STATE OF CONNECTICUT

PUBLIC UTILITIES REGULATORY AUTHORITY
TEN FRANKLIN SQUARE
NEW BRITAIN, CT 06051

DOCKET NO. 26-08-05 ANNUAL ENERGY STORAGE SOLUTIONS PROGRAM REVIEW – YEAR 6

October 29, 2026

PROPOSED DECISION

This proposed Decision is being distributed to the participants in this proceeding for comment. The proposed Decision is not final. The Authority will consider the participants' arguments and exceptions before reaching a final Decision, which may differ from the proposed Decision. Therefore, this proposed Decision does not establish any precedent and does not necessarily represent the Authority's final conclusion.

TABLE OF CONTENTS

I. INTRODUCTION 1

A. SUMMARY 1
B. BACKGROUND OF THE PROCEEDING 1
C. CONDUCT OF THE PROCEEDING 2
D. PARTIES AND INTERVENORS OR PARTICIPANTS 2

II. LEGAL AUTHORITY 3

III. PROGRAM OBJECTIVES 3

IV. AUTHORITY ANALYSIS 4

A. PROGRAM OVERVIEW 4
B. BIDIRECTIONAL EV PARTICIPATION 7
1. Background 7
2. Stakeholder Comments 8
3. Authority Analysis 12
C. ENROLLMENT INCENTIVE CLAWBACK 23
1. Background 23
2. Stakeholder Comments 25
3. Authority Analysis 28
D. FTM STORAGE TARIFF 31
1. Background 31
2. Stakeholder Comments 32
3. Authority Analysis 36
E. DATA DASHBOARD 42
1. Background 42
2. Authority Analysis 43
F. PROGRAM REDLINE AND RECOMMENDED CHANGES 43
1. Performance Payment Frequency 44
2. Change Orders 45
3. Insurance Requirements 47
4. Add-on Storage 47
5. Telemetry Data Audits 49
6. Miscellaneous 51
7. Updated Documents 51

V. CONCLUSION AND ORDERS 52

A. CONCLUSION 52
B. EXISTING AND NEW ORDERS 52
1. Standing Orders to be filed in ESS Annual Review Dockets 52
2. New Orders 57

PROPOSED DECISION

I. INTRODUCTION

A. SUMMARY

The Public Utilities Regulatory Authority (Authority or PURA) approves updates to the Energy Storage Solutions Program (ESS Program or Program), administered by The Connecticut Light and Power Company d/b/a Eversource Energy (Eversource), The United Illuminating Company (UI; collectively, with Eversource, the electric distribution companies or EDCs), and the Connecticut Green Bank (CGB; collectively, with the EDCs, the Program Administrators). The approved changes are intended to better align the ESS Program with the Program's objectives.

B. BACKGROUND OF THE PROCEEDING

On July 28, 2021, the Authority issued its Final Decision in Docket No. 17-12-03RE03, PURA Investigation into Distribution System Planning of the Electric Distribution Companies – Electric Storage (Storage Decision) establishing a nine-year program to support electric storage in Connecticut, starting on January 1, 2022, and continuing through December 31, 2030, pursuant to Public Act No. 21-53 (PA 21-53) and Conn. Gen. Stat. §§ 16-11, 16-19, 16-19e, and 16-244i, and in accordance with the October 2, 2019 Interim Decision in Docket No. 17-12-03, PURA Investigation into Distribution System Planning of the Electric Distribution Companies (Equitable Modern Grid Decision). Public Act No. 26-127 § 6(a) subsequently extended the ESS Program through December 31, 2035, to align with Connecticut's successor solar programs.

The Authority annually reviews key ESS Program metrics, including deployed megawatts (MW), and makes strategic adjustments as necessary to support the Program's objectives. Storage Decision, p. 43. Additionally, during the last year of each three-year Program cycle (e.g., 2024), "the Authority will conduct a full program review . . . including an evaluation of the existing program design to ensure that the Program is: (1) delivering on the expected value to Connecticut's ratepayers; and (2) is meeting the Program Objectives." Id., p. 44.

The Authority conducted the first annual ESS Program review in Docket No. 21-08-05, Annual Review of the Electric Storage Program – Year 1, issuing a Decision on December 8, 2021 (Year 1 Decision). The Decision reviewed the Year 1 Program design documents and other key compliance filings, and addressed other topics regarding Program implementation, to successfully execute the first year of the ESS Program beginning January 1, 2022.

Additionally, the Authority conducted the second annual ESS Program review in Docket No. 22-08-05, Annual Energy Storage Solutions Program Review – Year 2, and issued a Decision on December 21, 2022 (Year 2 Decision). The Year 2 Decision

reviewed Year 1 deployment data and introduced several modifications to better align the Program with its objectives.

The Authority conducted the third annual ESS Program review in Docket No. 23-08-05, Annual Energy Storage Solutions Program Review – Year 3, and issued a Decision on November 29, 2023 (Year 3 Decision). The Year 3 Decision assessed Year 2 deployment data and approved additional changes to further enhance the Program's alignment with its goals.

The Authority conducted the fourth annual ESS Program review in Docket No. 24-08-05, Annual Energy Storage Solutions Program Review – Year 4, and issued a Decision on December 4, 2024 (Year 4 Decision). The Year 4 Decision reviewed Year 3 deployment data and adopted further adjustments to improve alignment with Program's objectives.

Most recently, the Authority conducted the fifth annual ESS Program review in Docket No. 25-08-05, Annual Energy Storage Solutions Program Review – Year 5, and issued a Decision on December 17, 2025 (Year 5 Decision). The Year 5 Decision reviewed Year 4 deployment data and modified the Program's compensation structure to place greater emphasis on performance-based incentives.

C. CONDUCT OF THE PROCEEDING

On March 26, 2026, the Authority issued the Notice of Proceeding in the above-captioned docket.

On June 16, 2026, the Authority issued a Notice of Request for Written Comments on the following topics: (1) enrollment incentive clawback; and (2) front-of-the-meter (FTM) storage tariff. The Authority received eight sets of written comments from interested stakeholders on July 9, 2026.

On August 7, 2026, the Authority held a Technical Meeting to discuss the topics outlined in the June 16, 2026 Notice of Request for Written Comments.

On August 12, 2026, the Authority issued a second Notice of Request for Written Comments on the following topics: (1) recommended programmatic changes; and (2) bidirectional electric vehicle (EV) participation. The Authority received nine sets of written comments from interested stakeholders on or before August 28, 2026.

On September 3, 2026, the Authority held a second Technical Meeting to discuss the topics outlined in the August 12, 2026 Notice of Request for Written Comments.

On October 29, 2026, the Authority issued a Proposed Final Decision and provided an opportunity for docket Participants to file written exceptions.

D. PARTIES AND INTERVENORS OR PARTICIPANTS

A listing of all Participants to this proceeding is appended hereto as Appendix A.

II. LEGAL AUTHORITY

The Authority was directed to "develop and implement one or more programs, and associated funding mechanisms, for electric storage resources connected to the electric distribution system." General Statutes § 16-243ee (a). Pursuant to General Statutes §§ 16-243ee, 16-11, 16-19, 16-19e, and 16-244i (see Section II of the Storage Decision), the Authority established the Program through the Storage Decision. Furthermore, the Authority is permitted to select CGB, the Department of Energy and Environmental Protection (DEEP), the EDCs, a third party, or any combination thereof to implement and/or administer the Program. General Statutes § 16-243ee(d).

The Authority indicated in the Storage Decision that it will initiate an annual docket to review key ESS Program metrics, to ensure that the Program is on track to meet its deployment targets. Storage Decision, p. 43. Herein, the Authority reviews the Program documents developed by the Program Administrators, relevant compliance filings, and current incentive rates to determine if and how the ESS Program should be modified to better align with the direction provided in the Storage Decision.

III. PROGRAM OBJECTIVES

In the Storage Decision, the Authority adopted the following seven objectives (Program Objectives) to guide the Program Administrators in the development and implementation of the Program:

1) Provide positive net present value to all ratepayers, or a subset of ratepayers paying for the benefits that accrue to that subset of ratepayers.
2) Provide multiple types of benefits to the electric grid, including, but not limited to, customer, local, or community resilience, ancillary services, peak shaving, and avoiding or deferring distribution system upgrades or supporting the deployment of other distributed energy resources.
3) Foster the sustained, orderly development of a state-based electric energy storage industry.
4) Prioritize delivering increased resilience to: (1) low- to moderate-income (LMI) customers, customers in environmental justice or economically distressed communities, customers coded for medical protection, and public housing authorities as defined in General Statutes § 8-39(b); (2) customers on the grid-edge who consistently experience more and/or longer than average outages during major storms; and (3) critical facilities as defined in General Statutes § 16-243y(a)(2).
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 by reducing emissions associated with fossil-based peaking generation.
7) Maximize the benefits to ratepayers derived from the wholesale capacity market.

Storage Decision, pp. 5–7. Accordingly, the Authority relied on the Program Objectives to guide its review of the Program Administrators' compliance filings and in evaluating the current ESS Program design and assessing any possible changes to be ordered in this proceeding. The primary objective of the Authority's review was to better align the ESS Program with the Program Objectives and the direction provided in the Storage Decision. "Key Annual Review filings shall be submitted on or around August 1st . . . including, but not limited to: an annual report, including Program results and recommendations for Program modifications as discussed in Section V.F." Storage Decision, p. 43.

The Authority reaffirms that the above-listed Program Objectives shall guide the Program Administrators in their administration of the ESS Program, particularly in instances not explicitly addressed through the approved ESS Program documents or through Authority direction in prior Decisions or motion rulings. Finally, the Authority reaffirms that the fourth Program Objective, prioritizing increased resilience, shall be explicitly guided by a goal of 40% deployment amongst low-income populations or in Distressed Municipalities, in line with the Justice 40 goal set in the Storage Decision. Storage Decision, p. 13.

IV. AUTHORITY ANALYSIS

A. PROGRAM OVERVIEW

Public Act 21-53, codified as General Statutes § 16-243cc, established statewide energy storage deployment goals, namely: (1) 300 MW by December 31, 2024; (2) 650 MW by December 31, 2027; and (3) 1,000 MW by December 31, 2030. Further, PA 21-53 § 2, codified as General Statutes § 16-243ee, directed the Authority to develop the Program authorized in the Storage Decision, while PA 21-53 § 3, codified as General Statutes § 16-243dd, authorized DEEP to competitively procure energy storage projects. The Authority subsequently established an ESS Program deployment target of 580 MW by the end of 2030 to help achieve these statewide targets. Storage Decision, p. 5.

Pursuant to prior Authority Decisions, energy storage projects under the ESS Program are eligible for both enrollment and performance-based incentives, depending on customer type, as shown in Tables 2 and 3. Enrollment incentives vary based on whether the host customer is a grid-edge or non-grid-edge residential customer, or a priority commercial and industrial (C&I) customer. Performance-based incentives differ according to whether the customer is a standard, underserved, or low-income residential customer, or a small- and medium- or large-commercial customer. Energy storage increases the affordability, resilience, and reliability of the state's electric grid, and can help reduce carbon emissions from the state's power sector.

Table 1: Program Deployment Targets[1]

Customer Class	TOTAL
Residential	150 MW
Commercial	430 MW
Total	**580 MW**

Year 4 Decision, p. 38.

Table 2: ESS Enrollment Incentives

Customer Type	Incentive Amount
Priority Commercial	$10/kWh
Non-Grid Edge Residential	$30/kWh
Grid Edge Residential	$130/kWh

Year 5 Decision, p. 29.

Table 3: ESS Performance Incentives

Customer Type	Total Annual Incentive Amount
Small & Medium Commercial	$325/kW-year for Years 1–5; $175/kW-year for Years 6–10
Large Commercial	$275/kW-year for Years 1–5; $175/kW-year for Years 6–10
Standard Residential	$300/kW
Underserved Residential	$450/kW
Low-Income Residential	$550/kW

Year 5 Decision, p. 29.

[1] With the adoption of Construct 5, the Program no longer includes an automatic declining block incentive structure between tranches. Year 5 Decision, pp. 14, 21. Additionally, the Year 4 Decision reallocated the Program's MW capacity from the original distribution approved in the Storage Decision, shifting residential MWs to the commercial segment. Year 4 Decision, pp. 36–38.

Tables 4 and 5, below, provide a summary of the number of C&I and residential ESS projects approved by the Program Administrators from January 1, 2022 to June 30, 2026. As can be seen from the tables, 133.60 MW of C&I energy storage projects and 21.41 MW of residential energy storage projects have been approved by the Program Administrators and are currently active.[2]

Table 4: Commercial Project Application Data as of June 30, 2026

Size Category	Number of Approved/Complete Projects	Total System Power Rating (MW)	Total System Energy Capacity (kWh)
Large C&I	**36**	**95.85**	**229,990**
Eversource	31	87.34	202,332
UI	5	8.51	27,658
Medium C&I	**22**	**30.28**	**77,056**
Eversource	17	27.86	70,994
UI	5	2.42	6,062
Small C&I	**14**	**7.47**	**25,142**
Eversource	12	6.71	23,410
UI	2	0.76	1,732
Grand Total	**72**	**133.60**	**332,188**

Program Administrator Order No. 3 Compliance, Aug. 3, 2026, Att. 2, pp. 6–7, 29.

Table 5: Residential Project Application Data as of June 30, 2026

	Number of Approved/ Completed Projects	Total System Power Rating (MW)	Total System Energy Capacity (kWh)	Low Income (# of Projects)	Underserved Community (# of Projects)
Eversource	1,461	18.90	38,007	101	166
UI	352	2.51	5,821	175	61
Grand Total	**1,813**	**21.41**	**43,828**	**276**	**227**

Program Administrator Order No. 3 Compliance, Aug. 3, 2026, Att. 2, pp. 6–7, 29.

[2] Tables 4 and 5 exclude withdrawn or canceled projects, meaning the actual total number of MWs approved by the Program Administrators over the life of the Program is higher. See Program Administrator Order No. 3 Compliance, Aug. 3, 2026, Att. 2, pp. 6–7. For more granular and up-to-date data, see the Program's data dashboard, which is updated daily, here: Energy Storage Solutions Performance Report – Energy Storage Solutions.

B. BIDIRECTIONAL EV PARTICIPATION

1. Background

During last year's annual ESS Program review, the Authority directed the ESS Program Administrators to establish and jointly lead a Bidirectional EV Working Group. Year 5 Decision, p. 60. On behalf of the Working Group, the Program Administrators were required to submit a Bidirectional EV Report presenting the group's findings and recommendations regarding the integration of bidirectional EVs into the ESS Program. Id.

The Program Administrators filed the Bidirectional EV Report (Report) on July 29, 2026. See Program Administrator Order No. 20 Compliance, July 29, 2026. The Report recommended allowing commercial bidirectional EVs with a minimum discharge capacity of 20 kW per charging port to participate in the ESS Program, provided they are not simultaneously enrolled in the state's managed charging program. Id., Att. 1, p. 61. Under this recommendation, eligible commercial bidirectional EVs would receive the existing small/medium commercial ESS performance incentive for a 10-year enrollment period but would not be eligible for an enrollment incentive, as the Report concluded that this structure maintains a positive Ratepayer Impact Measure (RIM) score. Id., pp. 58, 61–62.

For residential bidirectional EVs, the Report did not recommend immediate inclusion in the ESS Program. Program Administrator Order No. 20 Compliance, July 29, 2026, Att. 1, p. 62. Instead, the Report recommended establishing a pathway with defined milestones that should be achieved before residential participation is considered. Id. These milestones included, among other things, completion of the Bidirectional Energy Innovative Energy Solutions (IES) pilot, incorporation of lessons learned from ongoing Massachusetts demonstrations, resolution of issues related to dual participation in the managed charging and ESS Programs, successful implementation of updated interconnection requirements, and clarification of metering and distributed generation policy considerations. Id., pp. 62–63. The Report recommended revisiting residential bidirectional EV participation during next year's ESS Program review if the Authority determines that doing so remains a priority. Id., p. 63.

As discussed above, the Report did not recommend allowing simultaneous enrollment in the ESS and managed charging programs, because of several implementation challenges. Program Administrator Order No. 20 Compliance, July 29, 2026, Att. 1, p. 38. First, absent coordination between the two programs, customer behavior could produce a "timer-peak" effect in which ESS-enrolled vehicles begin charging simultaneously at the conclusion of a dispatch event after discharging energy, thereby undermining the load-shifting objectives of managed charging. Id., p. 36. Stakeholders also raised concerns regarding double penalization, as under the current ESS Program design, charging during an ESS event may negatively affect ESS performance incentives, while the same charging activity could also be penalized under the managed charging program, potentially subjecting a customer to overlapping negative consequences for the same action. Id.

In addition, operating two programs concurrently on the same asset using separate charging and discharging signals could require real-time communication between the respective technology platforms, visibility into the vehicle's state of charge, and a coordinated customer-facing interface, creating significant implementation complexity. Id., p. 37. Stakeholders also raised customer-related concerns, including the need to enroll in two programs with different compensation structures and the need to ensure that customers retain control over EV dispatch and maintain a state of charge sufficient to meet their transportation needs. Program Administrator Order No. 20 Compliance, July 29, 2026, Att. 1, p. 37. Further, under current EV program rules, receipt of a make-ready or electric vehicle supply equipment (EVSE) rebates for residential customers are conditioned on 24 months of managed charging enrollment, which would prevent such customers from enrolling in the ESS Program during that period. Id., p. 38. Accordingly, until these issues are resolved, the Report did not recommend allowing dual participation.

The Report also recommended several technical and programmatic modifications to facilitate bidirectional EV participation. These recommendations included:

- treating bidirectional EVs as behind-the-meter (BTM) resources, even where the only on-site load is EV charging;
- removing the existing islanding and backup power requirement for commercial bidirectional EV installations;
- using the maximum charging capacity of the bidirectional EVSE, rather than historical site demand, when applying the ESS Program's sizing limitation;
- requiring several applicable safety and communication certifications;
- requiring completed distributed energy resource management system (DERMS) integration; and
- requiring the same static and interval telemetry fields currently required under the ESS Program, while allowing discretion to waive the 15-minute reporting interval for state-of-charge data.

Id., pp. 65–66. Separately, in the Year 5 Decision, the Authority directed the EDCs, on behalf of the Interconnection Working Group, to file recommended revisions to the interconnection process for bidirectional EVs, including proposed revisions to the Interconnection Guidelines and any necessary modifications to the PowerClerk system. Year 5 Decision, p. 61. The EDCs submitted these compliance filings on July 1, 2026. See EDC Order No. 25 Compliance, July 1, 2026.

The Authority requested written comments on both the Report and the EDCs' recommended interconnection changes for bidirectional EVs. Notice, Aug. 12, 2026, p. 4. The Authority asked stakeholders to identify any specific recommendations they opposed and propose alternative approaches where appropriate. Id.

2. Stakeholder Comments

Eversource, UI, and CGB largely echoed the recommendations in the Report, with several additions discussed below. UI Comments, Aug. 27, 2026, pp. 5–7; Eversource Comments, Aug. 28, 2026, pp. 6–9, CGB Comments, Aug. 28, 2026, pp. 4–5. UI

reiterated that unmanaged interactions between charging and discharging programs could result in conflicting dispatch signals, increased customer confusion, technology integration challenges, and adverse charging behavior that undermines the objectives of both programs. UI Comments, Aug. 27, 2026, p. 6. UI therefore recommended resolving these issues before allowing dual participation. Id. Eversource similarly recommended that residential EV enrollment in the ESS Program be deferred until several additional conditions are satisfied, including evidence that customers are willing to participate in vehicle-to-grid (V2G) programs; that participating customers are home and their vehicles are plugged in during events; that customer vehicles provide a meaningful amount of discharge capacity during events; that EVSE can integrate with a DERMS; and that DERMS platforms can both send EVSE dispatch signals and receive EVSE dispatch performance data. Eversource Comments, Aug. 28, 2026, p. 7.

OCC agreed that participation should be limited to a single program, either ESS or managed charging, to avoid duplicative incentives for similar grid benefits. OCC Comments, Aug. 28, 2026, p. 3. OCC explained that the two programs are inherently linked because ESS dispatch necessarily precludes simultaneous charging. Id. OCC also supported focusing initially on commercial bidirectional EVs, citing the importance of the commercial sector to achieving the ESS Program's overall goals, the ongoing residential Bidirectional Energy IES Pilot, and the more individualized and less predictable usage patterns of residential customers compared to commercial customers. Id., pp. 3–4. OCC further supported most of the technical requirements for bidirectional EV participation in the ESS Program proposed in the Report. Id., p. 4. OCC cautioned, however, against potentially removing the requirement to report stored kWh data at 15-minute intervals, noting that less frequent reporting could result in telemetry delays that hinder troubleshooting and performance monitoring. OCC Comments, Aug. 28, 2026, p. 4.

EV.Energy advocated for two primary changes to the Report's recommendations: (1) establishing a timely framework to enable bidirectional EVs to participate simultaneously in the ESS and managed charging programs; and (2) accelerating the incorporation of residential bidirectional EVs into the ESS Program. EV.Energy Comments, Aug. 28, 2026, p. 1. Although EV.Energy agreed that the ESS Program provides greater grid value than the managed charging program, it argued that characterizing the programs in those terms was inappropriate. Id., p. 2. Specifically, EV.Energy emphasized that managed charging shifts EV charging to off-peak periods rather than discharging energy during peak periods. Id., pp. 2–3. Accordingly, EV.Energy argued that dual enrollment could maximize grid benefits, particularly if software-based charging solutions prevent EVs from resuming charging during peak periods. Id., p. 5.

EV.Energy further stated that more than 12 passenger EV models and approximately 3,000 individual bidirectional EVs are currently registered in Connecticut and capable of discharging. EV.Energy Comments, Aug. 28, 2026, p. 4. EV.Energy argued that deferring residential EV enrollment for another year would unnecessarily exclude a potentially beneficial source of discharge capacity from the ESS Program. Id. If residential enrollment is nevertheless deferred, EV.Energy requested that the Program

Administrators establish formal program-year goals for resolving the outstanding issues and provide quarterly progress updates. Id., p. 6.

Finally, EV.Energy agreed that the technical requirements proposed in the Report were reasonable and recommended establishing a process for updating those requirements as applicable standards evolve, without requiring additional filings for each update. Id.

Tesla stated that a program enabling EVs to discharge energy to the grid provides greater benefits than the load-shifting that currently characterizes the managed charging program. Tesla Comments, Aug. 28, 2026, p. 2. Tesla nevertheless opposed limiting bidirectional EV participation to a single program, either managed charging or ESS, asserting that the challenges associated with dual enrollment are contractual rather than programmatic in nature. Id., p. 3. Tesla stated, however, that if prohibiting dual participation is necessary, it would not oppose limiting bidirectional EVs to a single program during the initial years while the Authority works through these issues and develops a more comprehensive framework. Id., pp. 3–4.

Like EV.Energy, Tesla also supported allowing residential bidirectional EVs to participate in the ESS Program. Id., p. 3. Tesla cited the successful launch of programs in Texas and California, the recent codification of UL certification pathways, and the expansion of bidirectional capabilities in Tesla models, including the Cybertruck and certain Model Y vehicles. Tesla Comments, Aug. 28, 2026, p. 3. Tesla emphasized that ratepayers would be protected because residential bidirectional EV owners would receive incentives only for services actually performed. Id.

Tesla also supported the revised Interconnection Guidelines filed by the EDCs and the technical requirements identified in the Report. Id., pp. 4–5. Tesla recommended, however, that the communication standards be treated as guidelines rather than mandatory requirements, including by expressly preserving the Report's proposed ability for the Program Administrators to grant exemptions from those standards. Tesla Comments, Aug. 28, 2026, pp. 4–5. Finally, Tesla expressed concern that the Program Manual revisions proposed by the Program Administrators, specifically the UL 1741 requirement on page 108, do not fully capture the range of certification pathways described in the Report. Id., p. 5. Tesla emphasized the importance of ensuring that the Program Manual accurately reflects the distinctions and nuances of the certification pathways discussed in the Report. Id.

The Vehicle Grid Integration Council (VGIC) argued that, assuming participation is limited to a single program, participation in the ESS Program provides greater overall benefits to ratepayers than participation in Connecticut's managed charging program for bidirectional EV charging systems. VGIC Comments, Aug. 28, 2026, p. 5. VGIC attributed this difference primarily to the greater per-vehicle depth of response available under the ESS Program. Id. For example, citing the 2024 managed charging program evaluation report, VGIC stated that managed charging typically provides less than 0.2 kW of response per vehicle, whereas bidirectional EV charging systems offer approximately 9.6 to 11.5 kW of export capability. Id., pp. 5–6. VGIC further noted that the EV market

is rapidly moving toward bidirectional capability, citing programs in other states and the increasing number of bidirectional-capable EV models. Id., pp. 7–9. VGIC estimated that enrolling the approximately 3,000 bidirectional-capable EVs currently in Connecticut in the ESS Program could provide approximately 34 MW of nameplate capacity, which VGIC characterized as a significant potential benefit to ratepayers. VGIC Comments, Aug. 28, 2026, p. 11.

VGIC disagreed with the Report's recommendation to defer residential bidirectional EV enrollment in the ESS Program. Id., p. 13. VGIC stated that the risk to ratepayers would be low because incentives would be based on actual performance. Id., p. 7. VGIC also asserted that the Participant Cost Test (PCT) score for residential bidirectional EV charging systems would exceed that of residential stationary storage systems, which currently have a PCT below 1 but remain eligible for the ESS Program. Id., pp. 14–15. In addition, VGIC contended that the residential bidirectional EV market is more mature than the commercial market, excluding school buses, based on the rapid expansion of residential bidirectional EV offerings. VGIC Comments, Aug. 28, 2026, pp. 16–17.

VGIC further argued that, even if the residential market is not yet sufficiently developed, deferring eligibility could create a "chicken and egg" problem because ESS performance incentives could themselves facilitate market development. Id., p. 17. VGIC also asserted that completion of additional residential bidirectional EV pilots is not necessary before allowing residential participation in the ESS Program because participants in the IES and Massachusetts pilots also participated in the Bidirectional EV Working Group and contributed to development of the Report's recommendations. Id., p. 18. With respect to dual participation in ESS and managed charging, VGIC maintained that the identified obstacles concern implementation and program coordination and therefore do not justify excluding residential bidirectional EVs from the ESS Program. Id., p. 19. VGIC suggested that dual participation could remain prohibited temporarily while the operational issues are addressed in a future proceeding. VGIC Comments, Aug. 28, 2026, p. 19. Finally, VGIC argued that metering and interconnection issues should not be used as a basis for excluding residential bidirectional EVs because those issues are not unique to residential bidirectional EVs and presumably would also apply to commercial bidirectional EVs and stationary storage. Id., pp. 20–21.

VGIC supported the Report's technical requirements, subject to two specific qualifications. Id., pp. 21–22. First, VGIC recommended modifying the requirement that all systems satisfy UL 9741 to permit AC-coupled systems that cannot be certified to UL 9741 but can be certified to UL 1741 SC, asserting that UL 9741 does not apply to AC-coupled systems. Id., p. 22. Second, VGIC recommended that ISO 15118-20 not be treated as a rigid requirement and supported the Report's recommendation to permit exceptions while the applicable certification and testing ecosystem matures. VGIC Comments, Aug. 28, 2026, p. 22. VGIC otherwise supported the Report's recommendations and the revised Interconnection Guidelines incorporating bidirectional EVs. Id., pp. 23–25.

3. Authority Analysis

a. Overview

Consistent with the Program Administrators' recommendation, eligible commercial bidirectional EV charging systems will be allowed to enroll in the ESS Program beginning January 1, 2027, at the existing small/medium performance incentive rate, subject to the requirements established below. Dual enrollment in the managed charging program will be prohibited due to the technical, operational, and compensation-related concerns discussed below.

A phased approach to incorporating bidirectional EV charging systems into the ESS Program is appropriate because it will allow the Authority, Program Administrators, and other stakeholders to gain experience with the integration and operation of these resources while initially limiting participation to the vehicle and customer segments that are best positioned to provide reliable grid benefits.

Residential bidirectional EV participation remains a priority and will be revisited during a future annual ESS Program review. The Authority's rationale for initially limiting participation to commercial bidirectional EV charging systems, the requirements applicable to eligible commercial systems, and the process for evaluating future residential participation are discussed below.

b. Benefits for Program Inclusion

Bidirectional EV charging systems present a meaningful opportunity to expand the resources available to the ESS Program and provide additional benefits to ratepayers. Unlike conventional managed charging, which primarily provides grid value by shifting EV charging away from periods of high demand, bidirectional EV charging systems can provide an additional source of grid flexibility by discharging stored energy during ESS active dispatch events, thereby reducing net system demand. Their ability to provide both transportation services and grid services also creates an opportunity to leverage customer-funded or otherwise necessary vehicle and charging infrastructure as a distributed energy resource.

The ESS Program's benefit-cost analysis (BCA) may also support the inclusion of commercial bidirectional EV charging systems. The overall Program Ratepayer Impact Measure (RIM) score is 1.55, while the commercial sector has a RIM score of 1.84. Program Administrator Order No. 3 Compliance, Aug. 3, 2026, Att. 2, pp. 72, 74. However, the Connecticut-specific commercial RIM score of 1.23 falls short of the 1.4 RIM target, while the overall CT-RIM score is only 1.0. Program Administrator Order No. 3 Compliance, Aug. 3, 2026, Att. 2, pp. 73, 75.

In addition to the direct grid benefits associated with dispatchable battery capacity, ESS participation may improve the economics of deploying bidirectional charging infrastructure and thereby support broader adoption of V2G-capable technologies. This consideration may be particularly important for commercial EV fleets, for which performance incentives can provide a direct revenue stream in exchange for making

otherwise necessary vehicle battery capacity available as a flexible grid resource. Early participation by commercial fleets can also generate operational experience and performance data that may inform the eventual expansion of V2G participation to other customer segments.

c. Commercial vs. Residential Eligibility

At this time, the Authority will limit ESS Program enrollment for bidirectional EVs to EVSE installed at commercial accounts, as this customer segment is best positioned to participate effectively in the ESS Program under current market and operating conditions.

The Report identified several factors supporting this distinction. Commercial fleet operators generally have more predictable vehicle schedules and greater ability to manage vehicle availability, state of charge, and dispatch requirements. Program Administrator Order No. 20 Compliance, July 29, 2026, Att. 1, p. 62. Electric school buses, for example, are more likely to be available during ESS dispatch periods occurring in the evening during the Program's summer dispatch season because school buses are generally not in use during the summer. Id., pp. 15–16. Commercial participants are also more likely to deploy multiple charging ports at a single site, which can increase the amount of dispatchable capacity associated with each enrollment and improve the administrative efficiency and total grid value of participation.

Residential applications present greater operational uncertainty. Residential EV use is inherently more variable, and an individual vehicle may not be plugged in, may not have sufficient state of charge, or may be needed for transportation during an ESS active dispatch event. These considerations create additional uncertainty regarding customer availability, state-of-charge management, and the ability to consistently participate in active dispatch. The Report appropriately identified these factors, as well as the potential conflict between transportation needs and grid dispatch, as important considerations for residential V2G participation. Id., pp. 15–16, 61.

The Program's performance-based incentive structure provides important ratepayer protection because participating customers are compensated only based on actual performance. Nevertheless, the Authority is particularly concerned about the potential customer impacts of enrolling residential bidirectional EVs in the ESS Program before the operational and customer-facing issues associated with residential participation are sufficiently understood. For example, a residential customer could be unable to use an EV when needed for transportation because the vehicle participated in an active dispatch event that discharged the battery to a state of charge insufficient to meet the customer's transportation needs. Such outcomes could undermine customer confidence in V2G technology and discourage broader residential adoption, to the detriment of Connecticut's longer-term grid and EV objectives. Further, individual residential customers generally have less ability than commercial fleet operators to manage vehicle availability and coordinate EV use with grid dispatch requirements.

Nevertheless, residential bidirectional EVs could ultimately provide benefits to customers and the grid. Accordingly, the Authority's decision to initially limit participation

to commercial customers is a matter of sequencing, not a determination that residential bidirectional EVs are unsuitable for the ESS Program. A staged approach will allow the ESS Program to establish operational experience with V2G resources, identify and address technical issues, and develop a stronger evidentiary record regarding residential performance before extending eligibility more broadly.

The Authority will therefore revisit residential bidirectional EV eligibility as part of a future annual ESS Program review. In advance of that review, the Authority directs the Program Administrators to submit, no later than August 1, 2027, a compliance filing containing a recommendation as to whether residential bidirectional EVs should be eligible to participate in the ESS Program and, if so, under what conditions.

The Program Administrators' compliance filing shall include, at a minimum, the following:

1. **Pilot Results**. A detailed summary of the Bidirectional Energy IES pilot and Massachusetts Clean Energy Center (MassCEC) Vehicle to Everything (V2X) pilot results, including, where known, EV performance, dispatch participation and success rates, customer experience, and any identified barriers to residential V2G participation.

2. **Market and Technology Readiness**. An updated assessment of the residential bidirectional EV market in Connecticut, including the number and types of residential EVs reasonably expected to be eligible for ESS participation and any material changes in market or technology readiness since the filing of the original Bidirectional EV Report.

3. **Interconnection**. An assessment of the EDCs' experience applying the revised bidirectional EV interconnection requirements, including any implementation issues identified through commercial participation and the IES pilot and any additional modifications that may be necessary to facilitate residential participation. Although this will be a joint filing, the EDCs shall be solely responsible for this portion of the filing because the EDCs administer the interconnection process. If the assessment identifies a need for changes to the interconnection requirements, the EDCs shall submit both clean and redlined versions of the applicable Interconnection Guidelines as part of the filing.

4. **BCA**. An updated assessment of the BCA impacts associated with residential bidirectional EV participation under a proposed incentive structure in which performance incentives for residential bidirectional EVs would match the performance incentives applicable to standalone residential storage and no enrollment incentives would be provided.

5. **Customer-Facing Issues**. An evaluation of customer-facing issues associated with residential participation and a proposed mitigation strategy. This evaluation shall consider, among other things, whether a minimum state-of-charge requirement should apply to residential bidirectional EVs

participating in active dispatch, as well as other measures to mitigate potential vehicle damage and the risk that customers may be unable to use their EVs to meet transportation needs.

6. **Program Requirements**. Recommendations regarding any additional residential-specific eligibility requirements that should differ from or supplement the requirements applicable to commercial bidirectional EV charging systems. As part of this evaluation, the Program Administrators shall also consider whether the 20 kW per charging port minimum discharge capacity should be modified to allow for residential participation.

7. **Implementation Recommendations**. A proposed framework and implementation timeline for residential bidirectional EV participation, incorporating all the above.

The Authority expects this filing to provide sufficient quantitative, operational, and customer-experience information to determine whether residential bidirectional EV participation should be authorized as part of the subsequent annual ESS Program review.

Providing a clear signal regarding the potential future availability of ESS incentives for residential bidirectional EVs will be important to support continued market development. Accordingly, the Authority expects that, if the identified challenges are satisfactorily resolved and the record demonstrates that residential participation can provide benefits commensurate with its costs, residential bidirectional EVs may be considered for inclusion in the ESS Program in the subsequent program year (i.e., 2028).

d. Dual Program Enrollment

The Authority will prohibit dual participation by bidirectional EV charging systems in the ESS and managed charging programs. The potential incremental benefits of dual participation do not justify the technical, operational, customer-facing, and ratepayer-compensation issues associated with administering two programs on the same asset. Accordingly, the Authority is not inclined to revisit this determination in the immediate term.

First, dual participation presents significant technical and operational challenges. A bidirectional EV participating in both programs would be subject to charging and discharging signals originating from separate program requirements and potentially separate technology platforms. The DERMS and associated EVSE controls would need to receive, prioritize, and coordinate these signals in real time while maintaining visibility into the vehicle's state of charge and availability. The system would also need to appropriately attribute the vehicle's performance to each program, including distinguishing charging behavior associated with managed charging from discharging behavior associated with an ESS event. These functions require reliable communication among the DERMS, EVSE, EV, and applicable program platforms and could require significant additional integration, testing, and operational coordination. Until these capabilities are demonstrated at scale, allowing dual participation could create uncertainty regarding which program signal governs the asset at a particular time and could make it

more difficult to determine whether a participant has satisfied the performance requirements of either program.

The potential interaction between the programs also creates a risk that the operation of one program could undermine the objectives of the other. For example, a managed charging signal could limit charging or otherwise affect the vehicle's state of charge in a manner that reduces the vehicle's ability to respond to an ESS dispatch event called later. Avoiding these outcomes would require the programs to be coordinated not merely at the enrollment level, but at the dispatch and control level. See Program Administrator Order No. 20 Compliance, July 29, 2026, Att. 1, pp. 36–37. The Authority is not persuaded that the benefits of dual enrollment warrant undertaking this additional level of program integration.

Second, dual enrollment could unnecessarily complicate the customer experience. A customer participating in two programs would be required to understand and comply with two sets of eligibility requirements, program rules, performance obligations, compensation structures, and dispatch windows. The customer would also need to understand how participation in one program could affect the vehicle's ability to respond to the other program. These complications could make it difficult for customers to understand how their vehicle will operate, what compensation they can expect to receive, and whether the vehicle will remain available for their transportation needs. The Authority is particularly concerned that unnecessary complexity at the point of enrollment or during program participation could discourage participation and undermine customer confidence in bidirectional EV technology, which remains an emerging resource.

Third, and most importantly, the Authority must ensure that ratepayers do not provide duplicative compensation for the same underlying grid benefit. Managed charging and ESS can provide distinct benefits: managed charging generally shifts consumption to different hours, while ESS provides a dispatchable reduction in net load through discharge. However, when a bidirectional EV is enrolled in ESS and discharges during a period of system need, the vehicle necessarily is not charging during that period. The ESS dispatch therefore can simultaneously provide the principal benefit that managed charging is intended to achieve during system peaks, reducing or avoiding charging load, while also providing the additional benefit of injecting energy into the grid.

To the extent the relevant system peak period would occur at the same time regardless of which program the customer is enrolled in, enrolling the same vehicle in both programs could result in two incentive streams being paid for behavior that is substantially overlapping. The Authority therefore must distinguish between circumstances in which dual enrollment produces a genuinely incremental grid benefit and circumstances in which it merely increases compensation for a resource response that the ESS Program already incentivizes.

This concern is particularly important because the ESS Program is already designed to compensate resources for their performance in responding to grid needs. A second incentive is not warranted simply because the same resource could technically satisfy the requirements of another program. Rather, additional compensation should be

justified by a material change in customer behavior that would not otherwise occur. Dual enrollment would not consistently produce such an incremental benefit sufficient to justify the additional administrative and technical complexity.

This approach is consistent with the treatment of other storage resources participating in the ESS Program. A standalone commercial stationary battery used for demand charge reduction can both avoid charging during peak periods and discharge during those periods; however, the ESS Program does not provide a separate managed charging incentive for the avoided charging associated with this behavior. The Authority therefore sees no compelling reason to provide bidirectional EVs with an additional incentive for a comparable charging behavior merely because the underlying asset is an EV. Such a distinction could result in materially different compensation for resources providing substantially similar grid services and could undermine the principle that ESS incentives should be commensurate with the incremental benefits provided to ratepayers.

Accordingly, the Authority will prohibit dual participation by bidirectional EV charging systems enrolled in the ESS and managed charging programs. This approach will enable bidirectional EV participation in the ESS Program while avoiding the additional technical complexity and potential ratepayer value concerns that could arise from dual enrollment in both programs. It will also allow demonstration of bidirectional EV performance, dispatch, customer participation, and program administration within a single incentive structure.

e. Incentives

Commercial bidirectional EVs participating in the ESS Program shall be eligible solely for performance incentives at the current incentive rate applicable to the small/medium commercial customer class. Applying the existing commercial incentive rate provides a consistent and administratively straightforward approach while avoiding the need to establish a separate incentive level before sufficient operating and cost data are available. It also supports the Program's objective of ensuring that the addition of bidirectional EV resources does not adversely affect ratepayer benefits. The commercial customer class currently has a positive CT-RIM score of 1.23 at existing incentive levels, including enrollment incentives, indicating that a performance-only incentive structure can maintain positive ratepayer benefits. Program Administrator Order No. 3 Compliance, Aug. 3, 2026, Att. 21, p. 75.

Further, bidirectional EVs shall not receive an enrollment incentive. Unlike an enrollment incentive, which provides compensation based principally on a resource's enrollment, a performance incentive is paid only when a participating resource responds to an active dispatch event and delivers measurable grid value. The latter approach is particularly appropriate for bidirectional EV participation because there is limited operating experience regarding the frequency, duration, and consistency with which these resources will be available for dispatch.

Bidirectional EVs have operational constraints that do not apply to standalone energy storage systems. EV availability can depend on transportation needs, charging schedules, and other customer-specific circumstances. These factors make it difficult to

establish an enrollment incentive that can be demonstrated to provide benefits commensurate with its cost to ratepayers.

Accordingly, compensation based exclusively on demonstrated performance during active dispatch events strikes an appropriate balance between encouraging early deployment of bidirectional EV resources and protecting ratepayers.

f. Program Requirement Changes

As identified in the Report, existing Program requirements must be clarified or waived to allow commercial bidirectional EVs to participate in the ESS Program.

First, EVSE enrolling in the ESS Program shall be considered BTM resources. Certain charging sites may have no load other than the EV charger. If such a site were solely occupied by a stationary battery, the battery would be considered FTM and therefore would be ineligible to participate in the ESS Program. Program Administrator Order No. 20 Compliance, July 29, 2026, Att. 1, p. 29. However, the primary purpose of an EV charging site is to provide transportation-related charging services, rather than to operate as a standalone grid resource. Accordingly, it is reasonable to treat EVSE as BTM for purposes of ESS Program eligibility, regardless of whether other customer load is present at the charging site.

Additionally, the ESS Program currently requires enrolled resources to be capable of islanding and providing backup power during grid outages. Id. This requirement is not appropriate for bidirectional EVs because the vehicles are mobile and may not be connected to the applicable EVSE when an outage occurs. In addition, requiring an EV to remain available for backup power could interfere with its primary transportation function. The requirement is also of limited practical value at charging sites where the EVSE serves no load other than the vehicle itself. Accordingly, the Authority waives the islanding and backup-power requirement for all bidirectional EV charging systems enrolling in the ESS Program.

g. MW Cap and PCT

The Authority clarifies two quantitative considerations applicable to bidirectional EVs participating in the ESS Program.

First, the Report proposed that the appropriate cost basis for evaluating the economics of bidirectional EV participation in the ESS Program is the incremental cost of moving from a unidirectional EV to a fully V2G-capable system, rather than the full cost of the EV and EVSE. Program Administrator Order No. 20 Compliance, July 29, 2026, Att. 1, p. 54. The Authority agrees. The primary purpose of a bidirectional EV is transportation, rather than grid services. Accordingly, the economics of ESS participation from the perspective of an EV owner should be evaluated based on the incremental costs necessary to enable the EV or EVSE to provide bidirectional functionality, rather than costs associated with the vehicle and charging equipment that the customer would incur for transportation purposes regardless of ESS participation.

Second, the Report recommended that, for purposes of the Program's 580 MW deployment target, the export rating, in kW, of EVSE enrolled in the ESS Program be counted toward the Program's MW goal. Id., p. 64. The Authority agrees that the export rating shall be used for this purpose unless performance data demonstrates that bidirectional EVs consistently perform substantially below their rated export capacity. This approach is consistent with the treatment of stationary storage, for which the full export rating is counted toward the Program's MW deployment target upon enrollment, notwithstanding that actual performance during dispatch may be lower. Counting bidirectional EVs on the same basis promotes consistency across resource types and avoids establishing a different treatment for EV-based storage without a demonstrated need to do so. Accordingly, absent compelling evidence demonstrating that the rated export capacity materially overstates the capacity reasonably available from enrolled bidirectional EVs, the Authority does not anticipate revisiting this determination.

h. Technical and Telemetry Requirements

The Report proposed several technical requirements and certifications for bidirectional EV participation, as summarized in Table 6 below. Given the broad stakeholder support for these requirements, the Authority approves the technical standards identified in Table 6, subject to the clarifications discussed below.

Table 6: Standards and Certifications Applicable to Bidirectional EV Participation in the ESS Program

Standard/Certification	Description	Applicable to EVSE?	Applicable to EV?	Recommendation
UL 1741 SB	Enhanced inverter/grid standard with advanced functions. Already required by EDCs for interconnection. Applicable pathway for DC-coupled EVSE.	Yes	No	Require for DC-coupled EVSE as well as for stationary storage
UL 1741 SC	Extension of UL 1741 designed for mobile, onboard vehicle inverters (AC-coupled systems). Requires paired EV to be SAE J3072 certified. Finalized in May 2026.	Yes (AC-Coupled)	No	Require for AC-coupled EVSE upon finalization

Standard/Certification	Description	Applicable to EVSE?	Applicable to EV?	Recommendation
UL 1741 SB CRD	Pathway for jointly certifying a specific EV-EVSE pair as a composite DER under the SB framework. Available now; used by some manufacturers (e.g., Tesla).	Yes	Yes (Paired)	Permitted as alternative pathway for composite DER pairings (AC-coupled)
SAE J3072	Defines bidirectional energy transfer requirements for plug-in EVs paired with UL 1741 SC EVSE.	Yes (AC-Coupled)	Yes (AC-Coupled)	Require for EVs paired with UL 1741 SC EVSE; not a standalone requirement
UL 9741	Safety standard for bidirectional EVSE capable of exporting power to the grid or premises.	Yes	No	Require
UL 2594	Safety standard for Level 1 and Level 2 AC EVSE.	Yes (AC)	No	Require for Level 1/2 AC chargers
UL 2202	Safety standard for DC fast charging EVSE.	Yes (DC)	No	Require for DC fast chargers
ISO 15118- 20	Governs EV-to-EVSE communication for bidirectional power transfer.	Yes	Yes (partial)	Require, with Program Administrator discretion to grant exceptions where certification ecosystem not yet mature

Program Administrator Order No. 20 Compliance, July 29, 2026, Att. 1, pp. 44–45.

As noted by VGIC, certain AC-coupled systems may be unable to obtain UL 9741 certification but may be capable of obtaining UL 1741 SC certification. VGIC Comments, Aug. 28, 2026, p. 22. The Authority cannot independently determine from the record whether UL 9741 is technically inapplicable to all AC-coupled systems. Nevertheless, rigid application of specific certification standards could unnecessarily restrict participation in a rapidly evolving technology market, particularly where an alternative or

subsequently developed certification provides comparable assurance of safety and functionality.

Accordingly, for the purposes of ESS enrollment, the Authority authorizes the Program Administrators to waive any technical requirement identified in Table 6 when an applicant demonstrates either that: (1) an alternative or subsequently developed certification or standard fulfills the same substantive purpose as the applicable requirement; or (2) the specified certification is not technically applicable or reasonably obtainable for a particular class of resources. The Program Administrators shall incorporate this clarification into the revised Program Manual filed in compliance with this Decision. The burden of demonstrating that a waiver is warranted shall rest with the applicant. The Program Administrators shall not be required to establish independently that an alternative certification satisfies the applicable requirement absent a sufficient showing by the applicant.

The Authority does not extend this waiver authority to the Program's telemetry requirements. The Report recommended maintaining the current requirement that enrolled resources provide telemetry data at 15-minute intervals, while also allowing the Program Administrators discretion to waive that requirement for stored kWh because a working group participant indicated that some EVs may be unable to consistently provide data at that frequency. Program Administrator Order No. 20 Compliance, July 29, 2026, Att. 1, p. 51. However, detailed telemetry data is fundamental to effective ESS Program administration. Granular telemetry is necessary to evaluate resource performance and identify and troubleshoot operational issues. Accordingly, bidirectional EV charging systems enrolled in the ESS Program shall be required to provide stored kWh telemetry at 15-minute intervals, and the Program Administrators shall not waive this requirement.

If an enrolled bidirectional EV charging system fails to provide required discharge telemetry data for a particular period, the performance associated with that period shall be recorded as zero for purposes of calculating the applicable performance incentive. This approach appropriately places the risk of inadequate telemetry on the participant and avoids compensating a resource for performance that the Program cannot verify.

Finally, the Authority agrees with Tesla that the Program Manual revisions proposed by the Program Administrators do not appear to fully capture the technical requirements and certification pathways described in the Report. See Tesla Comments, Aug. 28, 2026, p. 5; Program Administrator Order No. 3 Compliance, Aug. 3, 2026, Att. 5, pp. 24–25. Accordingly, the Program Administrators shall carefully review and revise the Program Manual to ensure that it accurately and comprehensively incorporates all technical and programmatic requirements applicable to bidirectional EV participation identified in the Report and approved by the Authority. The revised Program Manual shall also clearly reflect the waiver authority established by this Decision and the requirement for 15-minute telemetry data.

i. Sizing Requirements

The Report recommended a minimum discharge capacity threshold of 20 kW per charging port for commercial bidirectional EV charging systems enrolling in the ESS

Program. Program Administrator Order No. 20 Compliance, July 29, 2026, Att. 1, p. 4. The Program Administrators explained that this threshold is intended to focus initial enrollment on direct current fast charging (DCFC) stations, as AC or Level 2 chargers typically have a maximum discharge capacity below 20 kW. Program Administrator Interrog. Resp. CAE-13, p. 1. According to the Program Administrators, focusing initially on DCFC chargers would streamline potential fleet-discharging use cases and facilitate smoother V2G integration into the ESS Program, while also reducing the need to enroll individual AC-coupled bidirectional EVs because Level 2 chargers generally lack an inverter. Id.

The Authority agrees with the 20 kW per port minimum for the first year of commercial bidirectional EV charging system enrollment. The threshold provides a reasonable means of focusing initial ESS Program participation on larger, more readily dispatchable commercial charging applications while the Program Administrators and the Authority gain experience with bidirectional EV enrollment, dispatch, telemetry, and performance. The Authority views this as an initial implementation threshold rather than a permanent limitation on the types of bidirectional EV resources that may participate in the ESS Program.

As the Program Administrators gain operational experience and data, and as the Authority considers residential eligibility, the Authority expects to revisit the threshold. In particular, the Authority does not intend to limit future eligibility solely to DCFC systems. The inability of a Level 2 or other AC charging system to meet the initial threshold, including circumstances in which the charger itself lacks an inverter and bidirectional functionality must instead be provided through the vehicle, should not constitute a permanent barrier to otherwise cost-effective participation. As the technology and market mature and the Program develops greater experience with bidirectional EV resources, the Authority will consider whether a lower threshold could expand participation while continuing to provide benefits commensurate with incentive costs.

Further, there shall be no maximum sizing limitation for EV charging systems enrolling in the ESS Program. The Report recommends using the maximum charging rating of the bidirectional EVSE as a proxy for historical maximum peak demand when applying the ESS Program's sizing limitation of 150% of the customer's annual peak demand, or 2 MW. Program Administrator Order No. 20 Compliance, July 29, 2026, Att. 1, p. 30. That limitation, however, was developed in connection with the Program's prior passive dispatch construct, which is no longer open to new enrollments. Year 2 Decision, pp. 20–21. The current Program construct, Construct 5, does not impose a maximum sizing limitation for active dispatch. Year 5 Decision, p. 23. Accordingly, to maintain consistency with the current Program design, there shall be no separate maximum size limit for bidirectional EV charging systems enrolling in the ESS Program.

j. Interconnection Guidelines

Consistent with the broad stakeholder support for the revised Interconnection Guidelines developed to facilitate interconnection of bidirectional EV charging systems, the Authority approves the revised Interconnection Guidelines and directs the EDCs to

use the revised Guidelines for all applicable bidirectional EV interconnection requests no later than January 4, 2027. See EDC Order No. 25 Compliance, July 1, 2026. By the same date, the EDCs shall also update their respective interconnection webpages to include the revised Interconnection Guidelines and shall file compliance with the Authority confirming that such updates have been completed.

However, implementation of the revised Interconnection Guidelines will provide the first significant opportunity to identify whether additional modifications are necessary. Accordingly, the EDCs shall monitor their implementation of the revised Interconnection Guidelines and identify any material issues, ambiguities, or necessary modifications. Any proposed revisions shall be included in the compliance filing addressing residential bidirectional EV eligibility described prior, which specifically addresses whether further revisions to the Interconnection Guidelines are warranted based on the EDCs' implementation experience.

k. Conclusion

The Authority approves commercial bidirectional EV charging system participation in the ESS Program beginning January 1, 2027, subject to the requirements and conditions established in this Decision and the final approved Program Manual. This initial eligibility is intended to provide the ESS Program with meaningful experience with V2G resources while maintaining appropriate protections for residential bidirectional EV owners.

The Authority considers residential bidirectional EV participation to remain an important future opportunity and has therefore established a defined process for evaluating residential eligibility as part of a subsequent annual ESS Program review.

In contrast, the Authority does not identify dual enrollment of bidirectional EV charging systems in the ESS and managed charging programs as an immediate priority. The Authority will require participating bidirectional EVs to enroll in a single program, based on the significant technical, operational, customer-facing, and ratepayer-compensation concerns discussed above.

Finally, any requirement, recommendation, or proposal contained in the Report that is not expressly addressed in this section is approved, provided that it is consistent with the determinations and requirements established elsewhere in this Decision.

C. ENROLLMENT INCENTIVE CLAWBACK

1. Background

During the Year 5 ESS annual review cycle, the Authority adopted Construct 5, which eliminated passive dispatch and significantly reduced upfront incentives in favor of a predominantly performance-based compensation structure. Year 5 Decision, pp. 20–21. This construct was intended to minimize ratepayer exposure while better aligning participant compensation with realized system value. Id. Construct 5 does not include a

clawback provision tied to participation in active dispatch, as active dispatch participation is not a condition for receipt of the enrollment incentive. Id., pp. 14-15.

Further, Section 3.7 of the ESS Program Manual provides that, once a customer who has received an enrollment incentive unenrolls from active dispatch, "there is no requirement to return any portion of the Enrollment Incentive." Motion No. 15, Jan. 6, 2026, Docket No. 25-08-05, Att. 2, p. 27.

In Section A of its January 13, 2026 ruling on Motion No. 15, the Authority directed the Program Administrators to implement a clawback mechanism for the enrollment incentive where participants disenroll from the ESS Program prior to the expiration of their 10-year term. Motion No. 15 Ruling, Jan. 13, 2026, Docket No. 25-08-05, p. 2.

The Authority determined that, although the enrollment incentive under Construct 5 is not conditioned on active dispatch participation, it is premised on continued participation in the ESS Program over the 10-year enrollment term. Id. Specifically, allowing a participant to retain the full enrollment incentive despite early disenrollment could undermine the structure and intent of Construct 5 by creating a potential incentive to enroll solely to obtain the upfront payment without delivering sustained ratepayer benefits. Id.

The ESS Program Administrators objected and filed a motion for reconsideration pursuant to General Statutes § 16-9. Motion No. 16, Jan. 21, 2026, Docket No. 25-08-05, p. 2. The ESS Program Administrators raised concerns regarding the feasibility and implementation of an enrollment incentive clawback requirement, including administrative burden and cost, the potential for customers to be subject to clawbacks due to circumstances beyond their control (such as manufacturer bankruptcy), and uncertainties associated with customer relocation or transfer of battery ownership. Id., pp. 3-4. The ESS Program Administrators requested that the issue be deferred to the Year 6 annual ESS Program review to allow for broader stakeholder input. Id., p. 4.

In light of these concerns, the Authority stayed Section A of its Motion No. 15 Ruling and indicated its intent to revisit the issue during the Year 6 annual ESS Program review. Motion No. 16 Ruling, Jan. 29, 2026, Docket No. 25-08-05, p. 3. The Authority further clarified that the absence of a clawback provision in the Year 5 Decision reflected a determination specific to dispatch participation requirements, rather than continued enrollment in the ESS Program. Id., p. 2; Year 5 Decision, pp. 14–15.

Accordingly, the Authority sought stakeholder input on whether an enrollment incentive clawback should be implemented such that, if a project disenrolls prior to the conclusion of its 10-year enrollment term, a prorated portion of the enrollment incentive must be repaid. Notice, June 16, 2026, p. 2. For example, a project that disenrolls after one year could be required to return 90% of the incentive. Id. Consistent with prior determinations, any clawback could be conditioned solely on continued ESS Program enrollment and not on participation in active dispatch. Id.

2. Stakeholder Comments

Eversource argued that implementing a formal enrollment incentive clawback mechanism would not be a prudent use of customer funds given the limited number of customers expected to enroll in the ESS Program solely to obtain an enrollment incentive before promptly disenrolling. Eversource Comments, July 9, 2026, p. 3. Eversource expressed concern that implementing such a mechanism would impose administrative costs on customers that could exceed any amounts ultimately recovered. Id. Eversource also noted that customers may disenroll before completing their 10-year enrollment term for legitimate reasons beyond their control, including the sale of a home, battery damage or malfunction, or battery original equipment manufacturer (OEM) bankruptcy. Id., pp. 3-4. According to Eversource, applying an enrollment incentive clawback in these circumstances would be inequitable. Id., p. 4. Finally, Eversource argued that battery systems continue to provide resilience benefits to customers regardless of whether they remain enrolled in the ESS Program. Eversource Comments, July 9, 2026, p. 4.

UI raised similar concerns, stating that implementing an enrollment incentive clawback would increase administrative complexity and labor costs, which ultimately would be borne by all ratepayers. UI Comments, July 9, 2026, p. 2. Nevertheless, if the Authority elects to implement such a mechanism, UI recommended establishing a cost-effectiveness threshold to ensure that administrative costs do not materially exceed the expected ratepayer benefits from recovered enrollment incentives. Id. UI also recommended exempting customers whose early disenrollment results from circumstances beyond their reasonable control, including equipment failure not attributable to the customer, OEM or vendor bankruptcy, force majeure events, and property transfers where the original participant no longer controls the battery system. Id., p. 3. In addition, UI recommended limiting any enrollment incentive clawback to residential and commercial customers who both disenroll early and install battery systems exceeding their annual peak demand, to discourage customers from intentionally oversizing battery systems to maximize enrollment incentives under Construct 5. Id. UI concluded that any clawback mechanism should complement, rather than materially complicate, the Construct 5 framework adopted last year and should avoid introducing unnecessary complexity that could reduce customer understanding or participation. UI Comments, July 9, 2026, p. 4.

Similarly, CGB opposed implementing an enrollment incentive clawback for homeowner-owned residential projects, arguing that the administrative costs and adverse impacts on customer participation would outweigh any potential ratepayer benefits. CGB Comments, July 9, 2026, p. 1. CGB argued that an enrollment incentive clawback would create financial uncertainty, particularly for underserved customers who may disenroll for reasons beyond their control, such as relocation, equipment failure, or the need to preserve battery capacity for backup power during outages. Id. According to CGB, the prospect of an enrollment incentive clawback could discourage participation, negatively affect customer perceptions of the Program, and diminish the resilience benefits the ESS Program provides to vulnerable communities. Id. CGB further noted that battery systems continue to provide grid and resilience benefits through backup power and increased solar self-consumption even after a customer disenrolls from the ESS Program. Id., p. 2.

If the Authority nevertheless adopts an enrollment incentive clawback mechanism, CGB recommended limiting its application, where appropriate, to commercial-scale and residential third-party owned (TPO) projects. CGB Comments, July 9, 2026, p. 2. CGB argued that homeowner-owned residential systems present distinct equity and administrative considerations that differ from commercial-scale and residential TPO projects. Id. Finally, CGB noted that customers already have a significant financial incentive to remain enrolled in the ESS Program because early disenrollment results in the loss of ongoing performance incentive payments. Id.

OCC argued that ratepayer-funded enrollment incentives should be conditioned on delivering ratepayer value throughout the full enrollment term for which they were designed. OCC Comments, July 9, 2026, p. 2. According to OCC, an enrollment incentive clawback serves two purposes: recovering incentive funds when customers disenroll early and deterring opportunistic disenrollment, thereby preserving the ESS Program's cost-effectiveness. Id. OCC argued that these ratepayer protection benefits outweigh the administrative costs of implementing a clawback mechanism and supported an equal prorated repayment schedule. Id., p. 3.

OCC nevertheless urged the Authority to adopt narrowly tailored exemptions for circumstances genuinely beyond a participant's control. Id. OCC recommended that any such exemptions require affirmative documentation, place the burden of proof on the participant seeking relief, and not undermine the overall clawback framework. OCC Comments, July 9, 2026, p. 3. OCC further argued that repayment responsibility should generally rest with the party that received and benefited from the enrollment incentive while accounting for which party had control over the event leading to disenrollment. Id. OCC also recommended applying any outstanding performance incentive payments toward satisfaction of an enrollment incentive clawback before seeking additional repayment. Id., p. 4. Lastly, although OCC supported applying a clawback across all customer classes, it acknowledged that a *de minimis* threshold may be appropriate where administrative costs would be disproportionate to the amount recoverable from the smallest residential participants.[3] Id.

The Alliance for Climate Transition (ACT), the Solar Energy Industries Association (SEIA), and the Coalition for Community Solar Access (CCSA; collectively, the Energy Storage Stakeholders) argued that the administrative costs of implementing an enrollment incentive clawback would likely exceed the value of any recovered funds, would not effectively deter early disenrollment, and would primarily affect customers whose disenrollment resulted from circumstances beyond their control. Energy Storage Stakeholder Comments, July 9, 2026, p. 2. The Energy Storage Stakeholders asserted that the decision to not institute an enrollment incentive clawback in the prior annual review represented a significant program design improvement that was expected to increase participation in and performance of the ESS Program. Id., p. 2.

[3] In its second set of written comments, recognizing the lower enrollment incentive available through Construct 5 and the administrative complexities associated with enforcing the clawback, OCC revised its position and stated that it did not oppose limiting the clawback mechanism to commercial priority customers and residential TPO systems. OCC Comments, Aug. 28, 2026, p. 2.

The Energy Storage Stakeholders further argued that administering an enrollment incentive clawback would require significant resources to monitor disenrollment, calculate repayment amounts, coordinate with customers, OEMs, and third parties that received enrollment incentives, and collect repayment, potentially causing administrative costs to exceed any recovered funds. Id. The Energy Storage Stakeholders also contended that introducing repayment risk, including risks associated with manufacturer bankruptcy, customer relocation, or changes in battery ownership, would discourage customers from participating in the ESS Program. Id., p. 3. According to the Energy Storage Stakeholders, early disenrollment is expected to be rare because customers already have a strong financial incentive to remain enrolled, as the loss of a single year of performance incentive payments typically exceeds the enrollment incentive for most battery systems. Energy Storage Stakeholder Comments, July 9, 2026, p. 3. Nevertheless, if the Authority adopts an enrollment incentive clawback, the Energy Storage Stakeholders recommended applying it only to the entity that received the enrollment incentive and calculating the repayment amount on a prorated basis for the remaining enrollment term. Id.

The Connecticut Solar and Storage Association (ConnSSA) opposed any enrollment incentive clawback that would hold installers or contractors responsible for circumstances beyond their control, including a customer's decision to disenroll from the ESS Program. ConnSSA Comments, July 9, 2026, pp. 1-2. ConnSSA argued that the Construct 5 framework already substantially shifted customer compensation from upfront incentives to performance-based payments, thereby reducing ratepayer risk by tying most compensation to actual grid performance. Id., p. 1. According to ConnSSA, a broad enrollment incentive clawback would create customer confusion, discourage ESS Program participation, and increase administrative burden while providing little additional ratepayer protection. Id.

If the Authority nevertheless adopts an enrollment incentive clawback, ConnSSA recommended limiting repayment responsibility to the party that owns the battery system, receives the enrollment incentive, controls the enrollment decision, or affirmatively causes the project to be removed from the ESS Program. Id., p. 2. ConnSSA argued that contractor liability should be limited to contractor-caused issues, such as installing ineligible equipment, failing to complete required project documentation, or other pre-completion noncompliance within the contractor's control. ConnSSA Comments, July 9, 2026, p. 2. Accordingly, ConnSSA urged the Authority to distinguish between contractor-caused noncompliance and customer-controlled post-completion conduct if it implements an enrollment incentive clawback. Id.

CPower did not oppose a prorated enrollment incentive clawback for residential and commercial customers that disenroll before completing their 10-year enrollment term. CPower Comments, July 9, 2026, p. 2. CPower argued that battery projects are economically dependent on continued participation in the ESS Program and, therefore, are unlikely to disenroll before the end of their enrollment term except in cases of catastrophic battery damage. Id. In those circumstances, CPower argued that recovering a prorated share of the enrollment incentive would be appropriate because ratepayers would no longer receive the intended benefits from the battery system. Id. CPower

further recommended assessing any clawback against the entity receiving ESS Program payments at the time the clawback is imposed, rather than the entity that received payments when the project originally enrolled, to ensure repayment responsibility rests with the party then responsible for the battery system while reducing administrative complexity. Id.

Earthlight cautioned against adopting an overly broad enrollment incentive clawback that would apply to customers who disenroll before completing their 10-year enrollment term, arguing that doing so would create unnecessary negative customer experiences and discourage future ESS Program participation. Earthlight Comments, July 9, 2026, p. 2. Earthlight noted that most early disenrollments result from circumstances beyond a customer's control, such as OEM bankruptcy. Id. Earthlight further argued that the Construct 5 framework already adequately protects ratepayers by reducing the upfront enrollment incentive and shifting a larger share of compensation to performance-based payments, thereby ensuring that customers receive most ESS Program incentives only if they continue participating in seasonal dispatch events. Id., p. 3.

3. Authority Analysis

An enrollment incentive clawback provision is necessary to ensure that ratepayer-funded enrollment incentives remain reasonably aligned with the benefits the ESS Program is intended to provide over a participant's enrollment term. Although the enrollment incentive under Construct 5 is substantially smaller than the upfront incentive offered under the prior passive dispatch structure, it is not de minimis. The enrollment incentive may be $3,900 or more for grid-edge residential customers and may be substantially higher for commercial priority customers, depending on system size. See Program Administrator Corresp., Aug. 3, 2026, pp. 5–6. Without a clawback provision, a system owner could disenroll from the ESS Program shortly after receiving the enrollment incentive while retaining the full payment. Such an outcome would allow a participant to receive a ratepayer-funded benefit without providing the full period of Program participation contemplated by Construct 5 and could reduce the peak reduction, dispatch, and other system benefits expected from the Program, thereby adversely affecting the Program's RIM score.

The Authority recognizes the stakeholder concerns regarding the administrative costs associated with implementing and enforcing a clawback, as well as the potential for customers to disenroll for legitimate reasons beyond their control. Further, Construct 5 has already substantially reduced ratepayer risk by shifting a greater portion of participant compensation from upfront incentives to performance-based payments. Nevertheless, the existing compensation structure does not eliminate the need for a narrowly tailored clawback. The enrollment incentive remains a material payment, and the possibility that a participant could retain the full incentive after prematurely ending their participation creates a risk that is not addressed by the loss of future performance incentive payments alone.

This concern is particularly relevant as TPOs are expected to become increasingly important to the ESS Program as a result of recent changes to the federal investment tax

credit (ITC).[4] TPOs may manage portfolios containing numerous ESS Program customers and, as a result, may have the ability to cause multiple projects to disenroll if they are unable or unwilling to maintain their systems for Program participation as their financial circumstances or business models change. Although the Authority does not conclude that widespread or opportunistic disenrollment by TPOs is inevitable, the potential for a single entity to cause multiple projects to leave the Program presents a material risk to Program deployment and ratepayer benefits. Establishing an enrollment incentive clawback mechanism before such circumstances arise will provide an appropriate safeguard while the Program continues to evolve.

Several participants have raised the concern that it would be unfair to impose a clawback upon customers who must disenroll from the Program for circumstances outside their control. The Authority disagrees. The purpose of the clawback is not to penalize participants for wrongdoing. Rather, the clawback is an adjustment intended to ensure that ratepayer-funded benefits actually materialize. The premise and goal of the ESS Program as a whole is that ratepayer-funded incentives will ultimately derive grid benefits that exceed the financial value of the incentives provided. Where Program participants are unable to continue their participation – for any reason – the value proposition is disrupted and the justification for ratepayer contributions are nullified. The clawback is therefore intended to address this shortfall by aligning the value of the incentives retained with the benefits actually delivered.

Accordingly, an enrollment incentive clawback shall be implemented for all new system owners enrolling in the ESS Program, effective when the revised Program Manual is approved following this Decision. A system owner may not disenroll from the ESS Program until the applicable prorated clawback amount has been collected in full. The clawback shall be calculated on a prorated basis according to the portion of the system owner's 10-year enrollment term remaining at the time of disenrollment. For example, if a system owner disenrolls one year into its 10-year enrollment term, the enrollment incentive clawback shall equal 90% of the original enrollment incentive. This approach appropriately balances the interests of ratepayers and participants by recognizing that a participant that remains enrolled for a portion of the required term has provided some of the benefits contemplated by the enrollment incentive, while ensuring that the participant does not retain the full incentive after shortening their participation period.

The clawback shall apply prospectively to new system owners only. System owners that enrolled in the ESS Program before the effective date of the revised Program Manual shall be grandfathered under the requirements applicable at the time of their enrollment. Applying a new repayment obligation to existing system owners would be inequitable where those owners enrolled in the Program and accepted the requirements in effect at the time of their enrollment.

[4] Unlike TPO systems, homeowner-owned batteries are no longer eligible for ITC benefits after 2025.

Further, certain implementation provisions are necessary to ensure that the clawback mechanism itself does not impose costs on ratepayers that exceed the amounts reasonably expected to be recovered or unnecessarily discourage Program participation.[5]

First, to minimize administrative and collection costs, the Program Administrators shall apply any remaining unpaid performance incentive amounts owed to the system owner toward satisfaction of the enrollment incentive clawback before seeking additional repayment. This approach is consistent with the methodology previously established by the Authority for recovery of upfront incentive clawbacks. See Year 5 Decision, p. 31. If the amount of unpaid performance incentives is insufficient to satisfy the clawback, the Program Administrators shall contact the system owner and provide an opportunity for voluntary repayment of the remaining amount. If voluntary repayment is unsuccessful, the Program Administrators may pursue additional collection measures, including legal action or referral to a collection agency, provided that the Program Administrators reasonably determine that the expected amount to be recovered exceeds the costs of pursuing such collection. This requirement will ensure that ratepayers do not incur collection costs that are or greater than the amount of the enrollment incentive expected to be recovered.

Second, although the enrollment incentive clawback obligation shall apply to all new system owners, the Program Administrators shall pursue involuntary collection through legal action or a collection agency only when the system owner is a TPO or commercial customer. The amounts recoverable from individual residential customers are more likely to be insufficient to justify the costs associated with formal collection efforts.[6] Limiting formal collection efforts for residential customers will also reduce the potential for the clawback mechanism to create a disproportionate financial deterrent to residential participation in the ESS Program. This limitation does not eliminate the clawback obligation for residential system owners; rather, it appropriately limits the circumstances in which ratepayer-funded resources may be expended to pursue collection of a relatively small amount.

Third, the enrollment incentive clawback shall apply solely to the current system owner. The system owner is the appropriate party to bear responsibility for the clawback because the system owner is the entity that enters into the ESS Program and accepts the associated Program requirements. This approach appropriately aligns repayment responsibility with the party that controls the decision to remain enrolled in the ESS

[5] To the extent that the process described in the Program Administrators' response to Interrogatory CAE-9 is consistent with the determinations herein, the Program Administrators may implement the enrollment incentive clawback in accordance with that process, provided that all provisions set forth herein are also followed.

[6] The Program Administrators estimated that, excluding legal costs, pursuing clawbacks could result in administrative costs of approximately $707 to $1,414 per project, based on the labor hours associated with these efforts. Program Administrator Interrog. Resp. CAE-9, p. 3. Nevertheless, where a TPO seeks to disenroll multiple projects or its entire fleet, the Authority expects that economies of scale would reduce the per-project labor costs associated with pursuing the applicable clawbacks.

Program while avoiding the unintended assignment of liability to parties that may have no control over a customer's decision to disenroll.

Finally, narrowly tailored exceptions are appropriate where early disenrollment results from circumstances that are genuinely beyond the system owner's reasonable control. Accordingly, the Program Administrators shall waive the enrollment incentive clawback when, after reviewing the circumstances of the disenrollment, they determine that the system owner did not cause or could not reasonably have prevented the event resulting in disenrollment. Such circumstances may include, but are not limited to, qualifying force majeure events and battery malfunction or failure attributable to the manufacturer, contractor, or other party outside the system owner's reasonable control. The exceptions shall be applied narrowly and shall not extend to voluntary disenrollment or circumstances that could reasonably have been prevented by the system owner.

These provisions appropriately balance ratepayer protection with the need to maintain customer participation and minimize unnecessary administrative costs. The resulting mechanism preserves the Authority's determination that the enrollment incentive is intended to support sustained participation over the 10-year enrollment term, while avoiding a collection process that could impose disproportionate costs on ratepayers or create an unreasonable barrier to ESS Program participation.

D. FTM STORAGE TARIFF

1. Background

During the Year 2 annual ESS Program review, the Authority convened an FTM Storage Working Group to develop a comprehensive set of FTM storage tariff and incentive design proposals for Authority consideration. Year 2 Decision, p. 39.

Following that effort, the EDCs each developed Wholesale Distribution Access Tariffs (WDATs) to enable FTM storage resources to interconnect with the distribution system and participate in wholesale markets. EDC Compliance, Docket No. 22-08-05, Dec. 29, 2023. The EDCs subsequently filed their respective WDATs with the Federal Energy Regulatory Commission (FERC), which approved each proposal.[7]

However, the record developed in Docket No. 25-02-14, Renewable Energy Tariff Programs Successor Study, indicated that the WDAT framework is limited in scope. Specifically, the WDATs facilitate the sale of energy into wholesale markets but do not provide a mechanism for FTM storage resources to purchase energy from the EDCs at retail (i.e., the WDAT functions as a one-way tariff). PURA Corresp., Feb. 27, 2026, Docket No. 25-02-14, p. 106. In that proceeding, SEIA and New Leaf advocated for the development of a bidirectional time-of-use (TOU) retail rate applicable to standalone FTM storage. New Leaf Corresp., Sept. 23, 2025, Docket No. 25-02-14, p. 8; SEIA Comments, Sept. 10, 2025, Docket No. 25-02-14, p. 4. UI further noted that standalone storage is not currently eligible to participate in any existing retail TOU tariffs in Connecticut as a

[7] See FERC dockets ER24-3153-000 and ER24-2939, available at: https://elibrary.ferc.gov/eLibrary/search.

distinct resource class. UI Interrog. Resp. CAE-49, Docket No. 25-02-14, p. 2. Although the WDATs approved by FERC include TOU constructs, those provisions apply solely to wholesale transactions and do not establish retail rate structures. Id.

In light of these limitations, the Authority expressed interest in directing the EDCs, in a future proceeding, to develop retail TOU rates for standalone FTM storage to support its effective integration and operation. PURA Corresp., Feb. 27, 2026, Docket No. 25-02-14, p. 106.

Accordingly, the Authority sought stakeholder input on the appropriate process for developing retail TOU rates for standalone FTM storage, as well as the key design features such rates should include. Notice, June 16, 2026, pp. 3–4.

2. Stakeholder Comments

Eversource argued that establishing a retail TOU rate for FTM storage presents a fundamental legal issue. Eversource Comments, July 9, 2026, p. 6. Specifically, Eversource asserted that both the purchase of electricity by, and the sale of electricity from, a stand-alone FTM storage resource are facially FERC-jurisdictional wholesale transactions. Id. According to Eversource, because a stand-alone FTM storage resource has no retail load other than station power, the purchase of electricity for charging constitutes a wholesale transaction subject to FERC jurisdiction. Id. Although Eversource asserted that FERC has indicated that commingling retail station power load with wholesale load may render the entire transaction state-jurisdictional, Eversource maintained that, even if the Authority could lawfully establish a retail rate for electricity purchased by stand-alone FTM storage resources, it could not establish a rate governing power sales from those resources to an EDC unless the EDC itself consumed the electricity. Id. Eversource further argued that stand-alone FTM storage resources are not qualifying facilities under the Public Utility Regulatory Policies Act (PURPA), and, therefore, cannot be required to sell wholesale energy to an EDC at a state-established rate. Eversource Comments, July 9, 2026, p. 6.

Eversource also questioned the economic viability of a bundled retail TOU rate for stand-alone FTM storage. Id., pp. 6–7. Eversource argued that a retail TOU rate would necessarily include transmission, distribution, and other non-bypassable charges and, therefore, would generally exceed the wholesale rates at which FTM storage resources could otherwise procure unbundled energy services. Id. As a result, Eversource questioned why a stand-alone FTM storage resource with no on-site load would purchase electricity under a retail tariff rather than at wholesale rates unless the retail TOU rate substantially discounted those charges. Id., p. 7. Accordingly, Eversource concluded that, absent a stakeholder proposal addressing these legal and economic concerns, there is no basis for initiating a stakeholder process to develop a retail TOU rate for FTM storage. Eversource Comments, July 9, 2026, p. 7.

UI also opposed considering a retail TOU rate for FTM storage in this proceeding, although for reasons different from those raised by Eversource. UI acknowledged that the current WDAT allows stand-alone FTM storage resources to participate in wholesale markets but does not provide a mechanism for those resources to procure charging

energy at retail. UI Comments, July 9, 2026, p. 5. According to UI, this structural gap will affect the Authority's consideration of time-varying rates across multiple proceedings and may prevent FTM storage resources from responding efficiently to consistent time-based charging and discharging price signals. Id., pp. 5–6.

UI recommended that the Authority maintain a clear distinction between the ESS Program and stand-alone FTM storage because those resources provide different services than BTM storage participating in the ESS Program. Id., p. 6. In UI's view, incorporating FTM storage into the ESS Program would be inconsistent with the Program's intended design and create both administrative and jurisdictional complications. Id. Instead, UI recommended addressing FTM storage through a separate regulatory framework, such as a non-wires solutions (NWS) program or distribution system planning process. UI Comments, July 9, 2026, pp. 7–8.

UI further argued that any retail TOU rate developed for FTM storage should be revenue neutral, grounded in principles of cost causation, and limited to establishing how stand-alone FTM storage resources procure electricity at retail. Id. UI also recommended that any such tariff exclude ratepayer-funded incentives to avoid duplicative compensation with wholesale market revenues. Id., p. 8. Finally, UI maintained that an NWS framework is better suited to procure FTM storage because those resources are deployed to address specific distribution system needs and can therefore be evaluated through a planning and procurement process focused on reliability, system performance, and cost-effectiveness. Id. While a retail TOU tariff may influence charging behavior, UI argued that it cannot substitute for a planning-based procurement process designed to resolve identified distribution system constraints. UI Comments, July 9, 2026, p. 8.

Conversely, OCC emphasized that any future retail TOU rate for FTM storage should closely reflect principles of cost causation to provide accurate price signals that encourage efficient charging and discharging behavior. OCC Comments, July 9, 2026, p. 5. OCC also argued that a more granular TOU structure would better maximize peak demand reductions and the resulting ratepayer benefits. Id. In addition, OCC expressed support for a load reducer model under which FTM storage resources would forego wholesale market participation in exchange for sharing the value of measured load reductions through reduced energy, capacity, and transmission costs. Id. According to OCC, incorporating avoided transmission costs into a retail TOU tariff would produce a more complete price signal and promote an efficient level of FTM storage deployment that reflects the full value provided to ratepayers. Id.

OCC nevertheless argued that the avoided costs associated with FTM storage must first be demonstrated through a rigorous avoided cost study showing that those benefits exceed the costs of facility operation and tariff implementation before the Authority establishes a new tariff. OCC Comments, July 9, 2026, p. 5. OCC also noted that the metering infrastructure required to support a retail TOU rate raises important cost and standardization considerations. Id., p. 6. Accordingly, OCC recommended that the Authority require the EDCs to identify any necessary metering upgrades for FTM storage participants and specify who would bear those costs before finalizing a tariff. Id.

OCC further recommended that any retail TOU tariff precisely define eligible FTM storage resources to avoid overlap with hybrid or co-located resources that may have different cost structures and operational characteristics. Id. At a minimum, OCC recommended that the tariff address: (a) whether co-located generation affects eligibility for the retail TOU rate; (b) whether a minimum storage capacity threshold is necessary to ensure cost-effectiveness; and (c) how eligibility would interact with ESS Program participation for resources that could otherwise qualify under both frameworks. OCC Comments, July 9, 2026, p. 6.

Lastly, OCC recommended a phased approach to developing a retail TOU rate for FTM storage, beginning with a technical working group to address metering requirements, WDAT alignment, and eligibility criteria, followed by circulation of a straw proposal for stakeholder comment and an EDC compliance filing implementing the Authority's approved rate design. Id. OCC opposed any expedited schedule that would limit meaningful stakeholder participation on issues with significant long-term ratepayer cost implications. Id. OCC also emphasized that, while revenue neutrality is an important ratepayer protection, it does not resolve cost allocation issues, including whether any costs or benefits associated with FTM storage participation would be allocated equitably among customer classes. Id.

The Energy Storage Stakeholders argued that the WDAT is inadequate for developers because it provides no corresponding mechanism to capture distribution-system benefits, provides wholesale market revenues that are insufficient to support development, and provides less certain revenue streams that cannot be relied upon for project financing. Energy Storage Stakeholder Interrog. Resp. CAE-41, pp. 1–2. They further argued that the value of a bidirectional retail TOU tariff lies in integrating charging and discharging under a single tariff, such that price signals for both withdrawing and injecting electricity minimize system costs and maximize system benefits while supporting the efficient operation of FTM storage resources. Energy Storage Stakeholder Comments, July 9, 2026, pp. 4–5. The Energy Storage Stakeholders also argued that the Authority need not develop such a tariff from first principles because the EDCs' existing WDAT tariffs provide a proven framework that can be adapted for a retail TOU rate. Id., p. 5.

With respect to tariff design, the Energy Storage Stakeholders proposed charging and crediting energy at higher prices during periods of system stress and at lower prices during periods of lower system demand. Id. For the energy supply component, they recommended mirroring wholesale locational marginal prices (LMPs), with hourly purchases billed at LMP and hourly exports credited at LMP. Id. Consistent with the WDAT, they also recommended excluding volumetric distribution delivery charges, limiting volumetric charges to energy supply and any non-bypassable charges determined through a threshold analysis. Energy Storage Stakeholder Comments, July 9, 2026, p. 5.

The Energy Storage Stakeholders further recommended aligning local distribution and transmission charges with the WDAT by assessing those charges on a demand, rather than volumetric, basis because the EDCs incur those costs based on peak

demand. Id. They also proposed allowing FTM storage resources to receive negative demand charges, or compensation, when discharging during monthly ISO New England system peaks, citing similar treatment in Illinois and arguing that such an approach would pass measurable transmission cost savings through to Connecticut ratepayers. Id., pp. 5–6.

The Energy Storage Stakeholders emphasized that each grid service or system benefit should be compensated only once and suggested preserving, as part of the stakeholder process, the question of whether EDC-administered compensation should be available for capacity contributions. Id., p. 6. They further noted that any retail TOU tariff should be developed using the EDCs' PURA-approved retail revenue requirements and cost-of-service studies, rather than the FERC Form 1 methodology used to develop the WDAT. Energy Storage Stakeholder Comments, p. 6.

With respect to non-bypassable charges, the Energy Storage Stakeholders argued that applying volumetric public policy charges to electricity used for charging storage systems results in double payment because those charges are assessed both when the storage resource charges and again when the electricity is ultimately delivered to the end-use customer. Id. Accordingly, they recommended that the Authority direct the EDCs to evaluate alternative approaches, such as demand-based or net-throughput methodologies, during tariff development. Id. According to the Energy Storage Stakeholders, no other design issue will have a greater impact on whether a revenue-neutral retail TOU rate is commercially viable. Id.

The Energy Storage Stakeholders also recommended that the cost of charging during lower-priced periods be meaningfully less than the compensation available for discharging during periods when electricity provides the greatest value to the grid. Energy Storage Stakeholder Comments, p. 6. They further argued that the retail TOU tariff and the WDAT should use compatible peak period definitions to avoid conflicting price signals. Id., p. 7. With respect to implementation, the Energy Storage Stakeholders recommended maintaining simple metering requirements because, under a purely retail framework, all energy measured at the meter would constitute retail service. Id. They also proposed limiting eligibility to stand-alone, distribution-connected FTM storage resources without establishing a minimum size threshold, arguing that this approach directly addresses the gap identified in Docket No. 25-02-14. Id.

Finally, the Energy Storage Stakeholders recommended that the Authority establish a robust stakeholder process to resolve the remaining technical issues associated with developing a retail TOU tariff. Energy Storage Stakeholder Comments, p. 7. They urged the Authority to adopt a clear schedule with defined milestones that provides sufficient time for stakeholder engagement while maintaining steady progress toward implementation and recommended completing the tariff development process by March 31, 2027. Id., p. 8.

3. Authority Analysis

a. Overview

There is insufficient information or quantitative data to establish the parameters or requirements of a bidirectional retail TOU tariff specifically tailored to standalone FTM storage. However, the existing regulatory framework does not fully address the unique characteristics of FTM storage, warranting further investigation into whether, and under what circumstances, a new retail tariff could facilitate the efficient deployment and operation of FTM storage while providing commensurate benefits to Connecticut ratepayers. Accordingly, the Authority finds it appropriate to reestablish the FTM Storage Working Group that developed the original WDAT framework to further investigate these issues and develop a comprehensive tariff framework for the Authority's consideration.

b. Regulatory Gap and Need

The record does not indicate any current deployment of TPO FTM storage in Connecticut, notwithstanding the Legislature's express recognition of FTM storage in General Statutes § 16-243ee(c). DEEP selected a 200 MW FTM storage project in 2024; however, that project did not ultimately[8] successfully negotiate a contract with the EDCs. See PURA Corresp., Docket No. 25-02-14, p. 97.

At the same time, Connecticut does not currently have a retail tariff specifically tailored to standalone FTM storage. UI interrog. Resp. CAE-49, Docket No. 25-02-14, p. 2. Although the WDAT framework provides FTM storage resources with access to the distribution system for participation in wholesale markets, the WDAT does not establish a retail mechanism through which a standalone FTM storage resource can procure charging energy from an EDC at retail. PURA Corresp., Docket No. 25-02-14, p. 106. Stakeholders have also indicated that wholesale energy price arbitrage and other wholesale market services under the existing WDAT framework may not, by themselves, provide sufficient or sufficiently predictable revenue to support FTM storage development or financing. Energy Storage Stakeholder Interrog. Resp. CAE-41, pp. 1–2. This regulatory and economic gap warrants further examination, particularly given the continued stakeholder interest in FTM storage demonstrated in this proceeding, prior ESS annual reviews, and Docket No. 25-01-15, Front-of-the-Meter Storage Program.

Furthermore, the Authority is considering time-differentiated compensation for successor solar programs in Docket No. 26-06-04, Implementation of Clean Energy Successor Programs. See Notice of Request for Written Comments, July 28, 2026, pp. 1–2. Non-residential state, agricultural, and municipal (SAM) projects are virtual net-metered FTM solar resources, and community solar projects are FTM by design. To the extent successor solar programs provide time-differentiated compensation, pairing FTM solar resources with storage could allow the resources to shift the timing of energy injections to periods when such energy provides greater value to the electric system and, therefore, potentially increase the value of the resources to Connecticut ratepayers.

[8] See https://www.dpuc.state.ct.us/DEEPEnergy.nsf/c6c6d525f7cdd1168525797d0047c5bf/ec10b8406c78d86885258e7500525270/$FILE/2026%20Procurement%20Plan%20Update.pdf (page 3).

Because the underlying solar resources are FTM, storage paired with those resources would generally also need to be FTM to provide that capability. Accordingly, establishing an appropriate framework for FTM storage could help facilitate the implementation of time-differentiated compensation under successor solar programs and may enable those programs to better capture the potential system value of FTM solar generation.

c. Ratepayer Benefits

In addition to facilitating the integration and operation of FTM solar resources, FTM storage has the potential to provide multiple benefits to non-participating ratepayers. Unlike a conventional incentive program that requires participating ratepayers to fund the deployment of storage resources, a properly designed bidirectional retail TOU tariff could compensate FTM storage only for measurable services or benefits provided to the distribution system. For example, appropriately located and operated FTM storage could reduce demand during system or distribution peaks, thereby reducing the EDCs' costs associated with serving peak demand; reduce the EDCs' allocation of Regional Network Service costs; and avoid or defer distribution system investments where storage can reliably address an identified system constraint. These benefits could accrue to Connecticut ratepayers generally, including customers that do not own or participate in an FTM storage resource. To the extent the value of these benefits exceeds the costs of the tariff, FTM storage could therefore provide a net benefit to Connecticut ratepayers without requiring non-participating customers to subsidize the deployment of participating resources or provide an upfront incentive.

d. Statutory Authority

The Legislature previously provided the Authority with explicit authority to develop an FTM storage program and subsequently rescinded that authority through Public Act 25-173, § 55, which amended General Statutes § 16-243ee. The Legislature also assigned DEEP a role in the procurement of storage resources. General Statutes § 16-243dd. Accordingly, the Authority must carefully consider the scope of its existing statutory authority and the Legislature's allocation of responsibilities between the Authority and DEEP before establishing any FTM storage-specific tariff framework. At the same time, the Authority retains broad distribution ratemaking authority pursuant to General Statutes §§ 16-19 and 16-19e.

Accordingly, the Authority finds that further investigation is warranted. Developing a detailed tariff framework will allow the Authority to better distinguish between a retail rate structure addressing the costs and benefits associated with distribution-connected FTM storage and a programmatic mechanism for procuring or subsidizing FTM storage resources. It will also allow the Authority to identify which aspects of a potential framework could be implemented under existing authority and whether additional legislative authorization would be appropriate or necessary. The Authority therefore considers the development of a well-supported tariff framework to be a necessary precursor to any future determination regarding implementation.

e. FERC vs PURA Jurisdiction

As previously discussed, Eversource raised concerns that an FTM storage retail tariff can infringe on FERC's jurisdiction to regulate wholesale electric rates. Particularly, Eversource cautioned that an FTM retail tariff that enables an FTM storage resource to purchase power to charge and subsequently sell its output to an EDC at a retail rate would constitute a FERC-jurisdictional transaction. Eversource Comments, pp. 5–6, July 9, 2026. Moreover, Eversource asserted that stand-alone FTM resources are not permitted to sell power to the EDCs under PURPA, which provides the sole means of compelling EDCs to purchase wholesale energy set by states. Id., p. 6.

Eversource's comments capture the complexity of FERC and state jurisdictional issues pertaining to the deployment and operation of FTM energy storage resources. Thus, any retail tariff for FTM storage must be carefully crafted to capture distribution-level benefits while avoiding incursions into FERC's jurisdiction over wholesale transactions. While the Authority must evaluate and adjudicate any jurisdictional issues pertaining to a specific FTM storage tariff in a ratemaking proceeding, the Authority briefly summarizes the relevant jurisdictional issues here to inform the Working Group's deliberations.

Under the Federal Power Act (FPA), FERC has exclusive jurisdiction over the sale of electricity as a matter of interstate commerce, while the regulation of retail electricity sales is reserved for the states, no matter the effects the state's regulatory actions have on wholesale electricity rates. 16 U.S.C. § 824; F.E.R.C. v. Electric Power Assn, 577 U.S. 260, 280 (2016). Within the context of energy storage resources, FERC issued Order No. 841, which set forth the limits of FERC's jurisdiction of such resources in the wholesale market. 162 FERC ¶ 61,127, Docket Nos. RM16-23-000; AD16-20-000; Order No. 841, Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators (Feb. 15, 2018) (Order No. 841). Specifically, FERC held that "an electric storage resource that injects electricity back to the grid for purposes of participating in an RTO/ISO market engages in the sale of electric energy at wholesale in interstate commerce."[9] Order No. 841, p. 27. Therefore, under Order No. 841, a potential retail tariff cannot compensate FTM storage resources for participation in wholesale energy or ancillary-service markets or, in other words, where the energy from such resources is sold into the wholesale market.

Importantly, FERC delineated between the sale of electric energy at wholesale from transactions that do not involve the sale of electricity at wholesale, such as those compensating storage resources as demand response resources.[10] Order No. 841, p.

[9] FERC defines an "electric storage resource" as a resource capable of receiving electric energy from the grid and storing it for later injection of electric energy back to the grid. Order No. 841, p. 1. FERC further clarified that a resource "capable of later injecting electricity back to the grid" means a storage resource both physically designed and configured to do so and is contractually permitted to do so.

[10] A "demand response resource" is defined as a "resource capable of providing demand response." 18 Code of Federal Regulations (CFR) § 35.28(b)(5). "Demand response" is defined as a "reduction in the consumption of electricity by customers from their expected consumption in response to an increase in the price of electric energy or to incentive payments designed to lower consumption of electric energy." 18 C.F.R. § 35.28(4).

28, n. 53. Therefore, a retail tariff may compensate an energy storage resource for products that do not include the sale of electric energy in wholesale energy or ancillary-services markets, such as load reducer benefits and other distribution-level benefits, so long as compensation is not intertwined with a wholesale transaction related to the sale of electric energy into wholesale energy or ancillary-service markets. In sum, under such a construct, load reducer and other distribution-level benefits do not compensate the resource for the sale of electricity into the wholesale market and are separate and distinct from such transactions; therefore, they do not constitute a sale of electricity in interstate commerce under the FPA.

Notably, the Authority and Eversource agree that a transaction in which the resources are not being compensated for buying and selling energy as a commodity or are otherwise compelling the EDCs to purchase energy are PURA jurisdictional. Tech Meeting Tr., Aug. 7, 2026, 104:1–16; 105: 2–13; 106:9–19; 109:9-19. Accordingly, any potential bidirectional retail TOU tariff should be designed to compensate FTM storage for identifiable distribution-level services or benefits within the Authority's jurisdiction, rather than to regulate or compensate wholesale transactions subject to FERC jurisdiction, such as wholesale energy arbitrage transactions. Specifically, compensation for distribution-level benefits should be structured separately from wholesale energy and ancillary-service transactions to avoid duplicative compensation.

f. Additional Tariff Design Considerations

Any future FTM storage tariff must be designed to provide benefits to Connecticut ratepayers that exceed the costs associated with the tariff. A retail tariff developed through this process must not function as an incremental deployment incentive or otherwise provide compensation unrelated to identifiable costs or benefits to the electric system simply to induce the construction of FTM storage. Rather, the purpose of a potential tariff would be to establish appropriate price signals and compensation mechanisms for identifiable distribution-level costs and benefits associated with the operation of eligible FTM storage resources. As discussed above, such benefits could include, but need not be limited to, shifting charging or discharging away from constrained periods, reducing the EDCs' allocation of Regional Network Service costs through reductions in relevant system peaks, and avoiding or deferring distribution system investments.

Further, a potential tariff should be evaluated using a quantifiable ratepayer-impact framework that demonstrates a net benefit to Connecticut ratepayers. To the extent practicable, the CT-RIM methodology used to evaluate the ESS Program should be applied to proposed tariff parameters to promote consistency in the methodologies used to assess Connecticut's energy storage programs. Any tariff ultimately recommended for the Authority's consideration should demonstrate a CT-RIM score of at least 1.4, consistent with the ratepayer-protection threshold applied in the ESS Program.

A potential FTM storage tariff would also need to be carefully coordinated with the existing WDAT framework and wholesale market participation. Specifically, the interactions between a potential retail tariff, the WDAT, and wholesale market participation

are relevant to tariff design, including to prevent conflicting price signals or duplicate compensation for the same service or benefit.

If a retail tariff is intended to provide sufficient economic value to influence FTM storage operation, a bidirectional structure warrants consideration. Such a structure could establish time-varying prices for charging and compensation for discharging during periods when the resource provides greater value to the distribution system.

g. Working Group and Next Steps

The current record is insufficient to establish these parameters through this proceeding. Significant technical, economic, rate-design, and operational, and legal issues remain regarding, among other things, the valuation of distribution-level benefits, appropriate eligibility requirements, metering, WDAT interaction, non-bypassable charges, cost allocation, location-specific value, and coordination with wholesale market participation. These issues warrant substantial stakeholder expertise and engagement before the Authority considers a specific tariff for adoption. Notably, both EDCs expressed openness to, and identified potential value in, examining these issues through a working-group structure similar to the original FTM Storage Working Group. Tech Mt'g Tr., Aug. 7, 2026, 86:12–89:11.

Accordingly, the Authority reestablishes the FTM Storage Working Group that previously examined FTM storage and informed the development of the WDAT framework. CGB, as an ESS Program administrator with experience in clean energy policy and stakeholder engagement, shall lead the Working Group.[11] Subject to future prudence review, costs incurred by CGB in connection with this initiative shall be eligible for consideration for cost recovery in future RAM proceedings and shall be submitted as a specific line item in CGB's annual RAM filing. CGB shall invite, at a minimum, the EDCs, DEEP, OCC, ACT, SEIA, CCSA, and all members of the original FTM Storage Working Group to participate in the process. See EDC Compliance, Docket No. 22-08-05, Dec. 29, 2023, WG Report, p. 19.

CGB shall establish the Working Group no later than March 1, 2027, and shall submit a comprehensive FTM Storage Tariff Report by December 1, 2027. The report shall identify the Working Group's findings and recommendations regarding the feasibility and design of a bidirectional retail TOU tariff for standalone FTM storage and shall identify any issues that may require additional statutory authorization before implementation.

Upon receipt of the FTM Storage Tariff Report, the Authority may initiate a separate proceeding to consider whether to adopt the proposed FTM storage tariff, consistent with the Authority's statutory authority at that time. Any such proceeding will be separate from the ESS annual review dockets because standalone FTM storage presents distinct regulatory, operational, and rate-design considerations and would not constitute an expansion of the ESS Program.

[11] CGB, at its discretion and in recognition of DEEP's role in the deployment of FTM storage in the state, may invite DEEP to participate in a leadership capacity within the Working Group.

At a minimum, the FTM Storage Tariff Report shall address:

1. the appropriate structure and time periods for any bidirectional retail TOU tariff, including whether charging and discharging should be subject to different time-varying rates or credits;
2. the specific distribution-level benefits that could appropriately be recognized through a retail tariff and the methodology for quantifying and attributing those benefits to participating resources;
3. the appropriate compensation mechanism for identified distribution-level benefits, including whether compensation should vary based on time, system conditions, or other relevant characteristics;
4. whether the tariff should provide location-specific compensation for FTM storage resources that can avoid or defer identified distribution system investments and, if so, how any such compensation should be calculated;
5. the appropriate charge structure, including the treatment of transmission, distribution, and non-bypassable charges and whether alternative charge methodologies are necessary to avoid inappropriate or duplicative charges;
6. the appropriate eligibility, sizing, metering, and performance requirements for participating FTM storage resources, including the treatment of co-located resources;
7. how the tariff should interact with the WDAT and wholesale market participation, including appropriate mechanisms to avoid conflicting price signals and duplicate compensation;
8. whether alternative versions of the tariff should be developed to support participation in a subset of wholesale markets (e.g., forward capacity market only);
9. any federal legislation or regulation that explicitly permits or prohibits participation of an FTM storage resource in wholesale markets that takes service on a retail tariff;
10. the appropriate treatment of cost allocation and the potential impacts on participating and non-participating customer classes; and
11. the participant and ratepayer impacts of the proposed tariff, including the PCT and CT-RIM score, using ESS Program methodologies to the greatest extent possible.

h. Conclusion

The reestablishment of the FTM Storage Working Group does not constitute a determination that a particular FTM storage tariff should ultimately be adopted or that the Authority presently has sufficient statutory authority to implement every potential recommendation developed through the Working Group. Rather, the purpose of this process is to develop the technical and economic record necessary for the Authority to make those determinations in a subsequent proceeding or, as appropriate, to identify any additional legislative authorization that may be necessary.

Ultimately, FTM storage may provide benefits to Connecticut's electric system and ratepayers that are not fully reflected through existing wholesale market mechanisms.

The Working Group will provide an opportunity to evaluate those potential benefits rigorously and develop recommendations regarding whether, and under what framework, they could appropriately be reflected in Connecticut's retail rate structure.

E. DATA DASHBOARD

1. Background

The Authority investigated whether additional information should be included on the ESS Program data dashboard, including annual performance incentive payments and identification of the actual annual ISO-NE system peak hour. PURA Interrogatories, June 16, 2026, p. 1.

Eversource and UI supported adding total and average annual performance incentive payments to the dashboard, stating that greater cost transparency would help customers make more informed decisions when selecting battery systems. Eversource Interrog. Resp. CAE-2, p. 1; UI Interrog. Resp. CAE-2, p. 1. UI further noted that making performance payment information publicly available could encourage improved OEM performance. UI Interrog. Resp. CAE-2, p. 1.

CGB similarly supported adding performance incentive payment information, stating that doing so would enhance cost transparency, provide greater visibility into the scale of annual performance-based payments, and provide a more complete understanding of Program costs and participant benefits over time. CGB Interrog. Resp. CAE-2, p. 1. CGB stated that implementation would require obtaining or confirming historical final seasonal performance payments from the EDCs and estimated that dashboard integration and data validation would take approximately two months after receiving complete final payment information from the EDCs. Id.

Eversource and UI also supported identifying the day and hour on which the annual ISO-NE system peak occurred on the Dispatch Event Metrics tab of the dashboard. Eversource Interrog. Resp. CAE-3, p. 1; UI Interrog. Resp. CAE-3, p. 1. UI stated that this information would enhance Program transparency and facilitate analysis of performance trends across Program years. UI Interrog. Resp. CAE-3, p. 1. Eversource noted that ISO-NE makes the final determination of the annual system peak day and hour in the following calendar year using settlement data rather than operational data. Eversource Interrog. Resp. CAE-3, p. 1.

CGB stated that the actual annual peak hour for prior seasons could be identified on the Dispatch Event Metrics tab through several approaches, including: (1) a separate indicator identifying whether a dispatch event coincided with the annual peak hour; (2) a visual flag or note within the existing event-level metrics; or (3) a summary field or filter allowing users to isolate events occurring during the applicable peak hour. CGB Interrog. Resp. CAE-3, p. 1. From a dashboard usability perspective, CGB recommended an event-level flag that could also be filtered or summarized, allowing users to readily distinguish dispatch events occurring during the annual system peak from other dispatch activity. Id.

2. Authority Analysis

Adding data enhancements to the ESS Program data dashboard—specifically, annual performance incentive payment information and identification of the annual ISO-NE system peak hour—will improve Program transparency. Publicly reporting actual performance incentive payments will provide greater visibility into Program costs and the performance payments associated with different OEMs and customer sectors. This information may also encourage OEMs to improve system performance relative to other manufacturers.

Similarly, identifying the annual ISO-NE system peak hour will provide greater transparency into whether ESS Program resources are being dispatched when system-wide peak reduction provides the greatest potential value to ratepayers. Reporting this information would facilitate evaluation of Program performance and enable a more effective assessment of the Program's contribution to peak reduction during this critical period.

Accordingly, the Authority directs CGB to add performance incentive payment information to the ESS Program data dashboard no later than April 1, 2027. The information shall be broken out by season, where applicable, customer sector, and OEM. The EDCs shall provide CGB with the information necessary to verify the accuracy and completeness of the reported performance incentive payment data. CGB may, at its discretion, normalize performance incentive payments by kW or another metric that CGB determines would provide the most useful comparison for customers and stakeholders.

The Authority further directs CGB, by April 1, 2027, to identify the annual ISO-NE system peak hour for all prior dispatch years on the Dispatch Event Metrics tab. CGB shall use a clear flag, filter, or comparable dashboard feature that allows users to readily identify and isolate dispatch events that occurred during the applicable annual system peak hour. CGB shall continue to add the annual ISO-NE system peak hour to the dashboard for each subsequent dispatch year once ISO-NE has made its final determination of the applicable peak hour.

F. PROGRAM REDLINE AND RECOMMENDED CHANGES

Order No. 3 of the Year 5 Decision directs the Program Administrators to file by August 1 annually "recommendations for any Program modifications." Year 5 Decision, p. 56. In compliance with Order No. 3, the Program Administrators filed proposed Program modifications and updated Program documents, including an updated Program Manual. See Program Administrator Order No. 3 Compliance, Aug. 3, 2026, Att. 4.

In this section, the Authority addresses revisions to the Program documents filed in compliance with Order No. 3 that are not addressed by other aspects of this Decision. Finally, the Authority approves all additional redline and programmatic changes proposed by the Program Administrators which are not discussed in this section or affected by other parts of the Decision.

1. Performance Payment Frequency

In the Year 5 Decision, the Authority directed the Program Administrators to provide participants with a choice between two performance incentive payment structures: (1) a new single annual payment option covering both the winter and summer dispatch seasons; or (2) the existing seasonal payment option, providing one payment following each dispatch season. Year 5 Decision, p. 23. The Authority approved the new single annual payment option because it would streamline Program administration by requiring only one annual performance calculation and was consistent with the Program Administrators' revised active dispatch incentive design proposal submitted last year. See Program Administrator Compliance, May 1, 2025, Docket No. 24-08-05, Att. 1, pp. 17, 22; Year 5 Decision, p. 23. The Authority nevertheless retained the existing seasonal payment option to avoid adversely affecting project economics due to the time value of money, as participants could otherwise experience a delay in receiving payment for performance during the earlier dispatch season. Year 5 Decision, p. 23.

The Program Administrators now seek to reverse that determination by revising the Program Manual to eliminate the single annual payment option and require all participants to receive performance incentives through two seasonal payments. Program Administrator Order No. 3 Compliance, Aug. 3, 2026, Att. 4, p. 3. According to the Program Administrators, the Program's DERMS providers indicated that administering a single annual performance incentive payment would present technical challenges. Id. The small number of participants that have already selected the single annual payment option would consequently be transitioned to the seasonal payment option. Id.

Furthermore, Eversource argued that paying incentives shortly after each dispatch season strengthens the connection between a participant's actions and associated reward, which could improve participant retention and year-over-year load curtailment. Eversource Interrog. Resp. CAE-1, p. 1. Eversource also asserted that seasonal payments reduce the risk of errors accumulating over longer settlement periods and allow the EDCs to identify underperforming accounts earlier, providing an opportunity for corrective action or targeted outreach before the subsequent dispatch season. Id., p. 2.

Eversource stated that its DERMS provider, EnergyHub, cannot currently accommodate an annual incentive payment. Eversource Interrog. Resp. CAE-27. Specifically, Eversource asserted that implementing such a payment structure would require custom development to enable a single annual payment covering two demand response seasons. Id.

UI similarly stated that maintaining multiple payment methodologies would introduce additional system and administrative complexity. UI Interrog. Resp. CAE-1, pp. 1–2. UI's DERMS provider advised that transitioning to annual performance incentive payments would require significant system modifications, including developing, testing, and implementing new reporting logic and additional data warehouse configurations. Id., p. 2. According to UI, these modifications would increase Program costs borne by ratepayers by approximately $40,000. Id.; UI Interrog. Resp. CAE-27.

Earthlight supported eliminating the annual payment option. Earthlight Comments, Aug. 28, 2026, p. 3. Earthlight argued that maintaining a biannual payment structure would bring Construct 5 customers into greater alignment with legacy customer payments, thereby streamlining operations for the Program Administrators. Id. Earthlight further argued that a biannual incentive payment structure provides system owners with tangible value sooner than an annual payment structure. Id.

The Authority does not reverse a prior determination lightly. In this case, the Authority would have preferred that the Program Administrators identify the implementation challenges associated with an annual payment structure before approval last year. This is particularly true because the annual payment option was consistent with the Program Administrators' original incentive design proposal intended to address issues associated with passive dispatch. See Program Administrator Compliance, May 1, 2025, Docket No. 24-08-05, Att. 1, pp. 17, 22.

Nevertheless, the Authority finds that the circumstances presented here warrant revisiting its prior determination. Maintaining both annual and seasonal payment structures would result in significant implementation costs and administrative complexity. In addition, no stakeholder opposed elimination of the annual payment option, and only six approved or submitted projects had selected the annual payment option as of August 3, 2026. See Program Administrator Order No. 3 Compliance, Aug. 3, 2026, Att. 4, p. 3. On balance, the administrative and implementation benefits of a single payment methodology outweigh the limited benefits of retaining an annual payment option for the small number of affected participants. Accordingly, the Authority approves the proposed change and directs the Program Administrators to remove the annual payment option from the Program Manual. Participants currently enrolled under the annual payment option shall be transitioned to the biannual payment structure.

2. Change Orders

The Program Administrators proposed allowing customers with projects approved under a now-closed legacy tranche, but not yet installed, to submit change orders to increase system size under unavoidable circumstances. Program Administrator Order No. 3 Compliance, Aug. 3, 2026, Att. 4, p. 6. The Program Administrators clarified, however, that change orders resulting in a significant increase in system size would require the entire system to transition to the current incentive rate. Id. The Program Administrators did not define the circumstances under which an approved but uninstalled project could increase its system size, nor did they establish a threshold for determining when an increase would be considered significant and therefore require the project to transition to the current incentive rate. See Id.

Accordingly, the Authority asked the Program Administrators to propose an appropriate percentage threshold for increases to a project's system size after approval but before incentive payment, identify the limited circumstances under which such increases should be permitted, and justify their recommendations. PURA Interrogatories, Aug. 12, 2026, p. 4.

Eversource was agnostic as to an appropriate threshold for increasing the size of an approved but unbuilt project. Eversource Interrog. Resp. CAE-18. Eversource noted that, from an interconnection perspective, projects are more commonly downsized than increased as a result of study findings. Id.

UI recommended against establishing a fixed percentage threshold for allowable system size increases. UI Interrog. Resp. CAE-18. UI argued that a fixed threshold could inadvertently restrict otherwise reasonable project modifications and create unnecessary barriers for customers whose projects are affected by circumstances beyond their control. Id.

Similarly, CGB opposed establishing a specific threshold, arguing that Program Administrator discretion would be more appropriate given the variety of circumstances that could necessitate a system size increase. CGB Interrog. Resp. CAE-18. Nevertheless, CGB stated that, if the Authority requires a fixed percentage threshold, the threshold should be no more than a 50% increase in kW. Id. CGB also anticipated that many change orders would instead result in system size reductions due to interconnection restrictions. Id.

The Authority will allow customers with projects approved under a now-closed legacy tranche, but not yet installed, to submit change orders to increase system size. However, such increases should be subject to a reasonable limit. The Authority is particularly concerned that, absent a defined threshold, significant increases in system size could be permitted while allowing projects to retain legacy incentive rates. Accordingly, the Authority will allow projects approved under a now-closed legacy tranche, but not yet installed, to increase their system size by no more than 5% for any reason.

The 5% threshold is consistent with size-related allowances under Connecticut's other renewable energy programs. The Non-Residential Renewable Energy Solutions (NRES) Program allows projects to increase their system size by up to 5% of the original approved bid size, regardless of the reason for the increase. Motion No. 11, Jan. 9, 2026, Docket No. 25-08-03, Annual Non-Residential Renewable Energy Solutions Program Review – Year 5, Att. 2a, p. 32. Similarly, the Residential Renewable Energy Solutions (RRES) Program allows a system's expected annual production to exceed a customer's highest annual consumption over any 12-month period within the preceding five years by no more than 5% for any reason. EDC Compliance, Ja. 22, 2026, Docket No. 25-08-02, Annual Residential Renewable Energy Solutions Program Review and Rate Setting – Year 5, Att. 1b, p. 25. Establishing a consistent 5% threshold across Connecticut's clean energy programs will reduce developer confusion, promote uniformity, and facilitate consistent administration.

For all projects, an increase of up to 5% shall not result in an increase to the project's previously approved upfront or enrollment incentive amount. This limitation will prevent customers from using a permitted size increase to obtain a greater upfront incentive and is appropriate because the purpose of allowing these increases is to accommodate project modifications, not to provide an opportunity to increase the upfront value of a legacy incentive award.

Allowing increases of up to 5% regardless of the underlying reason will reduce administrative burden and promote consistent application of the Program requirements. Requiring the Program Administrators to determine whether each proposed increase resulted from an "unavoidable" circumstance would require case-by-case judgments and could lead to inconsistent treatment of similarly situated projects. A defined 5% threshold instead provides a clear, administrable standard. Accordingly, change orders for projects approved under a now-closed legacy tranche, but not yet completed, will be allowed to increase system size by up to 5% for any reason. Any increase greater than 5% shall require the entire project to transition to the current applicable incentive rate.

3. Insurance Requirements

The Program Administrators revised the ESS Program's insurance requirements for contractors and TPOs to provide greater flexibility for different types of businesses. Program Administrator Order No. 3 Compliance, Aug. 3, 2026, Att. 4, p. 4. Specifically, the Program Administrators proposed removing the requirements that contractors and TPOs maintain automobile and workers' compensation insurance. Id.

OCC expressed concern that reducing the Program's insurance requirements could shift additional risk to customers or ratepayers. OCC Comments, Aug. 28, 2026, p. 2.

The Authority rejects this proposed change. The ESS Program has required contractors and TPOs to maintain automobile and workers' compensation insurance for several years. Motion No. 6, Jan. 23, 2023, Docket No. 22-08-05, ESS Clean Program Manual, p. 27. The Program Administrators have not demonstrated that circumstances have changed sufficiently to warrant removing these established requirements. Moreover, the Authority agrees with OCC that eliminating these insurance requirements could expose customers and ratepayers to additional risk.

For example, an uninsured contractor involved in an automobile accident resulting in significant liability could face financial distress or be unable to continue operating. Such an outcome could reduce the availability of contractors to serve the Program, complicate the servicing of existing ESS projects, or impede the completion of pending projects. Maintaining appropriate insurance requirements provides an important safeguard against these potential risks without materially undermining the Program's objectives.

Accordingly, the Authority rejects the proposed elimination of the automobile and workers' compensation insurance requirements. The Program Administrators shall retain the existing ESS Program requirements that contractors and TPOs maintain automobile and workers' compensation insurance.

4. Add-on Storage

The Program Administrators proposed a new process for allowing legacy passive dispatch customers to add new capacity to their existing energy storage systems. Program Administrator Order No. 3 Compliance, Aug. 3, 2026, Att. 4, p. 6. Specifically, the Program Administrators proposed allowing add-on capacity to participate in the ESS

Program on a case-by-case basis, provided that the add-on does not interfere with the existing capacity. Id. The Program Administrators proposed two potential approaches: (1) the customer would repay a prorated portion of the upfront passive dispatch incentive to CGB and convert the entire legacy and add-on project to Construct 5, or the applicable current incentive rate at the time of application; or (2) CGB would calculate a blended performance incentive rate based on the weighted average of the kWh capacity enrolled in passive dispatch and Construct 5, which have different performance incentive rates. Id.

Earthlight stated that it has received significant interest from passive dispatch customers seeking to add energy storage capacity to their existing installations. Earthlight Comments, Aug. 28, 2026, p. 3. Earthlight recommended two pathways for system owners seeking to add storage capacity. Id., p. 4. Under the first pathway, customers could add capacity under the same legacy program as the originally installed storage. Id. The add-on capacity would not receive an enrollment incentive, but the entire storage system would be eligible for dispatch under the legacy performance incentive compensation structure. Id. Under the second pathway, customers could add capacity and reenroll their existing legacy capacity in Construct 5. Earthlight Comments, Aug. 28, 2026, p. 4. The entire storage system would then be eligible to participate under the Construct 5 active dispatch compensation structure, with the customer repaying a prorated portion of the original upfront incentive to CGB in exchange for the performance and enrollment incentives available under Construct 5. Id.

OCC expressed concern that the Program Administrators' proposed blended performance incentive rate for add-on capacity, which would allow customers to retain their legacy enrollment, is inconsistent with the rationale for phasing out passive dispatch and transitioning customers to Construct 5. OCC Comments, Aug. 28, 2026, p. 2.

The Authority allows legacy projects to add storage capacity and transition the entire project to the Construct 5 performance incentive rates, or the performance incentive rates then in effect, subject to the following conditions. First, the customer shall repay a prorated portion of the original upfront incentive, calculated based on the remaining years of the Program. Second, any applicable clawback fees shall be repaid to the Program Administrators. Third, any Construct 5 enrollment incentive shall apply only to the add-on capacity and not to the existing legacy capacity. This approach allows legacy customers to expand their systems while providing a clear pathway for transitioning the entire project from passive dispatch to the current compensation structure.

The Authority will not, however, allow add-on capacity to participate under the blended performance incentive rate proposed by the Program Administrators. Allowing a legacy project to retain its passive dispatch enrollment while receiving a blended performance incentive would perpetuate the passive dispatch structure that the Authority has determined should be phased out in favor of compensation based more directly on actual performance. Moreover, the proposed blended approach would require the calculation and administration of individualized performance incentive rates based on the relative amounts of legacy and Construct 5 capacity in each project. Such individualized

rates could introduce unnecessary complexity into Program administration and EDC payment processes and potentially increase costs borne by ratepayers.

Allowing legacy customers to add capacity through conversion to Construct 5 provides a clearer and more administratively efficient framework while advancing the transition away from passive dispatch. As discussed in the Year 5 Decision, passive dispatch has presented pervasive compliance issues, technical challenges, and substantial clawback risks for participants. See Year 5 Decision, pp. 9, 30. Allowing customers to expand their systems while transitioning the entire project to Construct 5 is therefore consistent with the Authority's prior determination to move the ESS Program toward greater performance-based compensation.

Accordingly, the Program Administrators shall remove the blended performance incentive option for add-on capacity from the Program Manual. Legacy projects may add storage capacity only through the Construct 5 pathway described above, subject to repayment of the applicable prorated upfront incentive and any applicable clawback fees. Any Construct 5 enrollment incentive shall apply only to the add-on capacity.

5. Telemetry Data Audits

In Section 5.1 of their proposed Program Manual, the Program Administrators added the following sentence: "Any entity providing telemetry data in the Program may be subject to audits and/ or penalty fees, if data is not provided in the allowable timeframe and/or if there are data QC concerns." Program Administrator Order No. 3 Compliance, Aug. 3, 2026, Att. 6, p. 53. The Program Administrators stated that this change would help address data quality and timeliness concerns and thereby advance the first and third Program Objectives. Program Administrator Order No. 3 Compliance, Aug. 3, 2026, Att. 4, p. 7.

Base Power opposed adoption of the proposed sentence for several reasons. Base Power Comments, Aug. 28, 2026, pp. 3–4. Base Power expressed concern that the provision is overly vague because it does not define what duration of a data delay, or what type of "QC concern," would trigger an audit or penalty fee; specify the amount or schedule of any penalty fee; provide a cure period before a penalty is assessed; or distinguish a telemetry provider's failure from a data gap caused by the DERMS platform or another Program Administrator system outside the telemetry provider's control. Id. Base Power argued that, absent these clarifications, the provision would create an open-ended compliance risk for Program participants. Id., p. 4. Base Power also noted that the Program Manual already accounts for missing telemetry data through the performance incentive calculation, under which lapsed data results in dispatch performance being measured as zero and therefore reduces the performance incentive earned. Id.

The Authority supports efforts to improve the quality and timeliness of telemetry data. However, the proposed addition to Section 5.1 is insufficiently specific to establish a clear and predictable compliance standard. As Base Power noted, the provision does not identify the data delays or types of data quality concerns that would trigger an audit or penalty, establish the amount or methodology for calculating a penalty fee, provide an

opportunity to cure an identified deficiency, establish how a penalty would be enforced in the event of nonpayment, or explain how responsibility would be assigned when a data deficiency results from a system or entity outside the telemetry provider's control. These omissions create substantial uncertainty for Program participants and could result in inconsistent application and enforcement of the provision.

The Authority therefore rejects the proposed addition to Section 5.1. Without greater specificity regarding the circumstances that would trigger a penalty, the applicable penalty amounts and enforcement procedures, opportunities to cure, and the allocation of responsibility for data deficiencies, the provision does not provide participants with sufficient notice of their obligations or establish a sufficiently clear framework for enforcement. Accordingly, the Program Administrators shall remove the proposed addition.

Moreover, the Program Administrators already retain mechanisms to address telemetry data deficiencies. As recipients of telemetry data collected from OEMs through the DERMS, the Program Administrators retain the ability to audit such data. In addition, Section 4.3.6 allows the Program Administrators to place contractors, TPOs, aggregators, operators, payment beneficiaries, and OEMs on probation, suspend them, or terminate them if they fail to meet Program requirements, including requirements to provide telemetry data. Program Administrator Order No. 3 Compliance, Aug. 3, 2026, Att. 6, pp. 47–48. Given these existing enforcement mechanisms, the Authority is not persuaded that the Program Administrators have demonstrated a need for an additional, undefined penalty fee regime, particularly one that could create separate enforcement and collection issues in the event of nonpayment.

However, the existing enforcement authority under Section 4.3.6 will be exercised judiciously. Although failure to provide telemetry data consistent with Program requirements may constitute grounds for probation or suspension, such actions should not be taken lightly. The Authority expects the Program Administrators to provide participants with a reasonable opportunity to identify and correct deficiencies before taking such significant enforcement action and to assign responsibility to the entity actually responsible for the underlying issue.

The Authority agrees that telemetry data quality and timeliness are important considerations. Accurate and timely telemetry data is necessary for calculating performance incentive payments and conducting the Program's BCA. Accordingly, the Program Administrators may propose revisions to Section 5.1 in the next annual review to address the data quality and timeliness concerns underlying this year's proposed addition. The Program Administrators may also consider alternative solutions not previously explored, such as methods for obtaining API access directly from inverters. Any such proposal, however, should be substantially more developed and specific, including clear standards for triggering audits or penalties, the applicable penalty structure and enforcement procedures, opportunities to cure deficiencies, and a process for determining responsibility for data deficiencies.

6. Miscellaneous

The Authority addresses two additional changes to the Program Manual that require correction.

First, Table 1 of the ESS Program Manual, which identifies tranche capacity, contains an incorrect MW total for Construct 5. Program Administrator Order No. 3 Compliance, Aug. 3, 2026, Att. 5, p. 8. Specifically, Table 1 identifies 140 MW of commercial capacity under Construct 5 and 290 MW under the legacy program. Id. However, as of August 20, 2026, the Program website identifies only 111.6 MW of commercial capacity remaining across tranches one through three.[12] The Year 2 Decision established that any canceled or vacated capacity from earlier tranches would be moved to the final tranche of the Program. Year 2 Decision, p. 33. The Authority has not modified or reversed this determination.

Accordingly, the capacity totals in Table 1 should be revised to reflect the Authority's prior determination. The legacy Program column shall include only active projects approved under the legacy tranches that have not been canceled or moved to Construct 5, while the Construct 5 column should be increased to include all unused or vacated capacity from the earlier legacy tranches.

Second, the Program Administrators moved the passive dispatch provisions to a supplement near the end of the Program Manual because passive dispatch is no longer available to new customers. Program Administrator Order No. 3 Compliance, Aug. 3, 2026, Att. 2, p. 3. The Authority supports this organizational change because it makes the Program Manual clearer and easier for stakeholders to navigate. However, the Program Administrators inadvertently retained Table 8, which displays the upfront incentive adder amounts associated with passive dispatch. Program Administrator Order No. 3 Compliance, Aug. 3, 2026, Att. 5, p. 47.

Retaining Table 8 while removing the other passive dispatch provisions and references to the associated upfront incentives could create confusion and lead customers to incorrectly conclude that the incentive adders in Table 8 apply to Construct 5 participants. Accordingly, the Program Administrators shall remove Table 8 from the main body of the Program Manual.

7. Updated Documents

The Authority directs the Program Administrators to ensure that the final updated Program documents, filed in accordance with this Decision, accurately reflect the Authority's determinations, including those in Sections IV.B., Bidirectional EV Participation, IV.C., Enrollment Incentive Clawback, and IV.F., Program Redline and Recommended Changes.

By December 21, 2026, the Program Administrators shall file the updated ESS Program documents, including the Program Manual, for the Authority's review and

[12] See https://energystoragect.com/ess-performance-report/ (page 3, C&I Tranche Capacity).

approval. The filing must include both clean and redlined versions of all ESS Program documents, incorporating the modifications approved in this Decision.

V. CONCLUSION AND ORDERS

A. CONCLUSION

The Authority approves several changes to the ESS Program to better serve the Program Objectives and provides several additional clarifications for stakeholders.

B. EXISTING AND NEW ORDERS

For the following Orders, the Company shall file an electronic version through the Authority's website at www.ct.gov/pura. Submissions filed in compliance with the Authority's Orders must be identified by all three of the following: Docket Number, Title, and Order Number. Compliance with orders shall commence and continue as indicated in each specific Order or until the Company requests and the Authority approves that the Company's compliance is no longer required after a certain date. All Orders requiring Authority review and approval shall be submitted as a motion.

The below standing orders are a summation of prior orders related to the ESS Program that continue to apply. In some instances, the Authority has amended those standing orders with redline edits. Additionally, given the Program's maturity and the implementation of Construct 5 last year, Standing Order Nos. 2 and 7 are rescinded. The below new orders apply on a going forward basis.

1. Standing Orders to be filed in ESS Annual Review Dockets

1. Reference Decision, July 28, 2021, Docket No. 17-12-03RE03, Order No. 8, p. 52: No later than October 1, 2021, and by August 1 annually thereafter until the ESS Program stops accepting new enrollments, the EDCs shall submit as a compliance filing in the most recent annual review proceeding a map of circuits that meet the grid edge criteria in Section III.D. The EDCs shall include the map in all relevant Program documentation and on the EDCs' respective Program webpages.

~~2. Reference Decision, July 28, 2021, Docket No. 17-12-03RE03, Order No. 12, p. 52: No later than October 1, 2021, the EDCs shall provide a list of all electric storage systems that are eligible for the Program in Docket No. 21-08-05. Any updates shall be submitted in the appropriate Annual or Program Review docket by August 1, and annually thereafter until the ESS Program stops accepting new enrollments, as applicable.~~

3. Reference Decision, Dec. 21, 2022, Docket No. 22-08-05, Order No. 3, p. 38: No later than August 1, 2022, and annually thereafter until the ESS Program stops accepting new enrollments, the Program Administrators shall submit an annual report summarizing the Program results to date, including an updated BCA using AESC counterfactual one and an updated BCA calculator and including a CT-specific RIM score, and recommendations for any Program modifications to the ESS Program documents including the Program Manual, providing both a clean

and a redlined version of all documents and an accompanying narrative document explaining how the recommended changes would help achieve the Program Objectives, which may also be the annual report, in the relevant Annual Review proceeding (i.e., in Docket No. 23-08-05 on August 1, 2023, etc.). The Program Administrators shall include active dispatch only projects in the Program's total 580 MW deployment goal, and the Program Administrators shall exclude active dispatch only projects from the Program's Tranche and incentive step MW capacity limits. Further, the Program Administrators shall track total active dispatch only project MW deployment and include such information in the annual report filed with the Authority. Last, the Program Administrators shall include all DERMS fees paid to support the Program by each DERMS provider in an aggregate or total amount, and data on instances where a system could not perform due to OEM-triggered severe storm events called during uncanceled passive dispatch hours.

4. Reference Decision, July 28, 2021, Docket No. 17-12-03RE03, Order No. 25, p. 53: No later than June 15, 2024, and every three years thereafter until the ESS Program stops accepting new enrollments, the Program Administrators shall submit the EM&V consultant's full report on the established Program metrics into the relevant Program Review proceeding.

5. Reference Decision, Dec. 17, 2025, Docket No. 25-08-05, Order No. 5, pp. 56-57: Each Program Administrator shall submit their prudently incurred costs associated with the administration of the Program in a given calendar year into the subsequent year's annual review of the Revenue Adjustment Mechanism (RAM) (e.g., costs incurred in 2023 by UI shall be submitted into the 2024 RAM proceeding). The EDCs shall submit such costs into their individual RAM review docket, whereas the CGB may seek recovery of ESS Program costs that have not yet been incurred for the Program year of the RAM proceeding in which they are filing, in accordance with the guidance set forth in Section IV.N. of the Year 3 Decision. Further, CGB shall submit its detailed cost estimates for the subsequent Program year by January 15, and annually thereafter, into both dockets splitting its costs between Eversource and UI based on the proportion of megawatts deployed in each EDC's respective service territory. Additionally, CGB shall include the total amount of collected commercial application fees in its annual RAM filing, deducting the corresponding fee revenues from its Program administrative costs. Finally, repayment of the unearned incentive through CGB Proposal 2 must occur in full through the first available RAM cycle and shall not be spread over multiple years as CGB gradually collects performance payments. For example, if an existing passive dispatch project transitions to CGB Proposal 2 in 2026, CGB must return the full amount of the unearned upfront incentive to ratepayers in the 2027 RAM cycle as a part of its annual Order No. 5 filing. Specifically, CGB shall deduct the value of previously disbursed but unearned upfront incentive payments from its total program administrative costs—documenting this as a distinct cost line item—prior to seeking program administration cost recovery from the EDCs through the RAM process.

6. Reference Decision, July 28, 2021, Docket No. 17-12-03RE03, Order No. 24, p. 53: No later than January 1, 2023, the Program Administrators shall publish a website containing all relevant Program data, incorporating all direction provided in Section V.D.

7. ~~Reference Decision, Dec. 8, 2021, Docket No. 21-08-05, Order No. 9, p. 40: No later than August 1, 2022, and annually thereafter until the ESS Program stops accepting new enrollments, the Program Administrators shall submit its compliance with Order No. 22 of the Storage Decision, incorporating the direction provided in Sections IV.B.2. and V.A.4.iii. of this Decision.~~

8. Reference Decision, Dec. 21, 2022, Docket No. 22-08-05, Order No. 15, p. 41: No later than August 1, 2024, and annually thereafter until the ESS Program stops accepting new enrollments, CGB shall file all project cancellation data for the Authority's review in the relevant ESS annual review docket. The cancellation data must show which tranche the canceled projects were selected for, as well as the reasons behind the project cancellations, if known by the Program Administrators.

9. Reference Decision, Dec. 21, 2022, Docket No. 22-08-05, Order No. 16, p. 41: No later than 30 days from DAS adoption of an updated building code that incorporates best practices for electric storage, and annually thereafter, the Program Administrators shall file as compliance with the Authority the current best guidance on siting, local permitting, and safety for local officials and developers on FTM and behind-the-meter storage construction and development. Such guidance shall be developed in consultation with relevant state agencies, including DAS, DEEP, and the Siting Council. Such guidance shall also be provided on the ESS Program's website. A link to such guidance shall be provided to the Authority as a part of the compliance filing. Upon the fulfillment of this order, the Energy Storage Siting Resource shall be updated to incorporate any new siting guidance from DAS.

10. Reference Decision, Nov. 29, 2023, Docket No. 23-08-05, Order No. 18, p. 60: No later than January 5, 2024, and annually thereafter until the ESS Program stops accepting new enrollments, CGB shall provide updated fact sheets for both residential and C&I customers for the ESS Program that reflect the program modifications as directed in the most recent Final Decision issued through the ESS Program Annual Review proceeding, Docket No. XX-08-05.

11. Reference Decision, Nov. 29, 2023, Docket No. 23-08-05, Order No. 20, pp. 60-61: No later than April 1, 2024, the Program Administrators shall create an educational resource (Energy Storage Siting Resource) for Program participants compiling existing, publicly available resources regarding any applicable flood proofing, building code, safety, and siting requirements affecting residential and commercial ESS projects and providing relevant state and municipal contact information, which need not be exhaustive (e.g., "the relevant department in most municipalities are X, Y, Z"). For clarity, such resource shall simply aggregate

publicly available resources into one place for developer ease of access. The Program Administrators shall file the Energy Storage Siting Resource in the present docket, after which the resource shall be published on the ESS website. Further, the Energy Storage Siting Resource shall be updated when Order 10 of the Year 3 Decision is fulfilled, after a new building code for energy storage projects is adopted statewide, and annually thereafter until the ESS Program stops accepting new enrollments, to ensure the Resource remains up to date and relevant for Program developers. The Program Administrators shall file as compliance with the Authority in the applicable ESS proceeding (i.e., for 2024, Docket No. 24-08-05) any future updates to the Energy Storage Siting Resource.

12. Reference Decision, Nov. 29, 2023, Docket No. 23-08-05, Order No. 24, p. 62: No later than August 1, 2024, and annually thereafter until the ESS Program stops accepting new enrollments, CGB shall file as compliance in the applicable annual review proceeding (i.e., in 2024, Docket No. 24-08-05) the average participant cost test (PCT) broken out by customer type, project size category, and Program developer for both residential and commercial customer projects, utilizing all information available to CGB, including Performance Incentive Fee data, to ensure an accurate accounting of the PCT. The PCT shall also specifically be conducted from the perspective of the host customer; to the extent that this necessitates a change from the methodology that has historically been applied, CGB shall submit PCT values calculated using both the historical methodology and the customer-focused methodology.

13. Reference Decision, Nov. 29, 2023, Docket No. 23-08-05, Order No. 25, p. 62: No later than August 1, 2024, and annually thereafter until the ESS Program stops accepting new enrollments, the Program Administrators shall file as compliance in the applicable annual review proceeding (i.e., in 2024, Docket No. 24-08-05) a summary of the Performance Incentive Fees for all residential projects deployed through the end of the previous month (e.g., through July 2024 for the August 1, 2024 filing) by developer, following all direction contained in Section IV.G.

14. Reference Decision, Nov. 29, 2023, Docket No. 23-08-05, Order No. 26, p. 62: No later than August 1, 2024, and annually thereafter until the ESS Program stops accepting new enrollments, each EDC shall file as compliance an ESS Interconnection Report, as detailed in Section IV.D., in the applicable annual review proceeding (i.e., in 2024, Docket No. 24-08-05). The Report shall consist of a summary of the state of interconnection for all commercial ESS projects and shall include, at a minimum: (1) the interconnection status of each commercial ESS project; (2) the expected EDC interconnection approval due date for each commercial project per EDC interconnection guidelines, as applicable; (3) the date all required interconnection materials were submitted to the utility for each commercial ESS project; (4) the number of days from when all required interconnection materials were submitted to the utility for each commercial ESS project up to the completion of the interconnection process; (5) the attrition rate for all commercial ESS projects, based on the withdrawal of a project's

interconnection application; (6) a list of the most common reasons for ESS interconnection delays; and (7) EDC-proposed solutions for each of the most common reasons delaying ESS interconnections.

15. Reference Decision, Nov. 29, 2023, Docket No. 23-08-05, Order No. 30, p. 63: No less than once annually after the Energy Storage Siting Resource referenced in Order No. 20 of the Year 3 Decision is first completed, and until the ESS Program stops accepting new enrollments, CGB shall hold at least one seminar with Program stakeholders reviewing the siting and safety requirements for energy storage projects. The seminar shall help ensure that Program participants are informed of any potential energy storage code or safety changes. As compliance, CGB shall file the date of such seminar annually with the Authority in the applicable annual review proceeding (i.e., if 2024, Docket No. 24-08-05) no less than 10 days after such seminar is held.

16. Reference Decision, Dec. 4, 2024, Docket No. 24-08-05, Order No. 22, pp. 51-52: No later than November 1, 2025, and annually thereafter, the Program Administrators shall submit in the relevant annual review proceeding all recommended clawback fee waivers for Authority approval annually. This submission must include: (1) the total number and percentage of projects for which clawback fee waivers are recommended, categorized by residential and commercial sectors, as well as by battery manufacturer and contractor; (2) a clear and detailed rationale for each recommended fee waiver; and (3) an updated RIM score, illustrating the impact of waiving and not waiving clawback fees for the respective projects. All requests for clawback fee waivers shall be consolidated into a single motion for review and approval, rather than be submitted as separate filings for each waiver. Lastly, the Program Administrators shall first apply any clawback fees against a project's eligible performance incentive payments before pursuing direct collection from the customer.

17. Reference Decision, Dec. 17, 2025, Docket No. 25-08-05, Order No. 26, pp. 61-62: CGB shall update the ESS Program documents to reflect the adoption of CGB Proposals 1 and 2, as modified by this Decision, should CGB Proposals 1 and 2 be approved by CGB's Board of Directors. The updated Program materials shall include new, standalone terms and conditions for each proposal, clearly delineating the specific rights, obligations, and repayment provisions applicable to participating customers. System owners must expressly acknowledge and sign these terms and conditions before enrolling in CGB Proposal 1 or CGB Proposal 2, thereby ensuring that participants fully understand the financial and operational implications of enrollment. The updated Program documents shall also specify the maximum upfront incentive available to each customer class, as well as the estimated timeline for CGB's recovery of that incentive through performance payments. CGB shall also take steps to minimize customer confusion arising from the implementation of Proposals 1 and 2. When enrolling customers under either framework, CGB shall ensure that customers clearly understand: the financing process and expected recovery timelines; the nature of performance payments,

including that such payments will be made to CGB and netted against the upfront incentive until the balance is fully settled; and how incentive payments and enrollment terms may change depending on the proposal under which the customer enrolls. CGB shall file the updated Program documents as compliance in the present proceeding. Alternatively, if CGB decides not to pursue either CGB Proposals 1 or 2, CGB shall notify the Authority through a compliance filing in this proceeding.

18. Reference Decision, Dec. 17, 2025, Docket No. 25-08-05, Order No. 27, p. 62: CGB shall notify the Authority via a compliance filing in the present proceeding if a viable solution is identified to restore inoperable ESS systems (e.g., SunPower batteries) to operational status within the EDCs' DERMS platforms. CGB may issue a formal request for proposals to identify a suitable solution; however, if ratepayer funding is to be used, CGB must obtain Authority approval before entering into any contract.

2. New Orders

19. No later than December 21, 2026, the Program Administrators shall file for the Authority's review and approval updated ESS Program documents incorporating all the approved modifications authorized in this Decision. The Program Administrators shall ensure that the updated Program documents accurately reflect all the Authority's determinations, including those in Sections IV.B., Bidirectional EV Participation, IV.C., Enrollment Incentive Clawback, and IV.F., Program Redline and Recommended Changes. Such filing shall include both a clean and a redlined version of all ESS Program documents, including the Program Manual.

20. No later than January 4, 2027, the EDCs shall use the revised Interconnection Guidelines for all applicable bidirectional EV interconnection requests. See EDC Order No. 25 Compliance, July 1, 2026. The EDCs shall also update their respective interconnection webpages to include the revised Interconnection Guidelines and shall file compliance with the Authority confirming that such updates have been completed.

21. No later than March 1, 2027, CGB shall reestablish the FTM Storage Working Group and shall file compliance with the Authority upon its reestablishment. Subject to future prudence review, costs incurred by CGB in connection with this effort shall be eligible for consideration for cost recovery in future RAM proceedings and shall be submitted as a specific line item in CGB's RAM filing. CGB shall invite, at a minimum, the EDCs, DEEP, OCC, ACT, SEIA, CCSA, and all members of the original FTM Storage Working Group to participate in the process. See EDC Compliance, Docket No. 22-08-05, Dec. 29, 2023, WG Report, p. 19.

22. No later than April 1, 2027, CGB shall add performance incentive payment information to the ESS Program data dashboard no later than April 1, 2027. The

information shall be broken out by season, where applicable, customer sector, and OEM. The EDCs shall provide CGB with the information necessary to verify the accuracy and completeness of the reported performance incentive payment data. CGB may, at its discretion, normalize performance incentive payments by kW or another metric that CGB determines would provide the most useful comparison for customers and stakeholders. Further, by the same date, CGB shall identify the annual ISO-NE system peak hour for all prior dispatch years on the Dispatch Event Metrics tab. CGB shall use a clear flag, filter, or comparable dashboard feature that allows users to readily identify and isolate dispatch events that occurred during the applicable annual system peak hour. CGB shall continue to add the annual ISO-NE system peak hour to the dashboard for each subsequent dispatch year once ISO-NE has made its final determination of the applicable peak hour.

23. No later than August 1, 2027, the Program Administrators shall submit a compliance filing containing a recommendation as to whether residential bidirectional EVs should be eligible to participate in the ESS Program and, if so, under what conditions. The Program Administrators' compliance filing shall include, at a minimum, the following:
    a. **Pilot Results**. A detailed summary of the Bidirectional Energy IES pilot and Massachusetts Clean Energy Center (MassCEC) Vehicle to Everything (V2X) pilot results, including, where known, EV performance, dispatch participation and success rates, customer experience, and any identified barriers to residential V2G participation.
    b. **Market and Technology Readiness**. An updated assessment of the residential bidirectional EV market in Connecticut, including the number and types of residential EVs reasonably expected to be eligible for ESS participation and any material changes in market or technology readiness since the filing of the original Bidirectional EV Report.
    c. **Interconnection**. An assessment of the EDCs' experience applying the revised bidirectional EV interconnection requirements, including: any implementation issues identified through commercial participation and the IES pilot; material issues, ambiguities, or necessary modifications requiring correction to better refine bidirectional EV interconnection; and any additional modifications that may be necessary to facilitate residential participation. Although this will be a joint filing, the EDCs shall be solely responsible for this portion of the filing because the EDCs administer the interconnection process. If the assessment identifies a need for changes to the interconnection requirements, the EDCs shall submit both clean and redlined versions of the applicable Interconnection Guidelines as part of the filing.
    d. **BCA**. An updated assessment of the BCA impacts associated with residential bidirectional EV participation under a proposed incentive structure in which performance incentives for residential bidirectional EVs would match the performance incentives applicable to standalone residential storage and no enrollment incentives would be provided.

e. **Customer-Facing Issues**. An evaluation of customer-facing issues associated with residential participation and a proposed mitigation strategy. This evaluation shall consider, among other things, whether a minimum state-of-charge requirement should apply to residential bidirectional EVs participating in active dispatch, as well as other measures to mitigate potential vehicle damage and the risk that customers may be unable to use their EVs to meet transportation needs.
f. **Program Requirements**. Recommendations regarding any additional residential-specific eligibility requirements that should differ from or supplement the requirements applicable to commercial bidirectional EV charging systems. As part of this evaluation, the Program Administrators shall also consider whether the 20 kW per charging port minimum discharge capacity should be modified to allow for residential participation.
g. **Implementation Recommendations**. A proposed framework and implementation timeline for residential bidirectional EV participation, incorporating all the above.

24. No later than December 1, 2027, CGB shall submit, as compliance, a comprehensive FTM Storage Tariff Report. The report shall identify the FTM Storage Working Group's findings and recommendations regarding the feasibility and design of a bidirectional retail TOU tariff for standalone FTM storage and shall identify any issues that may require additional statutory authorization before implementation. At a minimum, the FTM Storage Tariff Report shall address:
    a. the appropriate structure and time periods for any bidirectional retail TOU tariff, including whether charging and discharging should be subject to different time-varying rates or credits;
    b. the specific distribution-level benefits that could appropriately be recognized through a retail tariff and the methodology for quantifying and attributing those benefits to participating resources;
    c. the appropriate compensation mechanism for identified distribution-level benefits, including whether compensation should vary based on time, system conditions, or other relevant characteristics;
    d. whether the tariff should provide location-specific compensation for FTM storage resources that can avoid or defer identified distribution system investments and, if so, how any such compensation should be calculated;
    e. the appropriate charge structure, including the treatment of transmission, distribution, and non-bypassable charges and whether alternative charge methodologies are necessary to avoid inappropriate or duplicative charges;
    f. the appropriate eligibility, sizing, metering, and performance requirements for participating FTM storage resources, including the treatment of co-located resources;
    g. how the tariff should interact with the WDAT and wholesale market participation, including appropriate mechanisms to avoid conflicting price signals and duplicate compensation;

h. whether alternative versions of the tariff should be developed to support participation in a subset of wholesale markets (e.g., forward capacity market only);
i. any federal legislation or regulation that explicitly permits or prohibits participation of an FTM storage resource in wholesale markets that takes service on a retail tariff;
j. the appropriate treatment of cost allocation and the potential impacts on participating and non-participating customer classes; and
k. the participant and ratepayer impacts of the proposed tariff, including the PCT and CT-RIM score, using ESS Program methodologies to the greatest extent possible.

APPENDIX A: List of Docket Participants

Participant	Representing
Eric Annes Department of Energy and Environmental Protection 10 Franklin Square New Britain, CT 06051	DEEP/BETP
Bernadette Antaki Michaud Law Group, LLC 101 Centerpoint Drive, Suite 230 Middletown, CT 06457	Kinsley Energy Systems, LLC; Nevar Company; Silver Brook Energy, LLC; Solar Alliance for Virtual Energy; Triad Advanced Energy Development, LLC; TRITEC Americas, LLC
Obinna Anugweje Staff Attorney Department of Energy & Environmental Protection 10 Franklin Square New Britain, CT 06051	DEEP/BETP
Greg Berger CPower	CPower
Prabisha Bhandari Office of Consumer Counsel 10 Franklin Square New Britain, CT 06051	OCC
Jeff Bishop Managing Director Key Capture Energy 150 State Street Salt Lake City, UT 84111	Key Capture Energy
Julian Boggs Manager, Regulatory & Policy Affairs Key Capture Energy 25 Monroe Street, 3rd. Floor Albany, NY 12210	Key Capture Energy
Ed Brolin RWE Clean Energy	RWE Clean Energy
Sean Burke BlueWave Project Development, LLC	BlueWave Development, LLC

116 Huntington Avenue, Suite 601 Boston, MA 02116	
Sergio Carrillo CT Green Bank 75 Charter Oak Avenue Hartford, CT 06106	CT Green Bank
Nancy Chafetz Sr. Director, Regulatory & Govt. Affairs Enerwise Global Technologies, Inc. d/b/a CPower 1001 Fleet Street, Suite 400 Baltimore, MD 21202	CPower
Alex Chaplin New Leaf Energy, Inc. 55 Technology Drive, Suite #102 Lowell, MA 01851	New Leaf Energy, Inc.
James Charles Sunnova Energy Corporation 20 Greenway Plaza, Suite 475 Houston, TX 77046	Sunnova Energy Corporation
Emma Cimino Acting Commissioner Department of Energy and Environmental Protection 79 Elm Street Hartford, CT 06106-5127	DEEP
Claire E. Coleman Consumer Counsel Office of Consumer Counsel 10 Franklin Square New Britain, CT 06051	OCC
Jameson Christopher Davis Nonprofit Accountability Group 12 Chatterton Woods Hamden, CT 06514	Nonprofit Accountability Group NAG
Amanda De Vito Trinsey, Esq. Couch White, LLP 540 Broadway P.O. Box 22222 Albany, NY 12201-2222	CIEC
Ruthie DeWit Director State Affairs, Northeast Region Solar Energy Industries Association	Solar Energy Industry Association

1425 K Street, Suite 1000 Washington, D.C. 20005	
Bryan Garcia President & CEO Connecticut Green Bank 75 Charter Oak Avenue Hartford, CT 06106	CT Green Bank
Dominic Gatti Policy Analyst, Energy Policy Tesla, Inc. 1333 H Street NW, Suite 1100 West Washington, DC 20006	Tesla, Inc.
Greg Geller Enel X Advisory Services USA, LLC f/k/a Enel X North America, Inc. One Marina Park Drive, #400 Boston, MA 02210	Enel X North America, Inc.
Kimberly Giese Energy Storage System Project Developer 174 Power Global Corporation 9 E. 37th Street, 12th Floor New York, NY 10016	174 Power Global Corporation
Dylan J. Gillis Michaud Law Group 101 Centerpoint Drive, Suite 230 Middletown, CT 06457	Solar Alliance for Virtual Energy
Nitzan Goldberger Energy Storage Association 1800 M Street, Suite 4005 Washington, DC 20036	Energy Storage Assoc.
Rachel Goldwasser General Counsel Key Capture Energy 25 Monroe Street, Suite 300 Albany, NY 12210	Key Capture Energy
S. Jay Goodman, Esq. Partner Couch White, LLP 540 Broadway P.O. Box 22222, Albany, NY 12201	CIEC
Sarah Griffiths Head of Regulatory Affairs (Northeast, Mid-West, Canada)	Enel X North America, Inc.

Enel X Advisory Services USA, LLC f/k/a Enel X North America, Inc. One Marina Drive, #400, Boston, MA 02210	
Justin Gundlach Institute of Policy Integrity at NYU School of Law 139 MacDougal Street, 3rd. Floor New York, NY 10012	IPI at NYU School of Law
Alice Horgan Sunnova Energy Corporation 20 Greenway Plaza, Suite 475 Houston, TX 77046	Sunnova Energy Corporation
Cynthia Jennings Law Office of Cynthia R. Jennings 340 Broad Street, Suite 300 Windsor, CT 06095	Nonprofit Accountability Group NAG
Angela Kent Manager, Regulatory Affairs EnergyHub, Inc. 41 Flatbush Avenue, Suite 40A Brooklyn, NY 11217	EnergyHub, Inc.
Shannon C. King	OCC Consultant
Ted Ko Director of Policy Stem, Inc. 100 Rollins Road, Millbrae, CA 94030	Stem, Inc.
Joel M. Kopylec Director, Regulatory Services & Policy UIL Holdings Corporation 180 Marsh Hill Road Orange, CT 06477	UI
Anna Bella Korbatov VP Regulatory Affairs Fermata Energy 2488 Historic Decatur Rd. Suite 200 San Diego, CA 92106	Fermata Energy
Alex Kovtunenko CT Green Bank 845 Brook Street Rocky Hill, CT 06067	CT Green Bank
Shannon Laun, Esq. Conservation Law Foundation, Inc.	Conservation Law Foundation

62 Summer Street Boston, MA 02110	
Julie Lelek, Esq. Staff Attorney Office of Consumer Counsel 10 Franklin Square New Britain, CT 06051	OCC
Steve Letendre Vehicle Grid Integration Council 1401 21sr Street, #5409 Sacramento, CA 95811	Vehicle Grid Integration Council
Emma Marshall-Torres Scale Microgrids	Scale Microgrids
Alison McHorney, Esq. Staff Attorney Office of Consumer Counsel 10 Franklin Square New Britain, CT 06051	OCC
Paul R. Michaud Michaud Law Group, LLC 101 Centerpoint Drive, Suite 230 Middletown, CT 06457	Kinsley Energy Systems, LLC; Nevar Company; Silver Brook Energy, LLC; Solar Alliance for Virtual Energy; Triad Advanced Energy Development, LLC; TRITEC Americas, LLC
Andrew Minikowski Legal Director Office of Consumer Counsel 10 Franklin Square New Britain, CT 06051	OCC
Kevin Morgan World Energy Efficiency Services	World Energy Efficiency Services
Meghan Nutting Sunnova Energy Corporation 20 Greenway Plaza, Suite 540 Houston, TX 77046	Sunnova Energy Corporation
Peter A. Olmsted Director of Regulatory Affairs Free Wire Technologies 53 Greenfield Avenue Saratoga Springs, NY 12866	Free Wire Technologies
Vincent P. Pace Assistant General Counsel	Eversource

Eversource Energy Service Company 107 Selden Street, Berlin, CT 06037	
Bronte Payne Senior Manager, Policy and Strategy SunPower Corporation 880 Harbour Way South, Suite 600 Richmond, CA 94804	SunPower Corp.
Paschaline Poku Staff Attorney Office of Consumer Counsel 10 Franklin Square New Britain, CT 06050	OCC
Christie Prescott UIL Holdings Corporation 180 Marsh Hill Road Orange, CT 06477	UI
Sean Riel Director of Sales Operations Earthlight Technologies, LLC 128 West Road Ellington, CT 06029	Earthlight Technologies, LLC
Jessica Robertson New Leaf Energy, Inc. 55 Technology Drive, Suite #102 Lowell, MA 01851	New Leaf Energy, Inc.
J. Brendan Sharkey, Esq. AmeriZone Consulting, LLC 79 Laurel Ridge Trail, Killingworth, CT 06419	AmeriZone
Tim Snyder Alliance for Climate Transition 444 Somerville Avenue Somerville, MA 02143	NECEC; Alliance for Climate Transition
Megan J. Sullo Office of Consumer Counsel 10 Franklin Square New Britain, CT 06051	OCC
Mike Trahan Connecticut Solar and Storage Association P.O. Box 515 Higganum, CT 06441	Solar CT, Inc.
Kyle Wallace Senior Manager, Public Policy	Sunrun, Inc.

Sunrun, Inc. 225 Bush Street, Suite 1400 San Francisco, CA 94104	
Alex Wang Office of Consumer Counsel 10 Franklin Square New Britain, CT 06051	OCC
Tonja Wicks Elevate Renewables F7, LLC 200 Clarendon Street, Floor 55 Boston, MA 02116	Elevate Renewables F7, LLC
R.L. Willoughby	OCC Consultant
Zach Woogen Vehicle Grid Integration Council 1401 21sr Street #5409 Sacramento, CA 95811	Vehicle Grid Integration Council
Katherine Zoellmer Market Design Analyst Key Capture Energy 25 Monroe Street, Suite 300, Albany, NY 12210	Key Capture Energy