availability is based on energy available at the beginning of the event; it is not adjusted to account for a potential reserve. Similarly, the Maximum Expected Average Power Based on Energy Availability metric assumes that the resources are discharged to a state of charge of 0.
All averages represent simple averages of the per event values above; each event is not weighted.

Source: *CES analysis of telemetry data; 2022/2023 and 2023/2024 values from previous ESS Program EM&V annual report.*

Table 4-2 provides the same analysis, but for winter seasons. Unlike the 2024-2025 winter, participation across the two events is consistent and high. Performance (as measured by % of Maximum Expected Power) has increased substantially as well, with participation rates and performance at rates comparable to the Summer 2025 rates. This increased winter performance is valuable, given that winter dispatch will become more valuable to New England's grid over time. More systems participated in these events relative to the summer 2025 because more systems had enrolled by the beginning of the winter events.

Table 4-2. Residential Program Evaluation Metrics by Active Event Date-Winter 2025-2026 Season

Event Date	Eligible Systems[1]	Participants[2]	Active Event Participation %	Battery Energy Availability (kWh/Participant)[3]	Battery Energy Availability (kWh/Event)	Average Power per Event (kW/program)	Maximum Expected Average Power Based on Energy Availability (kW/Participant)	Average Power per Event (kW/Participant)	% of Maximum Expected Power per Event (%)
1/20/2026	521	485	93%	26	12769	4258	13.2	8.8	67%
1/30/2026	551	515	93%	26	13475	4412	13.1	8.6	65%
Winter 2022/2023 Average			79%	23	114	15	7.7	3	39%
Winter 2023/2024 Average			79%	12	1366	213	4.1	1.9	44%
Winter 2024/2025 Average			64%	27	3970	1046	13.7	7.3	54%
Winter 2025/ 2026 Average	**536**	**500**	**93%**	**26**	**13122**	**4335**	**13.1**	**8.7**	**66%**

Note: [1]Eligible Systems represents a count of BESS able to participate in an event, established by determining if the system had begun providing interval data.
[2]Participants, here, are defined as projects with a net discharge of greater than zero over the course of the event. Other fields denominated in per Participant only include resources that had a net discharge of greater than 0 over the course of the event (i.e., these metrics filter out resources that did not discharge during the event).
[3]Battery Energy Availability is based on energy available at the beginning of the event; it is not adjusted to account for a potential reserve. Similarly, the Maximum Expected Average Power Based on Energy Availability metric assumes that the resources are discharged to a state of charge of 0.
All averages represent simple averages of the per event values above; each event is not weighted.

Source: *CES analysis of telemetry data; 2022/2023 and 2023/2024 values from previous ESS Program EM&V annual report.*

Table 4-3 shows performance during residential Passive events. All metrics have improved relative to the Summer 2024, which, itself already shows a significant increase in performance. Note that these metrics do not replicate the Passive scoring methodology, but are calculated in the same way as the Active metrics in this report, enabling comparison. Because no reserve is assumed, the highest score possible, while maintaining a 20% reserve capacity (as required by the Program Manual for Passive events), would be 80%. In its Year 4 Final Decision, PURA directed Passive events to be reduced to three hours long – this first went into effect with the summer 2025 season. Because of how the metrics in the table are calculated, this change in event duration should not, in and of itself, change performance. Thus, the improvement is due to improved operations, not just the change in event duration. Participation rates, per participant energy availability, and % of maximum expected power per event all are comparable to Active events.

Table 4-3. Residential Program Evaluation Metrics by Passive Event Date Summer 2025

Event Date	Eligible Systems[1]	Participants[2]	Passive Event Participation %	Battery Energy Availability (kWh/Participant)[3]	Battery Energy Availability (kWh/Event)	Average Power per Event (kW/program)	Maximum Expected Average Power Based on Energy Availability (kW/Participant)	Average Power per Event (kW/Participant)	% of Maximum Expected Power per Event (%)
6/2/2025	261	250	96%	23	5806	1295	7.7	5.2	67%

6/3/2025	261	249	95%	24	5853	1333	7.8	5.4	68%
6/4/2025	261	243	93%	23	5683	1341	7.8	5.5	71%
6/5/2025	262	249	95%	23	5840	1335	7.8	5.4	69%
6/6/2025	262	245	94%	23	5750	1148	7.8	4.7	60%
6/9/2025	263	254	97%	23	5903	1324	7.7	5.2	67%
6/10/2025	267	251	94%	23	5704	1267	7.6	5.0	67%
6/11/2025	267	252	94%	23	5909	1359	7.8	5.4	69%
6/12/2025	270	257	95%	24	6049	1341	7.8	5.2	67%
6/13/2025	270	258	96%	24	6134	1348	7.9	5.2	66%
6/16/2025	270	258	96%	24	6143	1435	7.9	5.6	70%
6/17/2025	270	257	95%	22	5649	1278	7.3	5.0	68%
6/18/2025	272	249	92%	24	5955	1339	8.0	5.4	67%
6/20/2025	272	258	95%	23	6046	1430	7.8	5.5	71%
6/23/2025	272	245	90%	25	6071	1397	8.3	5.7	69%
6/25/2025	275	234	85%	25	5908	1179	8.4	5.0	60%
6/26/2025	275	261	95%	23	6077	1435	7.8	5.5	71%
6/27/2025	275	258	94%	24	6218	1396	8.0	5.4	67%
6/30/2025	275	225	82%	25	5684	1232	8.4	5.5	65%
7/8/2025	25	11	44%	21	232	15	7.0	1.4	20%
7/21/2025	292	271	93%	25	6640	1627	8.2	6.0	74%
7/22/2025	292	257	88%	25	6440	1517	8.4	5.9	71%
8/1/2025	293	272	93%	25	6713	1596	8.2	5.9	71%
8/4/2025	26	26	100%	19	483	116	6.2	4.5	72%
8/8/2025	296	276	93%	25	6889	1670	8.3	6.0	73%
8/18/2025	304	287	94%	25	7103	1746	8.2	6.1	74%
8/19/2025	304	278	91%	25	7000	1710	8.4	6.2	73%
8/20/2025	304	285	94%	24	6757	1581	7.9	5.5	70%
8/21/2025	310	286	92%	25	7092	1715	8.3	6.0	73%
8/22/2025	310	280	90%	25	7109	1717	8.5	6.1	72%
8/26/2025	310	295	95%	25	7490	1765	8.5	6.0	71%
8/27/2025	311	274	88%	26	7152	1630	8.7	5.9	68%
8/28/2025	309	248	80%	29	7100	1465	9.5	5.9	62%
8/29/2025	311	291	94%	25	7367	1764	8.4	6.1	72%
Summer 2023 Average			76%	15	535	55	3	1.6	53%
Summer 2024 Average			80%	16	2201	277	3.2	2.1	63%
Summer 2025 Average	**268**	**247**	**91%**	**24**	**5999**	**1378**	**8.0**	**5.4**	**67%**

Note: [1]Eligible Systems represents a count of BESS able to participate in an event, established by determining if the system had begun providing interval data.

[2]Participants, here, are defined as projects with a net discharge of greater than zero over the course of the event. Other fields denominated in per Participant only include resources that had a net discharge of greater than 0 over the course of the event (i.e., these metrics filter out resources that did not discharge during the event).

[3]Battery Energy Availability is based on energy available at the beginning of the event; it is not adjusted to account for a potential reserve. Similarly, the Maximum Expected Average Power Based on Energy Availability metric assumes that the resources are discharged to a state of charge of 0. It should be noted that the program rules directed participants to discharge to a state of charge of 20% during Passive events rather than discharge to 0%.
All averages represent simple averages of the per event values above; each event is not weighted.

Source: *CES analysis of telemetry data; 2022/2023 and 2023/2024 values from previous ESS Program EM&V annual report.*

The following set of tables provide the same metrics, but for C&I projects. In the commercial tables in the previous annual report, because of issues related to the reliability of the stored kWh field in the telemetry data, it was always assumed that the starting available energy was equal to the nameplate energy capacity (kWh). For this year's report, Battery Energy Availability is based on telemetry data for both Active and Passive events, not an assumed 100% state of charge. This also affects the Maximum Expected Average Power Based on Energy Availability and % of Maximum Expected Power per Event fields, as the calculations for both fields use starting energy as an input. In general, this change will tend to reduce Battery Energy Availability, decrease Maximum Expected Average Power Based on Energy Availability, and increase % of Maximum Expected Power per Event.

Table 4-4 below, provides information on the participation of C&I systems in active events during summer 2024. For most of the summer 2025 season, there were only 4 eligible systems, the same number as in the preceding summer. Given this limited number of projects, it is challenging to draw robust conclusions related to the anticipated performance of future systems. Still, the data show a remarkable improvement in performance, as measured by the % of Maximum Expected Power field, jumping from 34% to 64%, comparable to residential performance. As noted above, some of this is attributable to a change in the calculation; however, the relatively modest decrease in Battery Energy Availability (again, caused by using actual starting energy as opposed to assuming 100% state of charge at the beginning of the event) does not explain the increase in performance; thus, the majority of the improvement is attributable to improved dispatch. Note that some data quality issues which were addressed by removing the applicable system for a given event explain some of the events in which not all eligible systems participated as well as the considerable fluctuation in other metrics from event to event.

Table 4-4. C&I Program Evaluation Metrics by Active Event Date - Summer 2025 Season

Event Date	Eligible System`s[1]	Participants[2]	Active Event Participation %	Battery Energy Availability (kWh/ Participant)[3]	Battery Energy Availability (kWh/ Event)	Average Power per Event (kW/ program)	Maximum Expected Average Power Based on Energy Availability (kW/ Participant)	Average Power per Event (kW/ Participant)	% of Maximum Expected Power per Event (%)
6/24/2025	4	4	100%	418	1673	531	209	133	63%
7/1/2025	4	4	100%	585	2342	532	195	133	68%
7/2/2025	4	4	100%	582	2328	600	291	150	52%
7/3/2025	4	4	100%	593	2372	532	198	133	67%
7/5/2025	4	4	100%	592	2366	450	197	113	57%
7/6/2025	4	4	100%	595	2379	520	198	130	66%
7/7/2025	4	4	100%	577	2308	604	288	151	52%
7/8/2025	4	4	100%	593	2370	472	198	118	60%
7/9/2025	4	4	100%	538	2151	535	269	134	50%

7/10/2025	4	4	100%	533	2133	499	267	125	47%
7/11/2025	4	4	100%	511	2046	505	256	126	49%
7/12/2025	4	4	100%	538	2150	435	179	109	61%
7/13/2025	4	4	100%	560	2240	391	187	98	52%
7/14/2025	4	4	100%	470	1880	381	157	95	61%
7/15/2025	4	4	100%	507	2029	486	254	121	48%
7/16/2025	4	4	100%	566	2263	534	283	134	47%
7/17/2025	4	4	100%	520	2078	472	260	118	45%
7/18/2025	4	3	75%	604	1811	458	302	153	51%
7/20/2025	4	3	75%	610	1831	320	203	107	52%
7/23/2025	4	3	75%	602	1806	283	201	94	47%
7/24/2025	4	3	75%	604	1811	360	302	120	40%
7/25/2025	4	3	75%	605	1815	301	303	100	33%
7/26/2025	4	2	50%	642	1285	253	321	127	39%
7/28/2025	4	3	75%	608	1824	244	203	81	40%
7/29/2025	4	2	50%	642	1285	253	321	126	39%
7/30/2025	2	2	100%	642	1285	253	321	126	39%
7/31/2025	4	2	50%	504	1009	307	252	153	61%
8/4/2025	3	2	67%	533	1066	263	178	132	74%
8/5/2025	4	2	50%	470	939	342	235	171	73%
8/6/2025	3	2	67%	497	995	265	166	133	80%
8/7/2025	3	2	67%	518	1035	312	173	156	90%
8/10/2025	3	2	67%	516	1033	306	172	153	89%
8/11/2025	4	2	50%	515	1029	428	257	214	83%
8/12/2025	4	2	50%	507	1015	432	254	216	85%
8/13/2025	4	2	50%	502	1004	437	251	218	87%
8/14/2025	4	2	50%	508	1015	468	254	234	92%
8/15/2025	4	2	50%	508	1016	478	254	239	94%
8/16/2025	4	2	50%	509	1018	445	255	222	87%
8/17/2025	3	2	67%	517	1034	310	172	155	90%
8/23/2025	3	2	67%	512	1024	306	171	153	90%
8/24/2025	3	2	67%	514	1028	302	171	151	88%
8/25/2025	4	2	50%	510	1020	310	170	155	91%
		Summer 2023 Average	100%	660	660	3.4	125	3.4	2%
		Summer 2024 Average	79%	607	1274	201	286	96	34%
Summer 2025 Average	**4**	**3**	**78%**	**547**	**1622**	**403**	**232**	**143**	**64%**

Note: [1]Eligible Systems represents a count of BESS able to participate in an event, established by determining if the system had begun providing interval data.

[2]Participants, here, are defined as projects with a net discharge of greater than zero over the course of the event. Other fields denominated in per Participant only include resources that had a net discharge of greater than 0 over the course of the event (i.e., these metrics filter out resources that did not discharge during the event).

[3]Battery Energy Availability is based on energy available at the beginning of the event; it is not adjusted to account for a potential reserve. Similarly, the Maximum Expected Average Power Based on Energy Availability metric assumes that the resources are discharged to a state of charge of 0.

*As noted in the prose above, because of data quality issues, previous reports assumed that projects started with a 100% state of charge, instead of reporting the starting state of charge indicated by the telemetry data. This report shifts to using the actual starting state of charge. This change in approach makes direct comparisons between this year's report and previous reports for the indicated metrics potentially misleading.
All averages represent simple averages of the per event values above; each event is not weighted.

Table 4-5 provides the same analysis, but for winter seasons. Participation improved, with all systems participating in both events. An increase in % of Maximum Expected Power per Event, however, is largely attributable to the change in how Battery Energy Availability was calculated for commercial projects.

Table 4-5. C&I Program Evaluation Metrics by Active Event Date – Winter 2025-2026 Season

Event Date	Eligible Systems[1]	Participants[2]	Active Event Participation %	Battery Energy Availability (kWh/Participant)[3]	Battery Energy Availability (kWh/Event)	Average Power per Event (kW/program)	Maximum Expected Average Power Based on Energy Availability (kW/Participant)	Average Power per Event (kW/Participant)	% of Maximum Expected Power per Event (%)
1/20/2026	4	4	100%	519	2076	601	259.6	150.1	58%
1/30/2026	4	4	100%	424	1697	550	212.1	137.6	65%
	Winter 2023/2024 Average		100%	660	660	70	125	70	40%
	Winter 2024/2025 Average		75%	566	1644	450	283	142	51%
Winter 2025/2026 Overall Average	**4**	**4**	**100%**	**472**	**1887**	**575**	**235.8**	**143.9**	**61%**

Note: [1]Eligible Systems represents a count of BESS able to participate in an event, established by determining if the system had begun providing interval data.
[2]Participants, here, are defined as projects with a net discharge of greater than zero over the course of the event. Other fields denominated in per Participant only include resources that had a net discharge of greater than 0 over the course of the event (i.e., these metrics filter out resources that did not discharge during the event).
[3]Battery Energy Availability is based on energy available at the beginning of the event; it is not adjusted to account for a potential reserve. Similarly, the Maximum Expected Average Power Based on Energy Availability metric assumes that the resources are discharged to a state of charge of 0.
All averages represent simple averages of the per event values above; each event is not weighted.

Table 4-6 shows a significant improvement in Passive event commercial participation rates, relative to Summer 2024. Other metrics, however, remain relatively stable, with the change in Battery Energy Availability being the primary driver of the increase in % of Maximum Expected Power.

Table 4-6. C&I Program Evaluation Metrics by Passive Event Date Summer 2025

Event Date	Eligible Systems1	Participants2	Passive Event Participation %	Battery Energy Availability (kWh/Participant)3	Battery Energy Availability (kWh/Event)	Average Power per Event (kW/program)	Maximum Expected Average Power Based on Energy Availability (kW/Participant)	Average Power per Event (kW/Participant)	% of Maximum Expected Power per Event (%)
6/2/2025	4	4	100%	492	1969	370	164.1	92.4	56%
6/3/2025	4	4	100%	493	1972	374	164.3	93.6	57%
6/4/2025	4	4	100%	490	1960	385	163.3	96.3	59%
6/5/2025	4	4	100%	504	2018	391	168.1	97.7	58%
6/6/2025	4	4	100%	500	2001	391	166.8	97.8	59%
6/9/2025	4	4	100%	498	1990	384	165.8	96.0	58%
6/10/2025	4	4	100%	499	1996	383	166.3	95.8	58%
6/11/2025	4	4	100%	503	2013	394	167.7	98.4	59%
6/12/2025	4	4	100%	500	2001	388	166.8	97.0	58%
6/13/2025	4	4	100%	496	1983	387	165.2	96.7	59%
6/16/2025	4	4	100%	494	1976	382	164.7	95.4	58%
6/17/2025	4	4	100%	463	1850	356	154.2	89.1	58%
6/18/2025	4	4	100%	473	1893	364	157.8	90.9	58%
6/20/2025	4	4	100%	493	1971	389	164.2	97.3	59%
6/23/2025	4	4	100%	493	1973	324	164.4	80.9	49%
6/25/2025	4	4	100%	446	1783	411	148.6	102.8	69%
6/26/2025	4	4	100%	398	1593	335	132.7	83.8	63%
6/27/2025	4	4	100%	440	1760	396	146.6	99.0	68%
6/30/2025	4	4	100%	494	1976	401	164.6	100.2	61%
7/21/2025	4	3	75%	551	1653	327	183.7	109.0	59%
7/22/2025	4	3	75%	527	1580	300	175.5	100.0	57%
8/1/2025	4	3	75%	312	935	212	103.9	70.6	68%
8/8/2025	4	3	75%	279	838	281	93.1	93.8	101%
8/18/2025	4	3	75%	278	835	276	92.8	92.0	99%
8/19/2025	4	3	75%	278	834	272	92.7	90.8	98%
8/20/2025	4	3	75%	278	833	254	92.6	84.5	91%
8/21/2025	4	3	75%	278	834	275	92.7	91.5	99%
8/22/2025	4	2	50%	366	732	170	122.0	85.1	70%
8/26/2025	4	2	50%	364	727	169	121.2	84.6	70%
8/27/2025	4	2	50%	366	733	172	122.1	86.2	71%
8/28/2025	4	2	50%	362	725	160	120.8	79.9	66%
8/29/2025	4	2	50%	365	730	157	121.7	78.7	65%
		Summer 2024 Average	73%	605	1133	117	121	63.0	52%
Summer 2025 Average	**4**	**3**	**86%**	**430**	**1521**	**320**	**143.5**	**92.1**	**67%**

Note: [1]Eligible Systems represents a count of BESS able to participate in an event, established by determining if the system had begun providing interval data.
[2]Participants, here, are defined as projects with a net discharge of greater than zero over the course of the event. Other fields denominated in per Participant only include resources that had a net discharge of greater than 0 over the course of the event (i.e., these metrics filter out resources that did not discharge during the event).
[3]Battery Energy Availability is based on energy available at the beginning of the event; it is not adjusted to account for a potential reserve. Similarly, the Maximum Expected Average Power Based on Energy Availability metric assumes that the resources are discharged to a state of charge of 0. It should be noted that the program rules directed participants to discharge to a state of charge of 20% during Passive events rather than discharge to 0%.
All averages represent simple averages of the per event values above; each event is not weighted.

Source: *CES analysis of telemetry data; 2022/2023 and 2023/2024 values from previous ESS Program EM&V annual report.*

Table 4-7 evaluates delivered kW during specified periods of time, defined below. With the exception described below, the values are calculated based on the intersection of the specified period and events (e.g., only on-peak hours that occurred during an event). The Peak Periods defined below are based on the three-hour periods, by season, with the highest average ISO-NE load. The Average Power per Participant during the ISO-NE annual peak hour exceeded the Average Power during active events overall, even though the event was the first Active event of the season, with additional systems enrolling subsequently in the season. Power discharged during the peak hour also exceeded average discharge over the event. The rows below measuring "Total Dispatch…" yield significantly lower Average Power values, as they include hours during which there was neither an active nor Passive event. These low values should not be considered a problem to be solved, as the timing of active and Passive events is chosen to maximize the impact of storage discharging; low discharging (or charging) during other periods is appropriate.

Table 4-7. Evaluation Metrics by Seasonal Peak Event

Evaluation Metric	Residential Average Power per Participant (kW)	Residential Average Power per Program (kW)	C&I Average Power per Participant (kW)	C&I Average Power per Program (kW)	Residential Count of Days	C&I Count of Days
2025 ISO- NE Peak Hour (June 24, 2025, 6 p.m -7 p.m. ET)	14	3,384	155	620	1	1
Active Dispatch during Summer Peak Period (non-holiday weekdays 6 p.m.-9 p.m. ET, June-August)	8	2,365	163	485	31	31
Passive Dispatch during Summer Peak Period (non-holiday weekdays 6 p.m.-9 p.m. ET, June-August)	5	1,355	93	321	34	32
Active or Passive Dispatch during Summer Peak Period (non-holiday weekdays 6 p.m.-9 p.m. ET, June-August)	6	1,946	127	401	63	63
Total Dispatch during Summer Peak Period (non-holiday weekdays 6 p.m.-9 p.m. ET, June-August)	3	831	66	224	63	63
Active Dispatch During Winter Peak Period (non-holiday weekdays 5 p.m.-8 p.m. ET, December-January)	9	4,335	144	575	2	2
Total Dispatch During Winter Peak Period (non-holiday weekdays 5 p.m.-8 p.m. ET, December-January)	1	305	70	252	45	45

Note: Average Power per Participant (kW) excludes systems that were enrolled and eligible to participate in an event, but did not have a net discharge of greater than 0 over the course of the event. "Total Dispatch" metrics consider all hours in the defined period, while other metrics only consider hours falling within the events being evaluated (active or passive).

Source: *CES analysis of telemetry data*.

Table *4-8* evaluates how active events lined up with key peak periods. Specifically, it considers how active events aligned with daily peak hours, seasonal peaks, and annual peaks. Eversource called events aligning with summer peaks in 2023, 2024, and 2025; UI did not call an event during the summer 2024 annual peak. The summer 2025 peak occurred unusually early in the season, on June 24th; it was the first event called by both EDCs. Neither utility called an event during the Winter 2025/2026 peak hour, which occurred on January 25 between 1:00 and 2:00 p.m. The EDCs did not call an event on this date; it's also worth noting that it is unusual for the peak hour to have fallen in the early afternoon; the highest usage hours in the winter tend to be in the early evening. This peak demand also occurred in the midst of a prolonged cold snap, making it more challenging for the EDCs to determine when to call an event, given the maximum of five winter events for Legacy systems. Percentage of Active Events Aligned w/ Daily Peak Hour remained similar to the previous year.

Table 4-8. Peak Targeting Percentages

Utility	Percentage of Active Events Aligned w/Daily Peak Hour	Percentage of Active Events Aligned w/Seasonal Peak	Percentage of Active Events Aligned w/Annual Peak
Eversource	80%	71%	100%
UI	79%	57%	67%

Notes: Percentage of Active Events Aligned w/Seasonal Peak and Percentage of Active Events Aligned w/Annual Peak Percentage of Active Events Aligned w/ Daily Peak Hour are based on Summer 2025 and Winter 2025/2026 performance. For Percentage of Active Events Aligned w/ Daily Peak Hour, only days on which an event was called are considered (i.e., the number is not reduced due to active events not being called at all).

Source: CES analysis of program data and ISO-NE load data

CES chose to present alignment of Active events with daily peak hours only for days on which an event was called, as this metric should not penalize the decision to not call an event every day. **Table *4*-9** shows the top 30 days (evaluated by peak hour on each day) for Summer 2025 and indicates whether each utility called an event on that day. For the summer season, Eversource called events on 80% of these days, comparable to last year, while UI called events on 77% of these days, a noticeable increase from 63% in the previous year. A significant number of peak days on which no event was called occurred during June – as noted above, it was unusual for so many peak days to occur in June. Eversource called two fewer summer events than in 2024, while UI called four more. The table also shows how the total program kW discharged on a given day varied based on whether events were called or not. As expected, total kW discharged is lower on days with no Active event. Still, because of strong Passive performance on these days, there is significant discharged energy; on high load days on which no event was called, such as June 23 and June 25, resources participating in Passive events provided an "insurance policy," discharging some energy. As a smaller percentage of total project capacity participates in Passive events, the value of this "insurance policy" will decrease relative to total program capacity, increasing the importance of calling Active events on high demand days.

Interestingly, even on days with no active or passive events (e.g., June 22, 2025, which was a Sunday), there is still significant energy discharged. This may be attributable to projects discharging under other objective functions (e.g., demand charge management, retail rate arbitrage, or increasing self-consumption), projects set to discharge every day during specified hours, or other system settings.

Table 4-9. Active Events on Top 30 Load Days by Season

Rank	Summer 2025					
	MW	Date	Peak Hour Ending (Load Based)	Eversource	UI	Average Event Discharge (kW/program)
1	25,898	06/24/2025	19	Event	Event	2,607
2	24,831	07/29/2025	19	Event	Event	2,888
3	24,329	06/23/2025	19	No Event	No Event	1,878
4	24,249	06/25/2025	19	No Event	No Event	1,747
5	23,822	07/16/2025	19	Event	Event	2,772
6	23,581	07/30/2025	19	Event	Event	2,791
7	23,371	07/17/2025	20	Event	Event	2,760
8	23,051	07/15/2025	20	Event	Event	2,739
9	22,791	07/08/2025	19	Event	No Event	1,233
10	22,623	07/28/2025	19	Event	Event	1,994
11	22,595	08/11/2025	19	Event	Event	3,368
12	22,333	07/01/2025	19	Event	Event	1,915
13	22,246	08/12/2025	19	Event	Event	3,331
14	22,157	08/14/2025	19	Event	Event	3,344
15	22,044	08/13/2025	17	Event	Event	2,713
16	21,902	07/25/2025	15	Event	Event	2,825
17	21,690	07/07/2025	19	Event	Event	2,915
18	21,204	07/06/2025	19	Event	Event	2,020
19	21,197	07/24/2025	19	Event	Event	2,961
20	20,675	06/22/2025	20	No Event	No Event	585
21	20,457	08/17/2025	18	Event	Event	2,362
22	20,450	06/30/2025	20	No Event	No Event	1,739
23	20,269	07/20/2025	18	Event	Event	1,741
24	20,189	06/19/2025	19	No Event	No Event	535
25	20,118	07/14/2025	19	Event	Event	1,568
26	20,104	07/02/2025	20	Event	Event	2,955
27	19,812	07/03/2025	18	Event	Event	1,313
28	19,757	08/10/2025	19	Event	Event	2,333
29	19,360	07/09/2025	20	Event	Event	2,974
30	19,022	06/05/2025	19	No Event	No Event	1,879
Percent of top 30 days:				80%	77%	
Total events called in season:				42	40	

Note: Dates are ranked by each day's peak daily load.

Source: *CES analysis ESS program data and ISO-NE data*

Key battery performance metrics are provided in **Table *4-10***. Summer and winter availability are presented separately. Winter availability has increased significantly relative to last year's value of 69% - this may be influenced by data quality as well as the pattern of snow affecting data in last year's report; snowfall often preceded the events evaluated in that report, potentially affecting

the availability of energy at the beginning of events. The % of charging energy from solar metric considers all systems, including those not paired with solar. Estimated bill impacts are also provided. The negative numbers indicate that, due to round-trip efficiency losses, cycling the battery increased customer bills. Participants on time-of-use (TOU) rates realized modest bill savings, but a limited number of residential customers are on TOU rates (less than 1% for Eversource and 30% for UI). The increase per participant increased since last year; this is attributable to factors including a change in how the total bill savings were converted to per participant, a decrease in the ratio of on-peak to off-peak charges, and an increase in charging kWh per participant.

Table 4-10. Battery Performance Metric

Performance Metric	Value
Battery Availability (Uptime) % (Summer)	99.07%
Battery Availability (Uptime) % (Winter)	98.78%
% of Charging Energy from Solar	62.46%
Estimated Bill Savings ($)	-$87,040
Estimated Bill Savings ($/participant)	-$113

Notes: Battery availability is calculated as the percentage of energy storage systems with any energy available at the start of each active event for the evaluated period (summer 2025-winter 2025/2026). Solar Energy Used is calculated for all resources (including those that are not paired with solar) over the full evaluated period, May 1, 2025-April 30, 2026. Estimated bill savings are calculated for all residential systems for the same period, using actual telemetry data and accounting for % of participants on TOU rate, by utility, and utility-specific rates. The values above were only presented for residential systems, as load and solar data was not consistently available for C&I systems.

Source: *CES analysis of telemetry data; publicly filed residential tariffs for UI and Eversource; enrollment data provided by the Connecticut Green Bank.*

Estimated reductions in Carbon Dioxide (CO_2), Nitrogen Oxide (NO_x) and Sulfur Oxide (SO_X) emissions attributable to participating projects discharging active events are included in **Table *4-11***. Emissions rates used to produce these estimates are from the 2024 AESC and the EPA's AVERT model. The negative value for AVERT indicates that it was estimated that carbon emissions increased as a result of the program, while the AESC marginal emissions rates yielded a reduction in emissions. Currently, New England has relatively flat marginal emissions rates (i.e., rates stay relatively flat over the course of a day and over the course of a year). As a result, round-trip differences in emission rates during periods when ESS program participants are charging and discharging may be insufficient to overcome roundtrip efficiency losses. These values have increased (either more negative or more positive) relative to last year's report, primarily because of the larger volume of MWh charged/discharged.

The difference in results for AESC vs. AVERT also highlight limitations in applying historical (actual) telemetry data to projected marginal emissions rates. This approach yields misalignment between system conditions (e.g., load and marginal emissions rate) in the two datasets. This misalignment, in addition to ISO-NE's relatively flat marginal emissions rates, can make drawing robust conclusions about the impact on emissions challenging. ISO-NE does not regularly publish hourly emissions rates; therefore, projected impacts on emissions, in which consistent assumptions can be made for battery behavior and system conditions (again, primarily load and

emissions rate), may be more reliable than the type of historical analysis included in the Table below.

Table 4-11. Emissions Evaluation Metrics

Emissions Metric	Avoided Emissions, per EPA AVERT	Avoided Emissions, per 2024 AESC
Avoided CO2 (lbs.)	- 256,820 lb	120,099
Avoided NOx (lbs.)	80 lb	n/a
Avoided SOx (lbs.)	90 lb	n/a

Note: EPA's AVERT model was not updated with 2025 emissions data. Given this, 2023 emissions rates were used, aligning weekdays vs. weekends in the emissions and storage dispatch datasets. AVERT rounds outputs to the nearest 10. The AESC does not provide estimates of SO_X or NO_X emissions rates; it does provide marginal emissions rates projections for CO_2, CH_4, and N_2O.

Source: *CES analysis of the period from* May 1, 2025-April 30, 2026. *Emissions data from EPA's AVERT (https://www.epa.gov/avert) and AESC (https://www.synapse-energy.com/avoided-energy-supply-costs-new-england-aesc).*

Metrics associated with the performance of participating systems are provided in **Table *4-12***. The estimates of the frequency with which systems provided backup power during outages may be underestimates, as it is possible that outages affected the quality of provided interval data.

Table 4-12. Outage Metrics

Outage Duration	Participants Affected per Outage	Count of Outages	Count of Instances (counts each customer affected by each outage)	Instances Battery Provided Backup Power (#)	% of Instances Battery Provided Backup Power	Total kWh Dispatched
15 min or fewer	Less than 10 participants	61	118	Not calculated, as resolution of discharge data is less than duration of event		
15 min or fewer	Greater than 10 participants	0	0			
More than 15 min	Less than 10 participants	541	843	705	85%	2104
More than 15 min	Greater than 10 participants	0	0	0	n/a	0

Note: Count of outages established using outage IDs in data provided by EDCs. Where telemetry data at a given site during an outage was missing or eliminated because of data quality concerns, that instance was removed from the data summarized above. Instances of backup power not estimated for event lasting 15 minutes or fewer, given the resolution of the BESS discharge data.

Source: *CES analysis of interval data and outage data.*

4.2. Findings and Recommendations

Finding	Recommendation
Residential performance has improved across a number of dimensions, including participation rates, starting state of charge, and % of available energy discharged during events.	The Program Administrators should be commended for their efforts to improve performance. At the same time, they should continue to monitor performance in real time to engage in corrective actions with OEMs when necessary. The Program Administrators should emphasize oversight of new OEMs that may still be learning how to dispatch appropriately in the program.
The elimination of Passive dispatch under Construct 5 eliminates an "insurance policy" for failing to call active events during peak periods.	While the vast majority of program capacity still operates in Passive events, increasing volumes of capacity, enrolled under Construct 5, will not participate in Passive events. This increases the risks of failing to call active events at the most beneficial times. The Program Administrators should ensure that their strategy for calling events aligns with this risk. Furthermore, given that the Program Administrators do not have Passive events to provide some minimum level of performance for Construct 5 systems, PURA may consider, in the future, increasing the total number of allowed summer Active Events (from 60).
The Program Administrators occasionally miss calling events during peak periods, such as during Winter 2025-2026.	The Program Administrators may want to revisit some of the parameters specified for when and how many active events may be called, to reduce the number of peak hours not covered by an active event. Specifically, they should consider whether changes in winter parameters are warranted. For summer events, the PAs tend to call substantially fewer than the maximum allowable 60 events. While calling more events creates opportunity costs for program participants, calling more events to increase the probability of dispatching during peak hours and thus increasing the benefits delivered by the program may be warranted.
Outage protection settings on participating systems appear to have a substantial impact on participation rates and performance.	Because resiliency is a key goal of the program, the Program Administrators have not provided requirements or guidelines for appropriate storm protection settings (either customer settings, or how these storm protection events are administered by OEMs). The Program Administrators should collect information on parameters for storm protection events from OEMs and consider providing guidance in the future.

Source: *CES analysis*

2. Benefit-Cost Analysis

PURA and the Program Administrators have relied upon benefit cost analysis (BCA) to evaluate the performance of the program and inform its design and changes since the original conception of the program. Since the original BCA[20], the analysis has evolved to consider new test perspectives, account for different costs and benefits, incorporate updated assumptions (both based on actual results and changes in projected values), and reflect changes to the design in the program.

This section provides a description of the BCA methodology, highlights key changes to the analysis relative to the analysis filed in Docket No. 25-08-05[21], presents results from the BCA, and highlights associated findings and recommendations.

5.1. Benefit-Cost Model – Design and Use

Fundamentally, BCA is intended to enable policymakers, regulators, and program implementers to make informed decisions about the design and implementation of policies. Connecticut has used BCAs to inform the design of a variety of energy policies, including the Conservation & Load Management plans. Where practical and applicable, and where PURA has not specifically directed otherwise, the overall methodology and key assumptions used for the ESS BCA are based on the approach to BCAs conducted for the Conservation & Load Management plans and is in line with previous ESS Program BCAs.

Test Perspective/Cost Tests

Central to conducting BCA is the establishment of test perspectives. There are a diverse array of costs and benefits that are considered in the ESS Program, varying across dimensions such as which parties they accrue to, whether or not they are monetizable, and whether or not they affect electricity rates in Connecticut. Test perspectives help define a coherent set of costs and benefits to compare. For example, what are the net benefits of the program from the perspective of the Connecticut ratepayers (the Ratepayer Impact Measure or RIM) or society at large (the Societal Cost Test or SCT)?

The BCA includes a total of seven cost tests:

- Program Administrator Cost Test (PACT)
- Connecticut Efficiency Test (CTET)
- Participant Cost Test (PCT)
- Societal Cost Test (SCT)
- Total Resource Cost Test (TRC)
- Ratepayer Impact Measure (RIM)
- Connecticut Ratepayer Impact Measure (RIM-CT)

[20] See Connecticut Green Bank Order 7 Compliance filing in Docket No. 21-08-05: https://www.dpuc.state.ct.us/dockcurr.nsf/8e6fc37a54110e3e852576190052b64d/06045b22997703bc8525876400540604?OpenDocument

[21] See Program Administrators Orders 3 and 8 Compliance filings, including the previous Annual Report (Attachment 2) and the Excel model (Attachment 1): https://www.dpuc.state.ct.us/dockcurr.nsf/8e6fc37a54110e3e852576190052b64d/e8c1272ed4c4e9a585258cdc00487590?OpenDocument

The costs and benefits applicable to each of these tests are summarized in the table below. In last year's Annual Report, based on recurring themes in PURA interrogatories, the BCA was updated to include a seventh test, the RIM-CT. Historically, two tests have been given greater weight in the development of the program, namely the RIM and the Participant Cost Test (PCT).

The RIM is effectively a measure of costs and benefits associated with the ESS program that impact non-participants through changes in electricity rates. In its Final Decision in Docket No. 17-12-01RE03[22], PURA cites PA 21-53's objective for PURA to "provide positive net present value to all ratepayers, or a subset of ratepayers paying for the benefits that accrue to that subset of ratepayers" in setting a target RIM of 1.4 for the ESS Program.

A number of the benefits (particularly Demand Reduction Induced Price Effect or DRIPE benefits) yield benefits that would affect electricity prices for consumers across New England. Historically, the RIM has included benefits that would benefit ratepayers in Connecticut as well as other ISO-NE customers. In response to periodic requests from PURA to calculate the RIM excluding benefits that would accrue to ISO-NE customers outside of Connecticut (referred to as interstate or rest-of-pool benefits), [23] the BCA filed Docket No. 25-08-05 was updated to include a seventh test perspective, the RIM-CT, that excludes interstate benefits where the AESC provides values that can be differentiated by intrastate vs. interstate.

PURA and the Program Administrators also carefully consider the PCT, as it is intended to evaluate whether projects participating in the ESS Program are likely to yield net financial benefits to the participant. For example, in its Final Decision in Docket No. 23-08-05,[24] PURA's Order 23 directed the Program Administrators to file proposed upfront incentive levels for C&I projects in Tranches 2 and 3, such that "the commercial upfront incentive recommendation will achieve a PCT at or slightly above 1." Like all cost tests, PCT has limitations, including:

- The PCT does not replicate the more detailed financial analysis that would be undertaken by entities pursuing commercial projects.
- The PCT also varies significantly by project, based on characteristics such as customer segment (which affects incentive levels), ability to monetize federal tax credits, presence or absence of on-site distributed generation, rate class, load profile, and project-specific cost.
- The current ESS BCA evaluates projects over a 10-year project life; in reality, projects are likely to have both costs and benefits that extend beyond this 10-year term.

These limitations do not negate the value of considering the PCT; they are only mentioned to highlight what the PCT can and cannot reliably tell us and what that implies for how to apply interpretations of the PCT.

For this report, there are two changes to how costs and benefits are applied to different tests. First, the model has been updated to include projected clawbacks. These appear as a cost in the

[22] https://www.dpuc.state.ct.us/2nddockcurr.nsf/8e6fc37a54110e3e852576190052b64d/6991ef77ba07bae185258752007994f7?OpenDocument

[23] See, most recently, Interrogatory CAE-5 filed in Docket No. 25-08-05. https://www.dpuc.state.ct.us/dockcurr.nsf/8e6fc37a54110e3e852576190052b64d/36efe91c4b4230c385258cc00063db22?OpenDocument

[24] https://www.dpuc.state.ct.us/dockcurr.nsf/8e6fc37a54110e3e852576190052b64d/d7b4cb81bf3765ea85258a7600551890?OpenDocument

PCT, and a benefit in most other tests, as clawbacks effectively reduce the total amount of incentives paid out by the program.

Second, an adjustment has been made to how participant bill savings are treated. Previously, participant bill savings had been considered a benefit in the PCT and a cost in the RIM. Counting bill savings as a cost in the RIM is based on the understanding that the electric power system is effectively a fixed cost system[25] – to the extent that one customer pays less for service, that cost will have to be recovered from other customers. For delivery costs, which are largely based on revenue requirements established in rate cases, this assumption is largely valid, as under recovery will generally lead to increased rates. This same assumption likely does not apply to energy supply costs, as wholesale market costs are not tied to a "revenue requirement." Thus, the Participant Bill Savings impact is now separated into delivery charges vs. energy supply; both are benefits for the PCT, but only delivery charges are a cost in the RIM. All else being equal, this change marginally increases the RIM and leaves the PCT unchanged.

Table 5-1. BCA Cost Tests

Category	Benefit/Cost Stream	PACT	CTET	PCT	SCT	TRC	RIM	RIM-CT
Utility Benefits - Peak Savings	Avoided Generation Capacity	Benefit	Benefit	-	Benefit	Benefit	Benefit	Benefit
	Avoided T&D Capacity	Benefit	Benefit	-	Benefit	Benefit	Benefit	Benefit
	Reliability	Benefit	Benefit	-	Benefit	Benefit	Benefit	Benefit
	DRIPE Capacity Impacts	Benefit	Benefit	-	Benefit	Benefit	Benefit	Benefit*
Utility Benefits - Energy Savings	Avoided Energy	Benefit	Benefit	-	Benefit	Benefit	Benefit	Benefit
	DRIPE Energy Impacts	Benefit	Benefit	-	Benefit	Benefit	Benefit	Benefit*
	Cross-DRIPE Impacts	Benefit	Benefit	-	Benefit	Benefit	Benefit	Benefit*
Societal Benefits - GHG Savings	Non-Embedded Emissions	-	Benefit	-	Benefit	-	-	-
Program Administrative Costs	Program Administration	Cost	Cost	-	Cost	Cost	Cost	Cost
Participant Bill Savings	Participant Bill Savings	-	-	Benefit	-	-	Cost**	Cost**
Incentives	Program Incentives	Cost	Cost	Benefit	-	-	Cost	Cost
	Performance Incentive Aggregator Fee[1]	-	-	Cost	-	-	-	-
	Upfront incentive clawbacks	Benefit	Benefit	Cost	-	-	Benefit	Benefit
ESS Technology Costs	Participant Incremental DER Costs	-	-	Cost	Cost	Cost	-	-
Avoided Backup Generator	Net Avoided Backup Generator	-	-	Benefit	-	-	-	-

* Only benefits that accrue to Connecticut are included.

[25] Note that the BCA still accounts for net savings in other places, e.g., through avoided T&D capacity. Viewing participant bill savings as a cost in the RIM can be thought of as a pie of a fixed size, with participant bill savings increasing the size of the pie for non-participants. Other impacts (again, like avoided T&D capacity), can be thought of as reducing the total size of the pie.

**Participant bill savings pertaining to Transmission and Distribution services are included; Power Supply savings are not included.

[1]This represents fees charged by entities enabling the participation of resources in active dispatch events, taken out of the total payment delivered to the project owner. These costs are considered a cost in the PCT, and netted out of the incentive category.

Period Evaluated

The ESS BCA currently evaluates the life of projects installed through the inception of the program through 2027. Currently, in previous BCAs, this included a total of 300 MW of installed capacity; however, given historical and projected enrollments, this has been reduced to a total of 72 MW of installed capacity. This change in total modeled volume reduces the magnitude of costs and benefits included in the BCA. The BCA evaluates projects over a 10-year period; thus, the model currently evaluates costs and benefits through the end of 2036. As discussed in greater detail below, the model includes both historical data (e.g., participation data through winter 2025-2026) as well as projected values. As noted above, CES would expect that the life of most BESS installed through ESS would exceed 10 years; thus, this assumed project life may underestimate total programmatic benefits, both to ratepayers (affecting tests such as the RIM) and to project owners (affecting the PCT).

Note that CES anticipates expanding the BCA model to include CODs through 2030 in the next plan. This expansion would be facilitated by the availability of the 2027 Avoided Energy Supply cost study, as the 2024 study does not include values for resources with CODs through 2030.

5.2. Benefit-Cost Model Inputs

A review of key updated inputs and assumptions is provided below. Given the number of inputs embedded in the BCA, not every change has been identified, though those changes with substantive impacts have been identified. In general, the approach to updating assumptions has been to use evaluated data (that is, based on actual program data) when such data is available and reliable, make changes to projected inputs when there is a specific rationale for doing so (e.g., trends indicate a change is appropriate or a specific, exogenous change has occurred), and to otherwise retain assumptions used in previous rounds of BCA.

Evaluated Project Cost, Performance, and Incentive Inputs

CES updated the BCA model with evaluated data for project enrollment and performance through the Winter 2025-2026 Active dispatch season. Although the enrollment data used to inform assumptions in this section are the same as those presented in Section 3, the evaluated project cost assumptions are derived primarily from projects approved in 2025 and later. These projects better represent the current program characteristics and are therefore used to inform the updated project cost and evaluation metrics applied in this BCA. CES has also used its discretion in establishing the values, in some instances eliminating or reducing the weight of outliers.

Project Cost and Sizing. **Table 5-2** below shows the project sizes and costs reflected in the BCA model, applied to projected projects with a commercial operation date of 2026 or 2027. On a per kWh of installed capacity basis, these numbers have increased modestly from last year's evaluation. As illustrated in **Table 3-21**, average unit costs have generally decreased. Thus, the increase in assumed project costs reflects assumed project costs in the previous BCA that may have been slightly too low. The fluctuation in tariffs over the past 18 months has made projecting pricing for domestically-installed storage challenging. For commercial systems, the wide range of interconnection costs and other site-specific costs compounds the challenge in projecting

costs accurately. Given this uncertainty, the BCA model relies primarily upon cost data included in ESS applications for the BCA data, with an emphasis on the most recently approved and completed projects.

Table 5-2. Project Size and Cost Assumptions

Metric	Customer Segment			
	Residential	Small C&I	Medium C&I	Large C&I
Average Total System Cost per Participant ($)	$28,825	$472,076	$831,694	$1,594,200
Average System kW per Participant	15.3	200	500	1000
Average System kWh per Participant	25.25	460	1150	2900
Average Duration per Participant (hours)	1.65	2.30	2.30	2.90
Average $ per kWh (2026 Install Value)	$1,142	$1,026	$723	$550

***Source**: CES analysis of enrollment data*

Federal Tax Credits. Changes stemming from the 2025 federal budget reconciliation legislation enacted in 2025 are reflected in the BCA. Specifically, the bill phases out the Section 25D credit, under which residential customers qualified for a 30% tax credit for solar and energy storage installations. The credit was no longer available, starting with projects placed in service starting in 2026. Third party owned (TPO) residential systems may also benefit from the Section 48E credit; over time this may result in a shift towards more TPO residential systems. While residential third party ownership levels are still low, based on conversations with installers, the Program Administrators expect for third party ownership to increase over time. The BCA assumes that residential third party ownership rates (indicating eligibility for the 30% tax credit) will be 20% of projects installed in 2026, 40% in 2027 and 60% in 2028. The updated BCA assumes that, starting in 2026, no residential systems will be eligible for a 30% tax credit.

Commercial storage installations, which qualify under Section 48E, will still be eligible for a 30% federal tax credit; under current law, the credit won't begin to phase out until 2033. Foreign Entity of Concern (FEOC) provisions, which place limitations on project ownership interests and the amount of content that can be sourced from identified countries, including China, will challenge the ability of commercial projects to qualify for Section 48E credits. Based on its understanding of the market and discussions with developers, CES understands that many commercial projects will still qualify for Section 48E credits - given this, the BCA still assumes that C&I projects will be able to take advantage of Section 48E credits. While developers may struggle to meet FEOC provisions, these projects are less likely to proceed, supporting the assumption that most commercial projects benefit from the tax credit.

O&M. The BCA had previously assumed an O&M cost for both residential and C&I systems. Based on CES' understanding of the market, this value was reduced to $0 for residential systems starting in the BCA filed last year. For C&I systems, the model had previously assumed no O&M costs for

evaluated years (i.e., 2022 and 2023 in the previous version); this was also updated last year such that O&M costs apply to all operating C&I systems.

Construct 5 Updates. The BCA has been updated to reflect the transition to the Construct 5 program approved in the Final Decision in Docket No. 25-08-05.[26] Under the revised program design, only Legacy projects enrolled prior to April 1, 2026, remain eligible for upfront incentives, while projects enrolled on or after that date are eligible for Construct 5 Enrollment Incentives. Accordingly, the BCA assumes that upfront incentives apply only to the expected Legacy installations through the program transition, using the approved residential and C&I incentive schedules shown in **Table 5-3** and **Table 5-4**. This structure dispenses with the declining block incentive used for the Legacy upfront incentives. The BCA model also incorporates the updated performance incentives for Construct 5 systems. Effective April 1, 2026, the Construct 5 program replaces the Legacy Upfront Incentive with an Enrollment Incentive for newly enrolled projects.

The model requires adopting an assumption related to how much of the capacity installed in 2026 and 2027 will be Construct 5 vs. Legacy. For commercial systems, because there are no approved Construct 5 systems and because of the typical development timeline for these systems, it is assumed that no Construct 5 systems will be deployed by the end of 2027 (the last COD incorporated into the BCA model).

Table 5-3. Residential and C&I Legacy Upfront Incentive Levels ($/installed kWh)

Capacity Block (Cumulative MW)	Tranche, Step	Residential Standard	Residential Underserved	Residential Low Income
Up to 10 MW	Tranche 1, Step 1	$250	$450	$600
10-25 MW*	Tranche 1, Step 2	$212.5	$450	$600
Capacity Block (Cumulative MW)	**Tranche, Step**	**Small C&I**	**Medium C&I**	**Large C&I**
Up to 163.9 MW*	Tranches 1 and 2	$200	$175	$100

*Note: Upfront incentive values are shown only for the initial Legacy tranches, as future enrollments will be subject to Construct 5.

Table 5-4. Assumed Residential and C&I Enrollment Incentive Levels ($/installed kWh)

Framework	Residential - Grid Edge	Residential - Others	C&I - Priority	C&I - Others
Construct 5	$130	$30	$10	$0

Previous BCAs assumed that a portion of the upfront incentive dollars would be funded through Greenhouse Gas Reduction Funds (GHGRF). Starting in last year's report, the BCA was updated

[26] https://www.dpuc.state.ct.us/dockcurr.nsf/8e6fc37a54110e3e852576190052b64d/b1de90d5e52b43d185258d630056a8bf?OpenDocument

to assume that no GHGRF funding will become available, and that all incentive dollars are funded by ratepayers (thus, a cost in the RIM).

Upfront Incentive Clawbacks. Previous iterations of the BCA did not include projections for upfront incentive clawbacks. The current version has been updated to incorporate projected clawbacks; it assumes that in 2026, 40% of residential Legacy systems are subject to a clawback, falling to 35% in 2027. For commercial systems, it assumes 25% in 2026 and 20% in 2027. The model also assumes that, in addition to fewer systems being subject to any clawback over time, for those subjected to a clawback, the amount clawed back decreases over time as performance improves. Given the significant and rapid increase in Passive scoring in the program, these assumed improvements seem feasible. As noted above, clawbacks decrease the PCT, and increase most other tests, including the RIM.

Performance Incentive OEM Aggregator Fee. Two OEMs currently retain a portion of the residential performance incentives as a performance incentive aggregator fee. Specifically, Tesla charges a 20% fee and Franklin began charging a 10% fee starting with Summer 2025. Based on the current market share of these two providers and their fees, the BCA has been updated to assume that residential customers pay, on average, a 6% fee to OEMs. This is realized in the BCA as a reduction in the PCT; it does not affect other tests.

Peak Reduction. **Section 4** provides analysis of the performance of projects enrolled in the ESS Program. For prospective performance, the BCA calculates expected kW performance during active and Passive events, determined by:

- System power (kW)
- System energy (kWh)
- Percent of nameplate energy expected to be dispatched during passive and active events (%)
- The duration of passive and active events (hours)

These expected performance values are used to develop the "Max Expected Peak Reduction" values shown in **Table *5-5***, below, which, in turn, dictate how nameplate capacity in the BCA model translates into projected benefits.

For residential systems, the values are based on a combination of observed performance and expectations for how performance may evolve. Previous BCAs had assumed that residential systems would maintain a 50% backup reserve during both Active and Passive events; this was maintained in last year's BCA to provide consistency with previous analyses. Because systems did not, in practice, maintain such a large reserve, an assessment of performance based on this assumption yielded some expected reduction values that exceeded 100%. In this year's BCA, the residential reserve assumption has been updated to 20%, matching program guidance for passive events as well as the patterns observed in the telemetry data. Reducing the assumed backup value reduces the calculated performance values (as they are expected to have more kWh available to discharge). This updated reserve assumption yields an expectation that residential projects will deliver 80% of their maximum peak reduction during Passive events and 78% during Active events.

For C&I projects, the adopted Passive Max Expected Peak Reduction values are 90% for Small C&I and 60% for Medium and Large C&I projects, while the adopted Active Max Expected Peak Reduction values are 90% for Small C&I and 80% for Medium and Large C&I projects. These values are applied in the BCA to estimate expected peak demand reductions and the associated

program benefits. These values suggest that Medium and Large C&I projects have more competing needs for storage, including demand charge management.

In the BCA, Passive event performance is netted out of active event performance to avoid double-counting benefits.[27] As a result, Passive event performance is expected to increase (due to reduced event duration), while benefits attributed to the active program will decrease (as the larger Passive value will be netted out of measured active performance). Because the primary impact is to shift attribution from one event type to the other, the net impact on overall benefit cost ratios is negligible.

Table 5-5. Average System Max Expected Peak Reduction

	Residential Standard	Residential Underserved	Residential Low Income	Small C&I	Medium C&I	Large C&I
Expected Backup Reserve (Active and Passive)	20%	20%	20%	20%	20%	20%
Passive Max Expected Peak Reduction	80%	80%	80%	90%	60%	60%
Active Max Expected Peak Reduction	78%	78%	78%	90%	80%	80%

Note: See discussion above for source of these values.
Source: *CES analysis of interval data*

Program Deployment Targets. In its Final Decision in Docket No. 24-08-04,[28] PURA ordered the reallocation of 140 MW of capacity from the residential projects to C&I, yielding the updated MW allocation illustrated in **Table 5-6** below. Effective April 1, 2026, any remaining legacy Tranche capacity is reassigned to Construct 5.

Table 5-6. Program Deployment Targets (MW)

Customer Class	Tranche 1	Tranche 2	Tranche 3	Tranche 4	TOTAL
Residential	50 MW	50 MW	50 MW	0 MW	150 MW
Commercial	50 MW	113.9 MW	126.1 MW	140 MW	430 MW
Total*	**100 MW**	**163.9 MW**	**176.1 MW**	**140 MW**	**580 MW**

*Note: On April 1, 2026, any remaining Tranche capacity will be reassigned to Construct 5.

The BCA evaluates projects with commercial operation dates through the end of 2027, totaling 71.7 MW; as noted above, this is a decrease from the 300 MW that had previously been modeled

[27] For example, if a single system averaged a 5-kW peak reduction during active events and 3 kW during Passive events, the BCA would attribute a 2-kW reduction to the active events.

[28] https://www.dpuc.state.ct.us/dockcurr.nsf/8e6fc37a54110e3e852576190052b64d/5dfd10f7c319dfec85258be90050bf9c/$FILE/240805-120424.pdf

to come online during this period.[29] The updated projections total 72 MW of installed capacity by 2027. Aside from exceptions discussed below, other assumptions related to project deployment (e.g., assumption that 80% of projects will be in Eversource territory), remain unchanged.

Table 5-7. Projected Program Enrollment (MW)

Customer Type	2022	2023	2024	2025	2026	2027	Total
	Actual	Actual	Actual	Actual	Forecast	Forecast	
Residential Standard	0.1	0.8	1.3	1.6	6.3	7.2	17.2
Residential Underserved	0.0	0.1	0.7	0.8	3.2	3.6	8.3
Residential Low Income	0.0	0.0	0.2	0.3	1.1	1.2	2.8
Residential Subtotal	0.1	0.9	2.2	2.7	10.5	12.0	28.3
Small C&I	0.0	0.0	0.2	0.0	4.2	6.0	10.4
Medium C&I	0.0	0.0	0.2	0.0	5.3	7.6	13.2
Large C&I	0.0	0.0	0.3	0.0	8.0	11.4	19.8
C&I Subtotal	0.0	0.1	0.6	0.0	17.6	25.0	43.4
Total	0.1	1.0	2.8	2.7	28.1	37.0	71.7

*It is assumed that 25% of residential ESS capacity installed in 2026 and 75% installed in 2027 will fall under Construct 5, with the remaining installations under the Legacy framework.

Should the program fall short of projected MW goals, it will reduce both projected costs and benefits. Two primary factors will affect the resulting BCRs. First, fewer total installed MWs applied to fixed Program Administrative Costs will lead to higher per MW costs, reducing the RIM. Second, some levelized benefits streams (particularly capacity DRIPE) in the AESC can vary noticeably from one assumed COD to the next, which can lead to changes in resulting BCRs.

Program Administration Costs

The BCA model was updated with program costs for the year 2025. Program costs in the year 2025 were lower than had been projected in the BCA ($4.29 million projected vs. $2.38 million actual). Projected program administration costs for 2026 and later have been updated, based on feedback from the Program Administrators. Because the total MW included in the model was reduced, the approach to assigning program administration costs to different project vintages was updated; in essence, the model was updated to acknowledge that the program administration costs reflected in the table below would cover costs for the full program MW (i.e., up to 580 MW), while only a total of 72 MW of resources is included in the model, assigning administration costs on a pro-rata basis.

[29] The model evaluates the costs and benefits of these projects for a period of 10 years from their commercial operation date.

Table 5-8. Actual (through 2025) and Projected Program Administration Costs ($)

Project Year	Residential			C&I		
	Upfront/Passive	Performance/Active		Upfront/Passive	Performance/Active	
	Connecticut Green Bank	Eversource	UI	Connecticut Green Bank	Eversource	UI
2022	$1,521,716	$124,658	$268,589	$0	$0	$0
2023	$1,478,092	$201,878	$176,545	$31,665	$205,138	$117,696
2024	$785,357	$261,965	$174,233	$785,357	$261,965	$174,233
2025	$828,740	$192,994	$166,893	$828,740	$192,994	$166,893
2026	$857,746	$202,237	$173,800	$857,746	$202,237	$173,800
2027	$887,767	$405,887	$181,010	$887,767	$405,887	$181,010
2028	$918,839	$456,806	$190,631	$918,839	$456,806	$190,631
2029	$950,998	$501,632	$201,956	$950,998	$501,632	$201,956
2030	$984,283	$543,565	$215,279	$984,283	$543,565	$215,279
2031	$556,226	$393,143	$152,683	$1,117,055	$789,539	$306,629
2032	$459,343	$330,164	$133,820	$1,213,939	$872,549	$353,657
2033	$457,612	$338,787	$140,715	$1,215,670	$900,007	$373,816
2034	$453,499	$345,815	$145,436	$1,219,783	$930,143	$391,181
2035	$447,734	$351,661	$148,829	$1,225,547	$962,576	$407,377
2036	$438,587	$354,811	$150,162	$1,234,694	$998,853	$422,730
2037	$431,009	$359,142	$151,031	$1,242,272	$1,035,132	$435,308

***Notes*:** Evaluated and projected values provided by Program Administrators. Projected values are subject to change.

Source: *Program Administrators*

Benefits Inputs

Most assumptions related to avoided costs and other benefits used in the BCA are derived from the Avoided Energy Supply Costs in New England (AESC) studies, which are commissioned by utilities, regulators, state energy offices, and other entities across New England, specifically for use in BCAs. Consistent with previous ESS BCAs, the BCA applies values from the 2021 AESC to projects with commercial operation dates of 2022-2024 and applies the 2024 AESC values to projects with commercial operation dates of 2025-2027.[30]

For the values sourced from the 2024 AESC, BCA results are provided using both Counterfactuals #1 and #6.[31] The same approach was taken in the BCA filed in Docket No. 24-08-05.[32] In its Final Decision in that docket, PURA, concluding that shifting to a new counterfactual would be

[30] As the 2024 AESC can be applied to projects with CODs in 2024, subsequent BCAs may be updated to apply 2024 AESC values to these projects, as opposed to sourcing inputs from the 2021 AESC.

[31]The AESC counterfactuals are defined by whether they include the effects of different anticipated changes to the distribution system (e.g., increased energy efficiency, building electrification, BTM storage, transportation electrification, etc.). By excluding these different influences, the counterfactuals help estimate what the impact of a program might be, relative to a future in which such programs did not exist. Counterfactual #1 excludes impacts from most energy policies (e.g., energy efficiency, building electrification, demand response, etc.). Counterfactual #6 only excludes BTM storage, making it well-suited for evaluating BTM storage programs. See Table 40 on p. 73 of the 2024 AESC: https://www.synapse-energy.com/sites/default/files/inline-images/AESC%202024%20May%202024.pdf

[32]https://www.dpuc.state.ct.us/dockcurr.nsf/8e6fc37a54110e3e852576190052b64d/ddbe0b811039ecbc85258b6c006b2d61?OpenDocument

disruptive to consistent analysis of the program, ordered that future BCAs should rely on AESC Counterfactual #1, while allowing the Program Administrators to "include alternative RIM calculations using new counterfactuals… provided that counterfactual one remains the primary basis for RIM scores submitted to the Authority." [33] CES has included selected results using Counterfactual #6, as this counterfactual was designed for use in evaluating BTM storage programs. As briefly noted above, depending on the timing of the study, next year's BCA may incorporate updated AESC assumptions from the 2027 study.

Table 5-9. Benefits Inputs Sources

Benefit/Cost Stream	Source	
	2022-2024 Install Yr	2025 and future Install Yr
Avoided Generation Capacity **DRIPE Capacity Impacts (Intrastate and Rest-of-Pool)** **Avoided Energy** **DRIPE Energy Impacts (Intrastate and Rest-of-Pool)** **Cross-DRIPE Impacts (Intrastate and Rest-of-Pool)** **Avoided Pool Transmission Facilities** **Reliability** **Non-Embedded Emissions**	• *2021 AESC* • *Report and User Interfaces (source of values) available here: Link* • *Counterfactual #1* • *State set to Connecticut; otherwise default inputs used*	• *2024 AESC* • *Report and User Interfaces (source of values) available here: Link* • *Counterfactuals #1 and #6* • *State set to Connecticut; otherwise default inputs used*
Avoided Local Transmission Capacity **Avoided Distribution Capacity**	• Per Eversource and UI, and as incorporated into the filed 2025-2027 Conservation & Load Management Plan (see figure 62): Link	

5.3. BCA Metrics

Results from the BCA, including six different test perspectives, are provided below. Unless otherwise specified, the results are based on the use of the AESC 2024 Counterfactual #1

Figure *5-1* shows the overall program BCA. The PACT, SCT, TRC, and CTET have effectively identical benefits. The PACT and CTET have lower costs than the SCT and TRC, resulting in higher benefit-cost ratios (BCRs). The primary costs for the PACT and CTET are incentives, while the primary costs for the SCT and TRC are ESS technology costs. Technology costs are almost all realized in the year projects are installed, while performance incentives are spaced out over time and are then discounted; this is the primary reason that costs for these two sets of tests differ. The CTET includes emissions, while the PACT does not. The BCA currently projects an increase in emissions due to ESS; this varies from the finding in **Table 4-11** for several reasons, including:

1) **Table 4-11** uses hourly emissions rates while the BCA uses seasonal and on/off-peak emissions rates, which are less granular

[33] P. 46: https://www.dpuc.state.ct.us/dockcurr.nsf/8e6fc37a54110e3e852576190052b64d/5dfd10f7c319dfec85258be90050bf9c?OpenDocument

2) Most of the BCA charge/discharge behavior is projected (not evaluated), while **Table 4-11** relies entirely upon evaluated charge/discharge data; there are differences in the shape of the projected and evaluated load shape
3) **Table 4-11** is limited to one year of data, while the BCA considers emissions rates projected into the future

The overall program RIM has decreased modestly relative to the last BCA, from 1.69 to 1.55. The primary drivers of this change are:

1) Decreased projected MW deployment increasing per unit program administration costs, primarily in the near term (decreases RIM)
2) Decreased program administration costs (increases RIM)
3) Increase in projected performance, as described in **Table 5-5** (small increase in RIM)
4) Change in when projects are projected to come online (mixed impact – affects costs and benefits)
5) Introduction of assumed clawbacks (increases RIM)

The impact of some of these changes, and others, are discussed below.

The most significant contributor to the revised BCA results is the reduction in projected ESS deployment from approximately 300 MW to 72 MW by 2027. Since nearly all benefit streams—including participant bill savings, avoided capacity costs, energy savings, emissions reductions, and resilience benefits—are proportional to the deployed storage capacity, the lower deployment forecast substantially reduces total program benefits. As noted above, this decreases the RIM; it has a much more dramatic impact on the magnitude of costs and benefits, however.

The introduction of the Construct 5 framework and revisions to the assumed participation of Priority and Grid-Edge customers have only a marginal influence on the BCA results. Construct 5 contributes only 9 MW of residential installations through 2027, representing a relatively small share of the total program deployment. Likewise, reducing the assumed participation of Grid-Edge and Priority customers from 50% to 48% and 43%, respectively, slightly modifies the incentive expenditures and associated benefits but does not materially alter the overall program economics.

The revised analysis also incorporates lower program administrative costs, which improves the benefit-cost performance from the utility and societal perspectives. Since administrative expenses are treated as program costs in tests such as RIM, RIM-CT, PACT, CTET, SCT, and TRC, reducing these costs lowers the denominator of the benefit-cost calculations, resulting in modest improvements ranging from approximately 5–7%. In contrast, the Participant Cost Test (PCT) remains unaffected because program administrative expenditures are not borne directly by participating customers and therefore have no direct influence on participant economics.

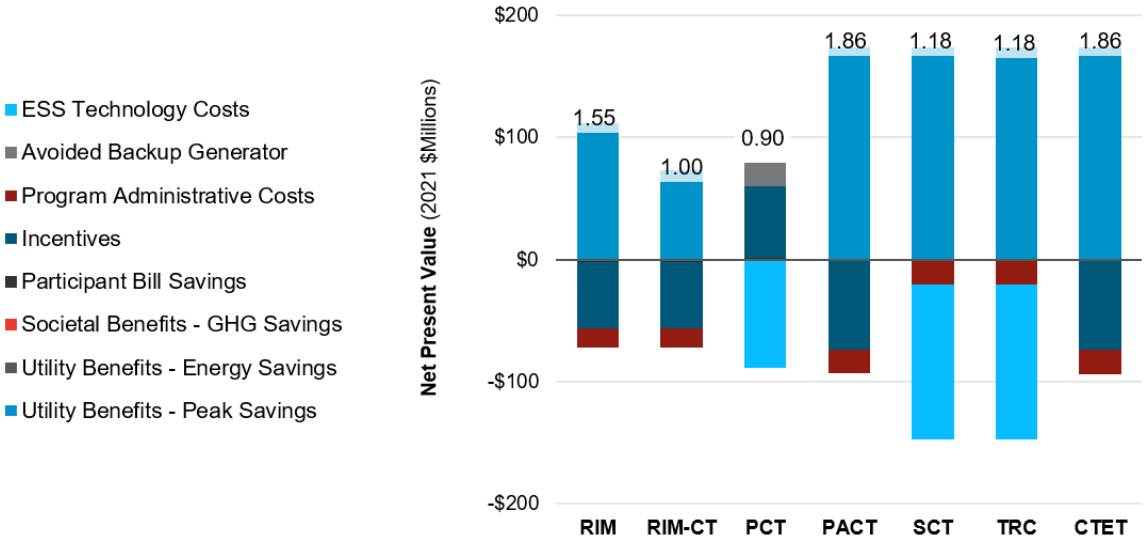
Conversely, the updated installed project costs relative to previous assumptions increase the capital investment required for ESS deployment, particularly within the C&I sector. Higher installed costs directly increase participant expenditures and total resource costs, leading to reductions in the PCT, SCT, and TRC. The PCT is especially sensitive because it evaluates the financial attractiveness of the program from the participant's perspective, while the SCT and TRC incorporate the total societal and resource costs associated with ESS deployment. Since these higher capital costs are not accompanied by proportional increases in program benefits, the overall cost-effectiveness under these tests decreases. While changes in projected installed cost do not directly affect the RIM, to the extent that they affect program deployment and lead to

changes in incentive rates, they may have future impacts on the RIM. As noted previously, these updated cost values do not reflect an anticipated increase in project costs in the future; instead, they reflect project costs anticipated to be higher than previously projected. Put differently, assumed project costs reflected in the previous BCA were likely too low.

For residential systems, the revised assumptions related to third-party ownership rates and resulting access to the Section 48E tax credits improves the calculated PCT by approximately 5%. The BCA does not currently include differentiated assumptions related to discount rate, administration costs, or other financial distinctions between third-party vs. homeowner-owned systems. It is reasonable to assume that a third party owner would "capture" some of the value of the tax credit, reducing the impact of the credit on the ultimate financial proposition for the host customer.

When all model revisions are considered collectively—including the updated deployment forecasts, Construct 5 implementation, participant mix, installed project costs, administrative cost assumptions, clawback revisions, updated peak active and passive load reduction metrics and additional structural enhancements to the BCA framework—the overall cost-effectiveness metrics decline modestly relative to the previous analysis. The RIM decreases by approximately 9%, PCT decreases by around 6%, PACT and CTET decline by approximately 8%, while the SCT and TRC exhibit the largest reductions of approximately 13%. Although reductions in administrative costs partially offset some of these impacts, the lower projected deployment and higher installed project costs remain the dominant factors influencing the revised BCA results.

Figure 5-1. Overall Program BCA



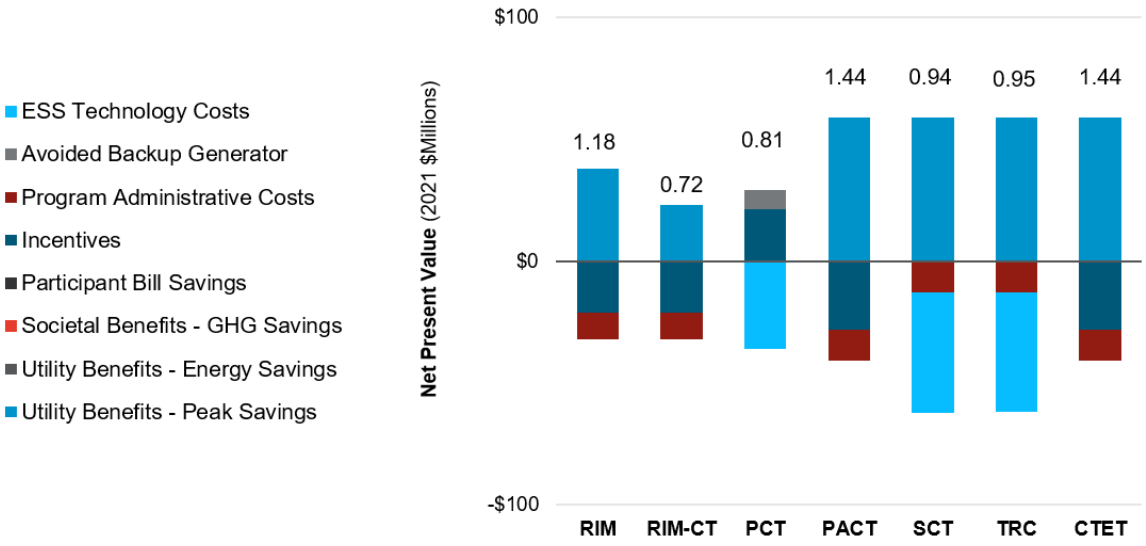
Source: *CES analysis*

Figure 5-2 shows the BCA specifically for the residential sector. The updated residential BCA shows modest improvement across all tests: the RIM rises from 1.13 to 1.18, the PCT rises from 0.75 to 0.81, the PACT increases from 1.36 to 1.44, the SCT and TRC both improve from 0.88 to 0.94 and .095 respectively, and the CTET rises from 1.36 to 1.44.

Most of this improvement is driven by a reduction in the residential battery reserve margin, from 50% to 20%, which increases the battery capacity available for dispatch and, with installed costs held constant, directly increases realized program benefits, improving the RIM and RIM-CT by

roughly 17–20%, the PACT, CTET, SCT, and TRC by over 15%, and the PCT by about 10%.[34] While a reduction in total program costs helps cost-effectiveness, a shift in how costs are weighted between residential and commercial projects results in more costs being allocated to residential projects relative to commercial projects. It is projected that approximately 9 MW of residential ESS installations will be installed under Construct 5 by the end of 2027; previously, all of this capacity would have been under the Legacy framework. This has a comparatively modest effect, improving the RIM and RIM-CT by about 2% and the PCT and SCT by about 1%. This is by design – PURA, in revising enrollment and performance incentives for Construct 5, explicitly sought to ensure that overall compensation remained comparable.

Figure 5-2. Residential Program BCA



Source: *CES analysis*

The C&I BCA results generally mirror the changes observed in the overall BCA, with the revised assumptions producing similar trends across the various benefit-cost tests. Commercial BCA results are displayed in **Figure 5-3**. For the commercial systems, the evaluated installed ESS project costs, derived from projects approved from 2025 onward, are the primary driver of the revised BCA results. Relative to the previous assumptions, the approximately 18% increase in assumed installed project cost per kWh increases participant and program costs without a corresponding increase in quantified benefits, reducing the PCT by approximately 8% and the SCT and TRC by 14–15%. Smaller reductions (5-6%) are observed in the RIM, PACT, and CTET tests.

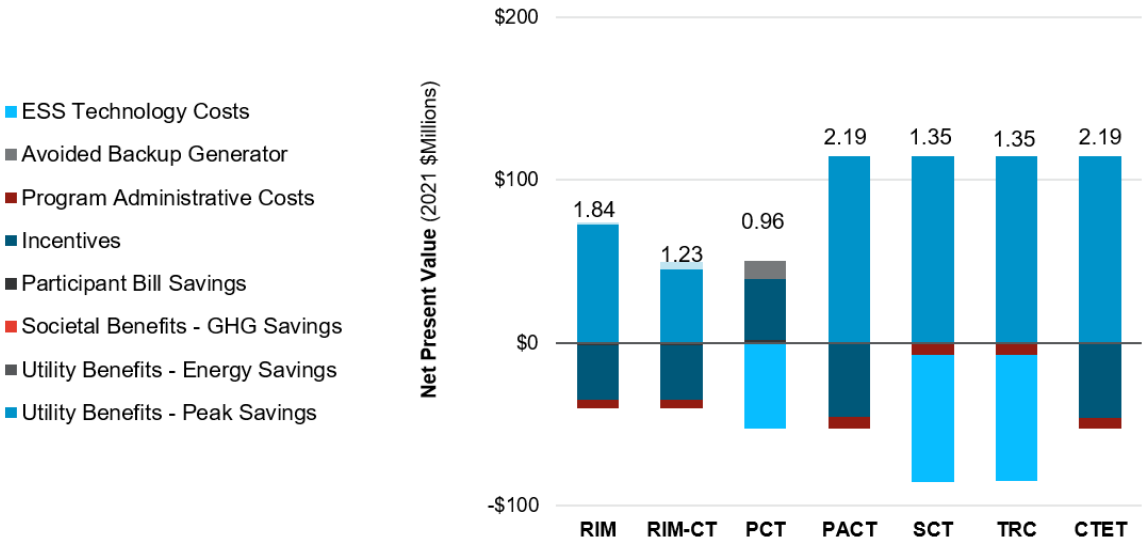
The updated program administration costs partially offset these impacts, as lower projected administrative expenditures reduce overall program costs and improve most BCA metrics. Similarly, the revised clawback assumptions result in modest improvements of approximately 2% in the RIM, PACT, and CTET tests, while having minimal influence on the remaining metrics.

The remaining updates—including revised historical program performance and administrative data through 2025, updated dispatch assumptions, Priority C&I participation assumptions based on the project enrolment so far, updated energy and delivery tariffs, and other refinements to the BCA framework—collectively contribute to the overall reduction in the commercial cost-

[34] Note that a part of this increase in performance is offset in the "Max Expected" values, as shown in **Table 5-5**.

effectiveness metrics. Despite the partially offsetting effect of lower program administration costs, the higher evaluated installed project costs remain the dominant factor influencing the revised non-residential BCA results.

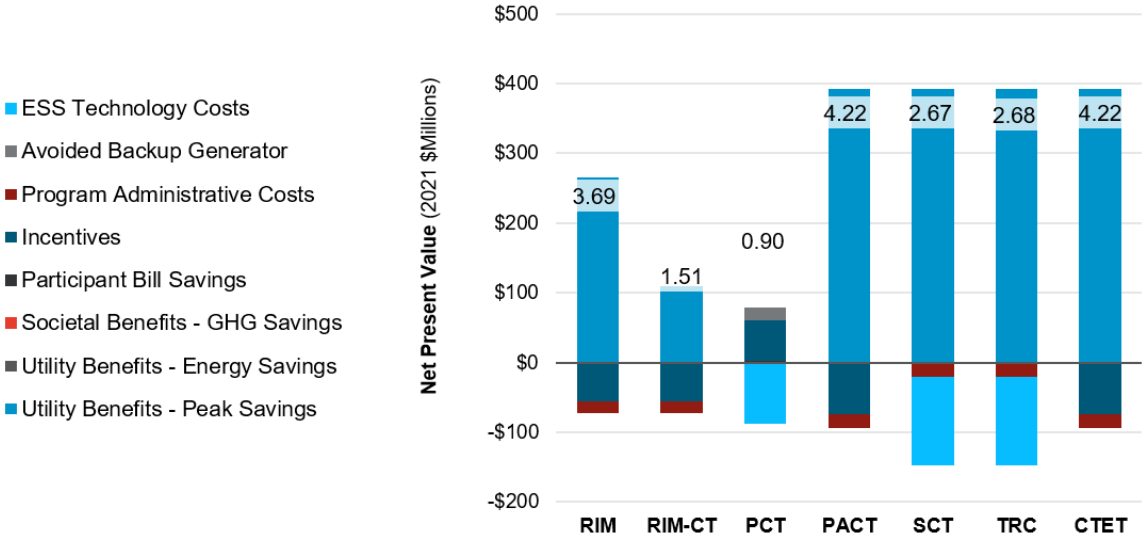
Figure 5-3. C&I Program BCA



Source: *CES analysis*

Finally, the full program BCA conducted using AESC 2024 Counterfactual #6 is provided in **Figure 5-4**. The use of Counterfactual #6 dramatically increases all tests except for the PCT. To the extent that the Program Administrators determine that currently planned incentive levels are insufficient to achieve program deployment goals, these results demonstrate that there would be the opportunity to increase incentive levels while maintaining a robustly cost-effective program, using a counterfactual designed for evaluating behind-the-meter storage programs.

Figure 5-4. Overall Program BCA - AESC Counterfactual 6



Source: *CES analysis*

5.4. Findings and Recommendations

Table 5-10. BCA Findings and Recommendations

Finding	Recommendation
The ability of residential customers to benefit from federal tax incentives through third-party ownership has a substantial impact on the economics of these projects.	The Program Administrators should continue to monitor the level of third-party ownership in residential systems and, to the extent practical, evaluate the comparative economics of third-party- and homeowner-owned systems.
The AESC Counterfactual 6 likely represents a more appropriate counterfactual for evaluating the ESS Program.	PURA's direction to continue to use Counterfactual 1 was based on a desire to maintain some consistency in how the program is evaluated; given that there are likely to be significant changes in the forthcoming 2027 AESC, it may be appropriate to switch to a counterfactual designed for evaluating distributed storage when the 2027 AESC is adopted in the ESS BCA.

Source: *CES analysis*

3. Key Findings and Recommendations

Below, CES provides key findings and recommendations, based on metrics compiled for this report and CES' overall review of the program.

6.1. Key Findings

The program continues to evolve with the implementation of Construct 5. As the program nears the end of its second three-year cycle, reevaluating higher-level goals may be appropriate.

Key findings include:

- The Program Administrators have worked diligently to improve the quality of telemetry data. While further improvements should still be made, the process has made real-time performance monitoring and evaluation more efficient and effective.
- The Program Administrators have also worked with OEMs to substantially improve residential performance. The data suggest that, because performance is largely dictated by how OEMs respond to program dispatch signals, improving the performance of individual OEMs with substantial numbers of enrolled systems can meaningfully improve the performance of the program as a whole.
- Despite improvements, there continue to be data quality challenges, both for enrollment and telemetry data. There are also data gaps in enrollment data, created primarily by customer self-enrollment.
- Program deployment continues to be slow relative to the goal of 580 MW by 2030. Revisiting the feasibility of achieving this target will help focus the program on achieving realistic goals.
- The commercial project pipeline is stymied both by a dearth of new applications as well as the slow pace of approved projects achieving commercial operation.
- Relative to last year, the tariff landscape, and its impact on energy storage costs, has calmed somewhat. Residential project unit costs appear to be declining, while commercial projects do not exhibit the same pattern.
- The program is falling short of the target of 40% participation by residential Low-Income and Underserved participants. A single affordable multifamily project makes up a significant portion of the overall volume of Low-Income participants.

6.2. Recommendations

- Because performance by OEM varies substantially, the Program Administrators should continue to seek opportunities to address poor performing OEMs. Increased transparency and data availability on the ESS dashboard are a positive step. The PAs should examine additional strategies, including continuing to work with the OEMs themselves, increasing information on the relative performance of OEMs for potential ESS participants, and considering proposing incentives or penalties for OEMs that perform poorly consistently. Of course, the Program Administrators must also consider the effort and cost of prolonged engagement with OEMs serving a very low volume of customers.
- Along these lines, the PAs should also consider whether DERMS providers can and should play a more prominent role in identifying performance challenges and working with OEMs to address them. DERMS providers work with OEMs across programs and states; this should create an opportunity for efficient monitoring and engagement around performance. The Program Administrators may even consider introducing performance mechanisms that encourage DERMS providers to more actively engage with OEMs, although careful consideration must be given to ensure that this would not provide a perverse incentive to report improved performance.

- The Program Administrators should improve the process for addressing data gaps associated with customers transferring from ConnectedSolutions and/or self-enrolling customers. This could include finding ways to source the missing data (which may mean placing additional requirements around the self-enrollment process) or, as an alternative, ensuring a clear process for addressing how missing fields are populated in the enrollment database.
- In the next year's annual review (which will include the three-year evaluation), there should be a deliberate conversation related to the feasibility of achieving the program's 580 MW by 2030 goal. This should include consideration of the impact of Construct 5 on program enrollment, evolving project costs and resulting customer economics, and the role of other resource types (such as electric vehicles discharging energy to the grid).
- Relatedly, the Program Administrators should provide an assessment of whether achieving the 40% Low-Income and Underserved participation rate is achievable. If they determine that it may not be achievable, they should identify specific barriers. If they find that it is achievable, they should outline what implementation steps will be taken to increase participation rates, as the status quo is highly unlikely to lead to achieving the target. This analysis should also consider the root cause(s) of higher unit costs for Low-Income and Underserved projects.
- The overall success of the program, on a MW achievement basis, hinges largely upon the commercial sector. The Program Administrators should consider engaging in a structured process for evaluating barriers to new applications and the completion of approved projects. Recommendations for changes to incentive levels may also be warranted. As a part of this, the Program Administrators should evaluate whether there are any emerging trends in commercial project costs that indicate where the sector may be headed.
- The success of the ESS program is tied to developments outside of the program itself. These include:
    - The design of TOU rates and the availability of advanced meters for Eversource customers.
    - Interactions between ESS and distributed generation incentive policies; CES understands that the solar successor programs are likely to incorporate a differentiated value for exported solar, which could support storage deployment.
    - Continued improvements to the interconnection process; the EDCs and other stakeholders have been involved in a sustained process to make improvements, but further improvements, or at least an understanding of remaining barriers, should be prioritized.