STATE OF CONNECTICUT

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

DOCKET NO. 17-12-03RE03 **PURA INVESTIGATION INTO DISTRIBUTION SYSTEM PLANNING OF THE ELECTRIC DISTRIBUTION COMPANIES – ELECTRIC STORAGE**

July 28, 2021

By the following Commissioners:

Marissa P. Gillett
John W. Betkoski, III
Michael A. Caron

DECISION

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DECISION

I. INTRODUCTION

A. SUMMARY

Pursuant to Public Act (PA) 21-53 and §§ 16-11 and 16-244i of the General Statutes of Connecticut (Conn. Gen. Stat.), and in accordance with the Interim Decision dated October 2, 2019 in Docket No. 17-12-03, PURA Investigation into Distribution System Planning of the Electric Distribution Companies (Equitable Modern Grid Decision), the Authority establishes the statewide electric storage program (Electric Storage Program or Program) defined herein, which shall be available to all customers and customer classes within the service territories of The Connecticut Light and Power Company d/b/a Eversource Energy (Eversource) and The United Illuminating Company (UI; collectively, electric distribution companies). The electric distribution companies (EDCs) and the Connecticut Green Bank (CGB; collectively, Program Administrators) shall develop, for the Authority's review and approval, the appropriate program documents and additional program rules as directed in this Decision, as well as all associated documents necessary to effectively implement the final version of the Program (Program Design Documents). The Program Administrators shall not deviate from or modify in any way the final Program Design Documents without approval by the Authority. A Program Summary is appended as Appendix A.

B. BACKGROUND OF THE PROCEEDING

In the Equitable Modern Grid Decision, the Authority specified a series of reopened proceedings to further investigate a number of near-term topics integral to realizing the objectives outlined in its Framework for an Equitable Modern Grid. Equitable Modern Grid Decision, pp. 24-25. In accordance with the Equitable Modern Grid Decision, the Authority initiated the above-captioned proceeding on October 4, 2019, to investigate the topic of electric storage in Connecticut and to explore programs and technology applications to most effectively leverage the value of electric storage for the net benefit of the electric distribution system. The Authority's goal in this proceeding was to develop and implement a program for electric energy storage systems connected to the electric distribution system that provide multiple types of benefits to the grid, including but not limited to: customer, local, or community resilience; ancillary services; peak shaving; and support for the deployment of other distributed energy resources. Notice of Proceeding, dated October 7, 2019, p. 1. The Authority also set out to foster the sustained, orderly development of a state-based electric storage industry, and to determine the appropriate cost-benefit methodology to ensure the Program delivers net positive benefits to ratepayers. Request for Program Design (RFPD), dated May 6, 2020, p. 1.

C. CONDUCT OF THE PROCEEDING

On October 7, 2019, the Authority issued a Notice of Proceeding conducting this uncontested proceeding pursuant to Conn. Gen. Stat. §§ 16-11, 16-19eee, 16-19fff, 16-19ggg, and 16-244i.

On October 24, 2019, the Authority issued a Notice of Request for Presentations and Information and Notice of Solutions Days. The Authority held "Solutions Day" Technical Meetings on November 14 and 15, 2019 at its offices, Ten Franklin Square, New Britain, Connecticut.[1]

On, March 31, 2020, the Authority issued a draft Request for Program Design (RFPD) proposals in a Notice of Request for Written Comments. On May 6, 2020, the Authority issued a final RFPD, with a deadline for docket Participants and interested stakeholders to provide responsive proposals and to submit written comments by July 31, 2020. In response, the Authority received eight (8) program design proposals.

On January 5, 2021, the Authority issued its Notice of Issuance of Straw Electric Storage Program Design (Straw Proposal) and Request for Written Comments. In response, the Authority received fifteen (15) sets of written comments.

On January 26, 2021, the Authority issued a Notice of Technical Meeting, and on February 1, 2021, the Authority held a Technical Meeting via Zoom teleconference. Subsequently, the Authority issued interrogatories to various docket Participants on February 4, 2021. On February 18, 2021, the Authority issued a Notice of Hearing, and on February 26, 2021, the Authority held a hearing meeting via Zoom teleconference. Following the hearing, the Authority received five Late File Exhibits on March 9, 2021. The Authority held a Late File Exhibit hearing on March 17, 2021. The Authority received briefs from eight (8) Participants between March 31 and April 7, 2021.

The Authority issued a Proposed Final Decision on July 1, 2021 and provided an opportunity for Participants to file Written Exceptions and to present Oral Argument. The Authority held Oral Arguments on July 19, 2021.

D. PARTICIPANTS

A list of all Participants to this proceeding is appended as Appendix B.

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[1] See, PURA November 14th Technical Meeting on Electric Storage, https://www.ct-n.com/ctnplayer.asp?odID=16882; PURA November 15th Technical Meeting on Electric Storage, https://www.ct-n.com/ctnplayer.asp?odID=16886.

II. STATUTORY AUTHORITY

The Authority is mandated under the broad language of Conn. Gen. Stat. § 16-11 to order reasonable improvements, repairs, or alterations to a public service company's plant or equipment, or such changes in the manner of operation, as may be reasonably necessary and in the public interest. Additionally, Conn. Gen. Stat. § 16-244i requires the Authority to regulate the EDCs in accordance with the provisions of Conn. Gen. Stat. §§ 16-19 and 16-19e, and each EDC is obliged to connect all customers to its distribution system, subject to the rates, terms, and conditions as may be approved by the Authority in accordance with section 16-19 and the principles in subsection (a) of section 16-19e.

The Authority, in exercising its full powers under Title 16, examines and regulates the expansion of the plant and equipment of the EDCs, the operations and internal workings of the EDCs, and the establishment of the level and structure of rates consistent with the following principles:

> (1) That there is a clear public need for the service being proposed or provided. . . (3) that the authority and all public service companies shall perform all of their respective public responsibilities with economy, efficiency, and care for public safety and energy security, and so as to promote economic development within the state with consideration for energy and water conservation, energy efficiency and the development and utilization of renewable sources of energy and for the prudent management of the natural environment; (4) that the level and structure of rates be sufficient, but no more than sufficient, to allow public service companies to cover their operating costs . . . and yet provide appropriate protection to the relevant public interests, both existing and foreseeable. . . .

Conn. Gen. Stat. §16-19e(a)

The General Assembly articulated additional principles, which broadly apply to the Authority's oversight of the EDCs and the EDCs' obligations to the public:

> (1) The provision of affordable, safe, and reliable electricity is key to the continuing growth of this state and to the health, safety and general welfare of its residents; . . . (8) The assurance of safe, reliable and available electric service to all customers in a uniform and equitable manner is an essential governmental objective and a restructured electric market must provide adequate safeguards to ensure universal service and customer service protections; . . . (12) it is in the best interest of the state for all customers to use electricity as efficiently as possible.

Conn. Gen. Stat. § 16-244

Here, the Authority exercises its broad statutory powers and obligations under Conn Gen. Stat. §§ 16-11 and 16-244i to establish the Electric Storage Program. The Authority finds that the Program is necessary and in the public interest, pursuant to its statutory authority and the State's overarching objectives.

Finally, as stated in more detail herein, the General Assembly specifically mandated through Public Act 21-53, An Act Concerning Energy Storage, that the Authority commence this proceeding to develop and implement one or more programs in furtherance of Connecticut's energy storage goals.

A. PUBLIC ACT 21-53

Governor Lamont signed PA 21-53 into law on June 16, 2021.[2] Section 1 of PA 21-53 establishes an energy storage goal of one thousand (1,000) megawatts (MW) by December 31, 2030, along with interim goals of three hundred (300) MW by December 31, 2024, and six hundred fifty (650) MW by December 31, 2027. Section 2 of PA 21-53 directs the Authority to "develop and implement one or more programs, and associated funding mechanisms, for electric storage resources connected to the electric distribution system." The program(s) are required to include residential, commercial, and industrial customers, as well as systems connected in front of the meter and not at a customer's own premise. The Authority is required to report to the General Assembly the status of the proceeding by January 1, 2022, and the "quantifiable progress" toward the stated deployment goals by January 1, 2023.

Section 2 of PA 21-53 also directs the Authority to consider programs and rate designs that leverage electric storage systems to achieve four (4) objectives: (1) providing positive net present value to all ratepayers, or a subset of ratepayers paying for the benefits that accrue to that subset of ratepayers; (2) providing multiple types of benefits to the electric grid, including, but not limited to, customer, local, or community resilience, ancillary services, leveling out peaks in electricity use or that support the deployment of other distributed energy resources; (3) fostering the sustained, orderly development of a state-based electric energy storage industry; and, (4) maximizing the value from the participation of energy storage systems in capacity markets. Finally, Section 2 permits the Authority to select the CGB, DEEP, EDCs, or another third party to implement such programs.

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2 See, Public Act 21-53, https://www.cga.ct.gov/2021/ACT/PA/PDF/2021PA-00053-R00SB-00952-PA.PDF.

III. ELECTRIC STORAGE PROGRAM DESIGN

The Authority establishes the Electric Storage Program, as outlined herein, based on the record in this proceeding, including responses to the Authority's RFPD, Request for Written Comments on the Straw Proposal, Interrogatories, and other publicly available information. The key program elements include a declining-block upfront incentive and a performance-based incentive structure, which together comprise a nine-year Program available to all customers of the state's EDCs with an end goal of deploying 580 MW of electric storage by 2030. The Program shall be administered jointly by the CGB and the EDCs; the CGB shall administer the upfront incentive portion and shall be responsible for the communication and promotion of the Program, while the EDCs shall administer the performance incentive portion of the Program. The CGB and the EDCs shall jointly be responsible for Evaluation, Measurement, and Verification (EM&V). All other program administration duties shall be assigned as detailed herein. Where program administration duties have not yet been assigned or require clarification, the CGB and the EDCs shall submit a written proposal regarding the assignment of such duties for the Authority's review and approval.

A. PROGRAM OBJECTIVES

In the Equitable Modern Grid Decision, the Authority noted that electric storage technologies have numerous use cases through which electric storage provides various value streams and electric system benefits. Accordingly, the Authority opened the instant proceeding to explore programs that most effectively leverage the value of electric storage for the net benefit of the electric distribution system. Equitable Modern Grid Decision, p. 13. Specifically, in its Notice of Proceeding, the Authority stated such electric distribution system benefits may include, but are not limited to: "customer, local, or community resilience; support for DER deployment; ancillary services; and peak shaving." Notice of Proceeding, dated October 7, 2019, p. 1.

On May 6, 2020, the Authority issued a Request for Program Design proposals, which formally identified the following objectives for an electric storage program in Connecticut:

1) <u>Provide positive net present value to all ratepayers</u>, or a subset of ratepayers paying for the benefits that accrue to that subset of ratepayers;
2) <u>Provide multiple types of benefits to the electric grid</u>, 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; and
3) <u>Foster the sustained, orderly development of a state-based electric energy storage industry</u>.

On July 31, 2020, the Authority received eight submissions in response to its RFPD. Shortly thereafter, Connecticut was hit by Tropical Storm Isaias, which left more than 800,000 electric utility customers without power, many for over a week. Customers who lost power included those in economically distressed and environmental justice communities, in nursing homes and other medical care facilities, with medical conditions that require electrical devices for at-home care, and countless facilities deemed "critical" by local, state, and utility officials.[3] The impact of Tropical Storm Isaias underscored the importance of a resilient electric grid and the importance of the resilience benefits that electric storage can provide. Accordingly, the Authority added the following objective to the Program:

4) Prioritize delivering increased resilience to: (1) low-to-moderate income (LMI) customers, customers in environmental justice or economically distressed communities, customers coded medical hardship, and public housing authorities as defined in Conn. Gen. Stat. § 8-39(b); (2) customers on the grid-edge who consistently experience more and/or longer than average outages during major storms;[4] and (3) critical facilities as defined in Conn. Gen. Stat § 16-243y(a)(2).

Further, in response to the Authority's RFPD, New England Clean Energy Council (NECEC) and the U.S. Energy Storage Association (ESA) jointly supported exploring program designs that overcome the barriers to entry for electric storage deployment in Connecticut. NECEC/ESA RFPD Response, p. 1. NECEC and ESA also contended that peak hour energy use drives high emissions, and shifting load through electric storage programs could lower net emissions. Id., pp. 2 and 14. Similarly, the DER Task Force asserted that environmental performance should be a factor in electric storage compensation. DER Task Force RFPD Response, p. 2. Based on these responses, the Authority adopted the following, additional objectives:

5) Lower the barriers to entry, financial or otherwise, for electric storage deployment in Connecticut; and
6) Maximize the long-term environmental benefits of electric storage by reducing emissions associated with fossil-based peaking generation.

Finally, PA 21-53 directs the Authority to consider programs that achieve objectives 1 through 3 listed above, and adds a final objective to: "maximiz[e] the value from the participation of energy storage systems in capacity markets." The Authority interprets this objective to mean that the Authority is to maximize the value of capacity market participation to ratepayers. Accordingly, the Authority adopts the following program objective:

7) Maximize the benefits to ratepayers derived from the wholesale capacity market.

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[3] On April 28, 2021, the Authority issued a Final Decision in Docket No. 20-08-03, Investigation into Electric Distribution Companies' Preparation for and Response to Tropical Storm Isaias, evaluating the EDCs' performance in preparing for and responding to Tropical Storm Isaias. See, http://www.dpuc.state.ct.us/dockcurr.nsf/8e6fc37a54110e3e852576190052b64d/9c3dfa93dc6c03d4852586c50052218a/$FILE/200803-042821.pdf

[4] Major storms are defined in the Decision in Docket No. 86-12-03, dated March 22, 1995, p. 2. The "major storm exclusion criterion [that] is based on a statistical analysis of the most recent four calendar years of reliability data. A cumulative frequency distribution of the number of locations requiring service restoration work per day would be calculated for this four-year period. Whenever the frequency of restoration work locations exceeds the 98.5 percentile, by company and/or region, the major storm criterion would be met."

DEEP supported the Authority's stated objectives 1 through 6, particularly that the program provide net positive value through multiple types of grid benefits, prioritizing increased resilience to LMI, grid edge, and critical facility customers, and maximizing the long-term environmental benefits of the Program. DEEP Written Comments, dated January 26, 2021, pp. 2-5. NECEC and ESA jointly agreed with the Authority's objectives, noting the range of benefits that could be supported. NECEC/ESA Written Comments, dated January 26, 2021, p. 2. AmeriZone similarly agreed and commented that the objectives complement each other, particularly in supporting the sustained, orderly development of the state-based storage industry. Accordingly, the Authority adopts the objectives outlined above (Program Objectives) to guide its development of the Program. The Program Objectives shall guide the Program Administrators in their implementation of the Program established herein.

B. PROGRAM LENGTH AND STATEWIDE ELECTRIC STORAGE DEPLOYMENT TARGETS

As discussed above, PA 21-53 establishes an aspirational statewide energy storage target of 1,000 MW by the end of 2030.[5] Based on the presumption that a statewide target of 1,000 MW would be established,[6] NECEC and ESA proposed a 580 MW total Program deployment target, which accounts for the two percent highest demand summer hours in 2018. NECEC RFPD Response, pp. 8-9. NECEC noted that the Massachusetts Energy Storage Initiative State of Charge Report[7] determined that the one percent highest cost hours from 2013-2015 were responsible for eight percent of Massachusetts ratepayers' annual electricity costs, on average. Id. Since the 2018 peak hourly demand in Connecticut was 6,591 MW, and removing the top two percent of hours results in a peak hourly demand of 6,004 MW, NECEC stated that deploying 580 MW of electric storage would likely provide significant benefits. Id. NECEC also noted that targeting 58% of the 1,000 MW statewide goal leaves space for other policy options the state may pursue.[8] Id.

UI stated a 580 MW total program deployment target and a 100 MW target for the first three years is appropriate. UI Written Comments, dated January 26, 2021, p. 7. DEEP initially supported a nine-year program and an initial 100 MW target by 2025, but proposed waiting to determine the ultimate Program target until after a full Program evaluation is completed in 2024. DEEP Written Comments, dated January 26, 2021, pp. 5-6. DEEP later suggested that initially targeting 50 – 60 MW over five years may be more appropriate, and proposed the Authority wait until more information is available about potential changes in regional energy markets. DEEP Brief, pp. 8-9.

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[5] Section 1 of PA 21-53 sets a goal of three hundred (300) MW of in-state energy storage by December 31, 2024, and six hundred fifty (650) MW by December 31, 2027.

[6] See, Raised House Bill 5351 (2020) – An Act Concerning Certain Programs and to Incentivize and Implement Electric Energy Storage Resources, Connecticut General Assembly, Energy and Technology Committee, February Session, 2020, https://www.cga.ct.gov/asp/cgabillstatus/cgabillstatus.asp?selBillType=Bill&bill_num=HB5351&which_year=2020, last visited March 19, 2020.

[7] See, State of Charge Massachusetts Energy Storage Initiative Study, https://www.mass.gov/media/6441/download.

[8] For example, Section 3 of PA 21-53 gives DEEP the authority to procure energy storage projects apart from the Program authorized herein.

The Authority appreciates the nascent nature of the electric storage industry in Connecticut and agrees that market conditions affecting electric storage are likely to change in the coming years. However, given the 1,000 MW target adopted in PA 21-53, coupled with the Authority's Program Objectives to lower the barriers to entry and to foster the sustained, orderly development of a state-based electric storage industry, the Authority finds that a 2030 deployment target equal to *at least* 580 MW is necessary. Further, the Authority also finds a 2025 deployment target equal to 100 MW appropriate to further support the industry's sustained, orderly development. Accordingly, the Authority adopts the Electric Storage Deployment Targets shown in Table 1 to support a nine-year program commencing January 1, 2022 and running through at least December 31, 2030. As detailed in Section V.E., the Program will include three-year program review cycles to evaluate whether the Program is delivering on the expected value to Connecticut's ratepayers and is meeting the Program Objectives stated above. During each three-year program review, the Authority will reassess the program deployment targets and the breakdown of the deployment targets by customer class, considering the current status of energy storage in Connecticut. The Program will also include annual processes to review key program metrics and to adjust Program rules as necessary.[9]

Table 1: Electric Storage Deployment Targets

CUSTOMER CLASS	2022-2024	2025-2027	2028-2030	TOTAL
Residential	50 MW	100 MW	140 MW	290 MW
Commercial and Industrial	50 MW	100 MW	140 MW	290 MW
Total	**100 MW**	**200 MW**	**280 MW**	**580 MW**

C. COMPENSATION STRUCTURE

The Authority establishes two compensation mechanisms for electric storage systems participating in the Program:

(1) an upfront incentive administered by the CGB; and
(2) performance-based incentives administered by the EDC whose territory in which the electric storage system is interconnected.

The upfront incentive administered by the CGB shall be structured as a declining block incentive for residential customers and a single block for commercial and industrial customers, with the incentive levels set for each three-year program cycle at the beginning of that three-year cycle. For consistency across clean energy programs, specifically the Residential and Non-Residential Tariffs Programs authorized in Docket No. 20-07-01, PURA Implementation of Section 3 of Public Act 19-35, Renewable Energy Tariffs and Procurement Plans, each incentive may be provided as a direct payment, with customers afforded the option to assign a portion of the compensation to a third party.[10]

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[9] Should the Program Administrators find it necessary to bifurcate the deployment targets by EDC service territory, the Authority encourages the Program Administrators to use the 80/20 (Eversource/UI) split typically employed for the state's renewable energy programs.

[10] The Program Administrators shall include any direct payment parameters (e.g., payment frequency, etc.) and process (e.g., specify during the application process) in the Program Design Documents submitted

The Authority will review both incentive levels annually, with the advice and consultation of the Program Administrators, as detailed in Section V.E.

1. Residential Upfront Incentive

In its RFPD response, the CGB proposed a declining block structure for an upfront incentive. CGB RFPD Response, pp. 9-10. The CGB's proposal included five incentive steps for a total capacity of 50 MW, along with effective upfront incentives for individual projects ranging from $560 - $260 for LMI participants[11] and $280 - $130 for non-LMI participants. Id. Table 2 shows the CGB's proposed declining block, upfront incentives for LMI and non-LMI customers.

Table 2: CGB Proposed Residential Customer Upfront Incentive (2022-2024)

INCENTIVE STEP	ESTIMATED # OF PARTICIPANTS	CAPACITY BLOCK (MW)	NON-LMI EFFECTIVE UPFRONT INCENTIVE ($/KWH)[12]	LMI EFFECTIVE UPFRONT INCENTIVE ($/KWH)	AVERAGE UPFRONT INCENTIVE PER SYSTEM
1	400	2.0	$280	$560	$3,950
2	700	3.5	$240	$480	$3,400
3	1,300	6.5	$200	$400	$2,900
4	2,600	13.0	$170	$340	$2,350
5	5,000	25.0	$130	$260	$1,850
Total	10,000	50.0			$2,300

The CGB stated that the effective upfront incentive assumes a 5 kW, 13.5 kWh battery, and a formula would be used to determine the actual incentive for each participating device. Tr. 2/1/21, pp. 35-37. The CGB's proposed incentive level is based on the minimum of the following five values:

1. BESS usable energy capacity (kWh) * $375/kWh
2. BESS maximum power output rating (kW) * 2 hrs * $375/kWh
3. Solar PV system nameplate rating (kW) * 2 hrs * $375/kWh
4. 50% of BESS total installed cost
5. Maximum per project inventive of $7,000

CGB Response to CAE-7, pp. 1-2.

The CGB also proposed a $7,500 upfront incentive cap per participant. CGB RFPD Response, p. 10.

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for the Authority's review and approval. Such direct payment parameters and process shall follow the Decisions issued February 10 and June 30, 2021 in Docket No. 20-07-01.

[11] CGB defined LMI households as households with less than 100 percent area median income. See, CGB RFPD Response, p. 9.

[12] The effective incentive level for both non-LMI and LMI residential participants factors in the usable energy capacity (kWh) and the maximum power output rating (kW) of the energy storage system. The incentive is adjusted based on kWh and kW capacity.

The Authority finds that the upfront declining block incentive structure proposed by the CGB aligns with the Program Objectives to lower barriers to entry for electric storage deployment in Connecticut. Accordingly, the Authority authorizes the declining capacity blocks for residential customers as shown in Table 2 (i.e., capacity blocks of 2.0, 3.5, 6.5, 13.0, and 25.0 MW).[13] Additionally, the Authority authorizes the upfront incentive to be capped at $7,500 as recommended by the CGB. During Oral Arguments, the CGB and NECEC agreed that removing the CGB's formula (3) above would appropriately incentivize standalone storage systems. Tr. 7/19/21, pp. 12-13, 16-18. The CGB and NECEC also agreed that removing the CGB's formula (2) would incentivize projects that provide more than two hours of grid benefits. As the Program explicitly seeks to allow both co-located *and* standalone storage projects, the Authority finds the removal of formula (3) appropriate. Further, the Authority believes that the removal of formula (2) is also likely in the best interest of the Program; however, insufficient record evidence exists to reach such a conclusion. Accordingly, the Authority directs the CGB to calculate the residential upfront incentive based on the minimum of formulas (1), (2), (4), and (5) above, subject to the upfront incentive cap per participant. However, after additional consultation with the EDCs and the storage industry, the CGB may propose to remove formula (2) through the submission of the Program Design Documents, so long as the CGB provides a brief overview of the additional consultation process undertaken to ensure the appropriateness of omitting formula (2).

The Authority directs the CGB to provide notice when a given capacity block is near completion through a compliance filing in the applicable docket(s). Specifically, the CGB shall: (1) set a date for the start of the subsequent step (e.g., first day of the next month); and, (2) notify the market and the Authority that the current step will end on a specific date (e.g., last day of the current month) and that the subsequent step will begin the day after (e.g., first day of the next month). Following the provision of such notice, applications received before the designated end of the current step will receive the level of incentive in that step (e.g., Step 2), while those received after such date will receive the level of incentive in the subsequent step (e.g., Step 3).

Regarding the incentive levels, while the Authority finds the incentive levels proposed by the CGB and listed in Table 2 to be generally acceptable and in line with the Program Objectives, the Authority directs the CGB to adjust the specific incentive levels based on the direction provided in this Decision, specifically Sections III.C.3.b. and IV. Further, as discussed later in this Decision, the Authority will allow *specific* Program participants (i.e., only those specifically identified herein) to request ISO New England, Inc. (ISO-NE) Forward Capacity Market (FCM) project capacity rights, as an incentive adder (<u>See</u>, Section III.D). The CGB shall provide the final residential upfront incentive levels and the corresponding participant incentive formula for Authority review and approval in the first annual Program review proceeding, discussed in Section V.E., no later than October 1, 2021.

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[13] In accordance with the Program Deployment Targets, during the first three-year program cycle (2022-2024) the deployment goal for the residential portion of the Program is 50 MW.

Finally, the Authority directs the Program Administrators to develop rules guiding the distribution of the upfront incentive payment to participating electric storage system owners. The Program Administrators shall include rules to ensure that the upfront incentive cap is not subverted.

a. Low-Income and Underserved Communities Incentive Adder

Multiple stakeholders supported a compensation adder in support of the Program Objective prioritizing increased resilience for customers in environmental justice or economically distressed communities and public housing authorities. The CGB stated that the results of its survey conducted with Guidehouse[14] showed that higher incentive levels are needed to spur electric storage adoption in LMI households, defined as households with less than 100 percent area median income (AMI). CGB RFPD Response, p. 9. The CGB therefore proposed a separate declining block incentive for LMI customers that is twice the value of the non-LMI upfront incentive. Id., p. 10. NECEC and ESA jointly expressed strong support for the CGB's proposed LMI adder, positing that it would ensure equitable participation by customers in underserved and overburdened communities. NECEC/ESA Written Comments, dated January 26, 2021, p. 9. DEEP also strongly supported a higher incentive for LMI customers, but suggested further clarification about customer eligibility is needed. DEEP Written Comments, dated January 26, 2021, pp. 4 and 7. DEEP proposed including customers enrolled in utility hardship programs, LMI customers, and customers of historically marginalized racial and ethnic communities. DEEP Written Exceptions, p. 2. Eversource proposed supporting LMI customer and underserved community participation through enhanced marketing, noting its history of identifying customers through energy efficiency and energy affordability programs including Home Energy Solutions – Income Eligible, New Start, and its Matching Payment Program. Eversource RFPD Response, p. 13. Finally, DEEP suggested that incentive levels be structured to ensure at least 40 percent of installations are at low income households statewide and LMI households in environmental justice communities in order to improve affordability for underserved customers, and consistent with the federal goal that 40 percent of benefits from clean energy investments flow to disadvantaged communities. DEEP Brief, p. 7.

In accordance with the Program Objectives, the Authority finds that an upfront incentive adder is appropriate to prioritize electric storage deployment in low-income households and in underserved communities. The Authority generally agrees with both the CGB and DEEP's proposals to include low-income households statewide and households in underserved communities, particularly given its alignment with the low income and environmental justice community adder offered in the Residential Tariff and Non-Residential Tariff programs authorized in Docket No. 20-07-01 and the Shared Clean Energy Facility (SCEF) program authorized in Docket No. 19-07-01, Review of Statewide Shared Clean Energy Facility Program Requirements. Accordingly, the CGB shall offer the upfront incentive adder to households whose income does not exceed 60 percent of

[14] Guidehouse administered a survey to gather data from previous Residential Solar Investment Program and Smart-E residential program participants on customer interest in and willingness to pay for battery storage. The survey also identified the most valuable aspects of battery storage to customers and key customer demographics. See, CGB RFPD Response, Appendix 1.

the state median income,[15] and households in underserved communities using the environmental justice community definition included in Conn. Gen. Stat. § 22a-20a, distressed municipalities pursuant to Conn. Gen. Stat. § 32-9p, as well as public housing authorities. Conn. Gen. Stat. § 22a-20a defines an environmental justice community as "(A) a United States census block group, as determined in accordance with the most recent United States census, for which thirty per cent or more of the population consists of low income persons who are not institutionalized and have an income below two hundred per cent of the federal poverty level, or (B) a distressed municipality, as defined in subsection (b) of section 32-9p." Pursuant to Conn. Gen. Stat. § 32-9p, the Department of Economic and Community Development identifies municipalities based on its tax base, residents' personal income, and residents' need for public services, and publishes a list of distressed municipalities annually.[16]

Additionally, Public Act 21-48 amended Conn. Gen. Stat. § 16-244z(b) to clarify that hosts of renewable energy projects sited at affordable multifamily housing properties qualify as residential customers. Specifically, Public Act 21-48 expands the definition of 'residential customer' to include:

> a multifamily dwelling consisting of two to four units, or a multifamily dwelling consisting of five or more units, provided in the case of a multifamily dwelling consisting of five or more units, (i) not less than sixty per cent of the units of the multifamily dwelling are occupied by persons and families with income that is not more than sixty per cent of the area median income for the municipality in which it is located, as determined by the United States Department of Housing and Urban Development, or (ii) such multifamily dwelling is determined to be affordable housing by the Public Utilities Regulatory Authority in consultation with the Department of Energy and Environmental Protection, Department of Housing, Connecticut Green Bank, Connecticut Housing Finance Authority and United States Department of Housing and Urban Development.

Conn. Gen. Stat. § 16-244z(b)

For consistency with the Residential Tariff Program, the CGB may offer the upfront low-income and underserved communities incentive adder to multifamily dwellings

[15] The CGB may use the following, as appropriate, to automatically verify eligibility under the 60 percent of state median income criteria for the incentive adder: (1) designated financial hardship by the EDC; (2) receiving Connecticut Energy Assistance Program (CEAP) benefits or otherwise participating in the EDCs' Matching Payment Plan; (3) enrolled in Eversource's New Start Program or UI's Matching Payment Plan (MaPP); (4) has participated in or been income-verified by the Home Energy Solutions – Income Eligible (HES-IE) program in the last three years; or (5) has been verified by the CGB, an EDC, Operation Fuel, or other community partner through another program. The CGB may use other methods to automatically verify eligibility including, but not limited to participation in existing social service programs such as the Supplemental Nutrition Assistance Program (SNAP), Temporary Assistance for Needy Families (TANF), Supplemental Security Income (SSI), and State-Administered General Assistance (SAGA). In the event that the CGB identifies a customer as eligible for hardship designation pursuant to Conn. Gen. Stat. § 16-262c(b)(3)(B), the CGB should direct the customer to the appropriate EDC verification process.

[16] See, Department of Economic and Community Development, Distressed Municipalities, https://portal.ct.gov/DECD/Content/About_DECD/Research-and-Publications/02_Review_Publications/Distressed-Municipalities.

(MUDs) of two to four units that meet the 60 of state median income criteria or are located in an environmental justice community as defined in Conn. Gen. Stat. § 22a-20a. Additionally, the CGB may offer the upfront low-income and underserved communities incentive adder to MUDs of five or more units that are eligible as residential customers for the Residential Tariff program pursuant Conn. Gen. Stat. § 16-244z(b).[17] The CGB shall include all relevant definitions and eligibility criteria in the Program Design Documents submitted for Authority review and approval. The CGB may further investigate and include in the Program Design Documents incentive adjustments and carve outs for MUDs, subject to Authority review and approval, so long as a description of any additions are included with the CGB's submission.

Additionally, in accordance with the Program Objectives and in line with DEEP's proposal, the Program Administrators shall strive to deploy 40 percent of the residential installations in low-income households statewide and LMI households in underserved communities, as defined herein. The Authority will examine progress toward this goal in the Annual and Program Reviews. The Authority will monitor relevant discussions occurring across the state including in other proceedings, documents produced by other state agencies, and proposed and adopted legislation regarding the definitions of LMI residents, underserved communities, and multifamily affordable housing. Accordingly, the Authority may re-evaluate the definitions used for all relevant programs in 2022 and as necessary to appropriately meet the needs of LMI residents and underserved communities.

The Authority directs the CGB to offer residential customers an upfront incentive adder as determined by the eligibility criteria described above, which shall be calculated consistent with the direction provided herein. The CGB shall propose final incentive adders for Authority review and approval in the first annual Program review docket, no later than October 1, 2021, along with a proposed methodology for verifying customer eligibility for the low-income and underserved communities adder, incorporating all guidance provided herein.

2. Commercial and Industrial Upfront Incentive

Multiple stakeholders highlighted the need for a different upfront incentive structure for participating Commercial and Industrial (C&I) customers. CPower proposed upfront incentives that range from $215/kWh to $325/kWh, with no maximum project incentive. CPower Written Comments, dated January 26, 2021, pp. 4-5. AmeriZone asserted that C&I installations may have higher costs, and also suggested that C&I participants should be eligible for low-interest and forgivable loans. AmeriZone Written Comments, dated January 26, 2021, p. 5. Eversource suggested that the total upfront C&I customer incentive should be larger than the residential customer upfront incentive, and the capacity blocks larger, in order to encourage more participation. Tr. 2/1/21, pp. 156-157.

[17] The Authority will incorporate the above changes to Conn. Gen. Stat. § 16-244z(b) into the Residential Tariff Program at a later date. The CGB shall incorporate any findings or additional eligibility criteria added to the Residential Tariff Program for MUDs into the Program authorized herein, notifying the Authority through a relevant compliance filing of the incorporation of such additions.

NECEC proposed the upfront incentive for non-residential electric storage systems be calculated based on the total deployment cost (i.e., capital, installation, and operations and maintenance costs, etc.) minus the expected lifetime project revenues (i.e., performance incentives, demand charge management benefits, ISO-NE revenues, etc.). NECEC Response to CAE-4, p. 1. NECEC also proposed three project size-based incentive tiers, along with three capacity blocks. Id., p. 4. NECEC proposed a $1.6 million incentive cap for a representative 8 MWh project in the first capacity block, which would decline proportionally with each successive capacity block. Id. ESA, Enel X, and Stem generally supported NECEC's C&I upfront incentive proposal.[18]

The CGB recommended one upfront incentive capacity block for the first three-year program cycle, as the federal Investment Tax Credit is scheduled to change, the non-residential energy storage system market is not well developed in the state, and such projects will likely be larger than residential projects. CGB Response to CAE-4. The CGB proposed three tiers of incentives based on customer rate class; Small Commercial (Eversource Rate 30; UI Rate GST), Large Commercial (Eversource Rate 56; UI Rate GST), and Industrial (Eversource Rate 57; UI Rate LPT). CGB Response to CAE-13, C&I PURA Response Materials, p. 7. Specifically, the CGB proposed the following C&I upfront incentives for the first program cycle:

Table 3: CGB Proposed C&I Customer Upfront Incentive Structure (2022-2024)

CAPACITY BLOCK (MW)	EFFECTIVE UPFRONT INCENTIVE ($/KWH)[19]		
	Small Commercial	Large Commercial	Industrial
50.0	$280	$250	$225

The CGB's proposal assumes that C&I customers would not be able to monetize a project's capacity rights, and proposed an incentive cap at 50% of electric storage system cost for all customer classes. CGB Response to CAE-4. The CGB stated that if customers or TPOs are able to monetize capacity rights, incentives should be reduced so ratepayer and societal benefits are maximized. CGB Brief, p. 17.

The Authority agrees that a unique upfront incentive structure is necessary to incentivize non-residential customer participation in the Program. Given the nascent nature of and expected changes to the market conditions noted by the CGB, the Authority finds one capacity block appropriate for the first three-year program cycle. Additionally, the Authority authorizes the upfront incentive to be capped at 50% of electric storage system cost for all C&I customer classes, as recommended by the CGB, and subject to a per project maximum.

[18] See, ESA, Enel X, Stem Responses to CAE-4.

[19] The effective incentive level is adjusted based on kWh capacity using the same formula as the Residential Program area. The upfront incentive is capped at 50% of the cost of the electric storage system for all customer classes.

Regarding the incentive levels, while the Authority finds the incentive levels proposed by the CGB and listed in Table 3 to be generally acceptable and in line with the Program Objectives, the Authority directs the CGB to adjust the specific incentive levels based on the direction provided in this Decision, specifically Sections III.C.3.b. and IV, and propose an upfront incentive limit to be applied on a per project basis. Further, as discussed later in this Decision, the Authority will allow *specific* Program participants (i.e., only those specifically identified herein) to request ISO-NE FCM capacity rights, as an incentive adder (See, Section III.D). The CGB shall provide the final C&I upfront incentive levels and the corresponding participant incentive formula for Authority review and approval in the first annual Program review proceeding, discussed in Section V.E., no later than October 1, 2021.

Finally, the Authority directs the Program Administrators to develop rules guiding the distribution of the upfront incentive payment to participating electric storage system owners. The Program Administrators shall include rules to ensure that the upfront incentive cap is not subverted.

3. Performance Incentive

In addition to an upfront incentive, electric storage systems participating in the Program will be eligible for a performance incentive paid to the storage system based on the average per event reduction across all events in a given season. Participating customers may receive performance incentives for the same electric storage system for up to 10 years. Participating customers shall receive their performance incentive in an annual, lump-sum payment. Customers may transfer their payments to a TPO or another party. The EDCs shall administer the performance incentive with input as needed from the CGB.

a. Summer Performance Incentive

The CGB proposed a performance-based incentive whereby the EDCs or third-party owners (TPOs) would dispatch the electric storage system during appropriate events to maximize transmission and distribution system benefits. CGB RFPD Response, p. 12. The appropriate EDC would distribute the performance-based incentive provided the dispatching entity operated at the specified times. Id. For its benefit-cost analysis (BCA), the CGB adopted the same summer compensation levels as Eversource's Connected Solutions Demand Response (Connected Solutions) program. Id., pp. 26-27 and 30. The key parameters for the Connected Solutions summer performance incentive are included in Table 4.

Table 4: Summer Performance Incentive Parameters (2022-2024)

	SUMMER
Incentive ($/kW)	$225
Season Dates	June 1 – September 30
Number of Events	30-60
Event Duration	3 hours
Timing	2:00 pm – 7:00 pm

Based on the CGB's BCA results discussed in Section IV. of this Decision, the Authority finds that the Eversource Connected Solutions program summer performance incentive level (i.e., $225/kW per summer season[20]) is generally in line with the Program Objectives. However, both Sections III.C.3.b. and IV. of this Decision provide additional direction to the Program Administrators that will impact the final incentive levels and calculations. As such, the Authority directs the Program Administrators to adjust the specific incentive summer performance levels based on the direction provided in this Decision, specifically, sections III.C.3.b. and IV.

The Program Administrators shall provide the final summer incentive levels for Authority review and approval in the first annual Program review proceeding, discussed in Section V.E., no later than October 1, 2021. Additionally, the Authority directs the Program Administrators to jointly develop the appropriate rules to administer the summer performance incentive as described above, and file them in the first annual Program review proceeding for the Authority's review and approval no later than October 1, 2021.

b. Winter Performance Incentive

NECEC and ESA suggested that the Authority consider performance-based incentives for winter events. NECEC/ESA Written Comments, dated January 26, 2021, p. 12. DEEP also supported further consideration of incentives that would reduce natural gas dependence during periods of high energy demand in winter months, and noted that storage could also work to displace oil-burning peaking plants in distressed municipalities used during such times. DEEP Written Comments, dated January 26, 2021, pp. 5 and 8. CGB posited that the cold spell from December 26, 2017 to January 8, 2018, which caused natural gas delivery constraints and forced some dual-fuel generators to switch from natural gas to fuel oil, could motivate an incentive to target winter peaks. CGB Response to CAE-9, pp. 2-3. The CGB stated that while using stored clean energy to offset oil-fueled generation in the winter may support an additional incentive of $3/kW,[21] such a small figure would likely not motivate additional participation. CGB Response to CAE-9. The CGB suggested that the Authority could enable the evaluation of a possible winter dispatch benefit through a $25/kW-$50/kW performance incentive, similar to that of other regional programs. Id. The CGB stated that reducing the summer peak performance-based incentive by an amount equal to any adopted winter peak

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[20] Based on the average kW used per event, averaged over the season.

[21] See, CGB Response to CAE-8 for further explanation.

performance-based incentive would not materially impact the value to the participant (i.e., PCT), but would result in a higher societal benefit (i.e., SCT) if marginal winter emissions are in fact reduced, in addition to other benefits. Id.

Given the stakeholder support for targeting the reduction of oil-fueled generation in winter months, the Authority finds that a winter peak period performance-based incentive is appropriate. Specifically, the Authority determines that an active winter dispatch incentive presents significant potential benefits, particularly for municipalities that suffer disproportionate health impacts from oil-burning peaking generation units. Accordingly, the EDCs shall offer participating electric storage system customers a performance incentive of $50/kW per winter season during the winter season,[22] during which the storage system is dispatched for the first three-year program cycle (2022-2024), in line with Eversource's current Connected Solutions program. The key parameters for the winter performance incentive are shown in Table 5.

Table 5: Winter Performance Incentive Parameters (2022-2024)

	WINTER
Incentive ($/kW)	$50
Season Dates	December 1 – March 31
Number of Events	5
Event Duration	3 hours
Timing	2:00 pm – 7:00 pm

The Authority directs the Program Administrators to jointly develop the appropriate rules to incorporate the winter performance incentive into the summer performance incentive administration rules described in Section III.C.3.a. above.

4. Front-of-the-Meter Considerations

The Authority requested incentive structures for front-of-the-meter (FTM) sited projects, and received one proposal specific to such projects from Key Capture Energy (Key Capture). Key Capture provided four proposed options for consideration, with varying Program incentive and wholesale market participation eligibility. Key Capture Response to CAE-5. Key Capture also stated that non-coincident peak demand charges make projects unviable and assumed such charges were eliminated. Tr. 2/26/21, pp. 258-261. Additionally, NECEC indicated its proposed C&I incentive structure would be applicable to both BTM and FTM projects, but different considerations may be necessary for non-customer sited FTM projects. Tr. 2/26/21, pp. 241-242. ESA asserted that compensation levels should be different for large FTM projects, but that more discussion is needed to fully develop an appropriate Program design. ESA Response to CAE-5. The CGB also noted that the FTM marketplace is more complex, and proposed that the Authority consider a DEEP-administered competitive procurement. CGB Brief, pp. 25-26. Alternatively, the CGB proposed introducing a low upfront incentive that increases until

[22] Based on the average kW used per event, averaged over the season.

developers pursue FTM projects, or allowing the active dispatch performance incentive to serve as a "back stop" if market revenues are not sufficient. Id. The CGB also recommended a more comprehensive discussion on the Program parameters for FTM systems. Id.

Key Capture proposed the following four options for the Authority's consideration, shown in Table 6: two options where the storage system would operate according to the guidelines contemplated in the Authority's Straw Proposal; and two options where the storage system would be permitted to participate in wholesale markets. Key Capture Response to CAE-5. Option one combines upfront and performance incentives slightly lower than those proposed by the CGB for BTM systems to reflect economies of scale inherent to larger projects, while option two contains only a performance incentive. Id. Option three combines further reduced upfront and performance incentives, to reflect the additional value streams that would be available to systems participating in energy markets, while option four contains only an upfront incentive. Id. Key Capture noted its proposed incentives would be for the first program year, and supported a declining block structure to provide certainty for developers as the industry matures. Id.

Table 6: Key Capture FTM Project Incentive Proposal

	Description	Upfront Incentive ($/kWh)	Performance Incentive ($/kW-yr)	Term (yrs)	Per-Project Incentive Cap ($)[23]	Operational Model
1	Upfront + Performance	$70	$80	10	$2.8MM	Storage operates according to prescribed program guidelines
2	Performance Only	-	$95	10	N/A	
3	Reduced Upfront + Performance	$35	$25	10	$1.4MM	Storage is allowed full wholesale market participation
4	Upfront Only	$90	-	-	$3.6MM	

Key Capture Response to CAE-5.

Concerning the issue of demand charges, Key Capture provided the following example: "in Eversource's service territory today under Rate 58, the noncoincident peak C&I demand charges that would apply to a front-of-the-meter large scale battery storage project would make it uneconomic to run." Tr. 2/26/21, p. 259. Key Capture also pointed to New York as a jurisdiction that is addressing demand charges, potentially by eliminating them, in order to lower barriers to entry for FTM electric storage systems. Id. Key Capture provided a New York Department of Public Service whitepaper on the topic. Key Capture Correspondence, dated March 5, 2021.

Based on the foregoing, the Authority finds demand charges to be a barrier to the deployment of FTM standalone electric storage systems. Such systems were explicitly included in the language of PA 21-53. Accordingly, the Authority directs the EDCs to

[23] Per project incentive caps are based on the equivalent upfront incentive that would be issued to a 20 MW/40 MWh system.

develop a revenue-neutral tariff rider for FTM electric storage systems that does not contain a demand charge, to be submitted for consideration in the first annual Program review proceeding, discussed in Section V.E., no later than October 1, 2021. The tariff riders submitted by the EDCs shall be implemented and made effective on or before January 1, 2022.

Regarding Key Capture's proposed incentive structure, the Authority finds that additional analysis and stakeholder input is required to ensure that all barriers to entry, market opportunities, and programs are fully understood, particularly in light of Section 3 of Public Act 21-53, which authorizes DEEP to procure electric storage systems and the Authority's above direction to implement a FTM storage tariff rider effective January 1, 2022. Therefore, the Authority directs the CGB take the following steps:

- Perform BCAs of Key Capture's proposed options one through four. See, Key Capture Response to CAE-5. The CGB should consult with FTM electric storage stakeholders to further refine any parameters needed to calculate the complete BCAs.
- The CGB should consult with FTM electric storage stakeholders, DEEP, the EDCs, and wholesale market participants to better understand the barriers to entry, market opportunities, and programs for FTM standalone electric storage systems.

The CGB shall provide the results of the above ordered actions, including a recommended path forward on or before June 1, 2022, which will be considered in the appropriate annual Program review proceeding. The Authority intends to solicit stakeholder feedback on the CGB's recommendations and other solutions to FTM storage deployment in such proceeding.[24]

D. PROGRAM ELIGIBILITY

The following criteria must be met for customer participation in the Program:

- Eligible customers must be an electric customer, residential, commercial, or industrial, of one of the State's two EDCs;
- The service address for a residential or C&I customer electric account must be for a physical address located within the state of Connecticut;
- The residence or C&I building/facility must be connected to the electric grid by agreement with the EDCs;
- The electric storage system must be new to the customer residence or C&I building/facility as of January 1, 2022. Systems installed prior to January 1, 2022 shall only be eligible for the performance incentive portion of the Program.
- The CGB may establish rules requiring residential customers installing standalone storage systems to complete the EDC-administered Home Energy Solutions (HES) or Home Energy Solutions – Income Eligible (HES-IE) assessment to

[24] Deployment of FTM electric storage systems under the Program authorized herein would not decrease the 580 MW deployment target for participating residential and commercial and industrial customers. In other words, FTM storage deployment under this program is above and beyond the deployment targets outlined in Section III.B.

receive an upfront incentive. If such rules are established, the assessment shall not need to be completed prior to the electric storage system's installation and shall be included in the relevant Program Design Documents filed for Authority review and approval.

The Program will allow for both standalone electric storage systems and energy storage systems coupled or co-located with other energy resources (e.g., solar), if such configurations are also in compliance with EDC interconnection agreements. Both alternating current ("AC") and direct current ("DC")-coupled battery systems are eligible for the Program. The following technical criteria must also be met:

- The electric storage system must be grid-tied;
- All components must utilize commercially available electric storage technologies approved for use by the Authority;
- The customer and any contractors must abide by the most recent version of the applicable EDC's interconnection guidelines;
- To receive an upfront incentive, the electric storage system must be set to the passive dispatch default settings, subject to the parameters, including exceptions, detailed in this Decision and an audit over the course of the useful life of the electric storage system; and,
- To receive ongoing performance incentives, the electric storage system must be actively dispatched in accordance with the rules determined by the EDCs and approved by PURA.

Last, while electric storage system operators will be required to adopt the passive dispatch settings established pursuant to this Decision, they may operate outside such passive dispatch parameters in three circumstances: (1) during emergency events, as determined by the Program Administrators and/or participant; (2) during active dispatch events as determined by the relevant EDC; and (3) to meet any ISO-NE or other obligations (<u>See</u>, Section III.D.1. for the four cases in which projects are eligible to participate in the ISO-NE FCM). All participants shall be required to provide an affidavit or equivalent asserting compliance with the passive dispatch settings except for the three scenarios listed above.

1. ISO-New England Market Participation

The Authority's Straw Proposal proposed requiring all participating electric storage systems to transfer the ownership of capacity rights to the CGB. Straw Proposal, p. 5. The CGB further stated that benefit-cost ratios are higher for projects that do not participate in the ISO-NE FCM, showing the higher value of electric storage demand response benefits. CGB Response to CAE-11, p.1. The CGB also noted that if all capacity rights are owned by the Program Administrators, the corresponding revenues flow to ratepayers rather than directly to the participant. Tr. 2/26/21, pp. 106-107. The CGB suggested that the Program should prioritize ratepayer and societal benefits while enabling maximized participant incentives, instead of maximizing participant profits. CGB Brief, p. 17. Further, the CGB stated that if the TPOs can receive capacity market revenues, the resulting benefits should accrue to underserved populations in order to achieve societal benefits. Tr. 2/26/21, pp. 86-87. DEEP supported requiring participants to transfer capacity rights, noting that such an arrangement would contribute significant ratepayer value. DEEP Written Comments, dated January 26, 2021, pp. 6-7. DEEP also proposed the capacity rights be transferred to the EDCs instead of the CGB. Id.

NECEC and ESA, meanwhile, asserted that transferring capacity rights to the CGB would create financing and operational risk, as it removes a potential project revenue stream and could create conflicting operational schedules between the customer's intended usage and the capacity right holder's obligations, as well as between the active and passive dispatch schedules. NECEC/ESA Brief, p. 4. UI supported transferring capacity rights to TPOs to bid into the applicable ISO-NE markets, but proposed TPOs be required to share a portion of the resulting revenue with the Program Administrators to offset program costs and minimize ratepayer impact. UI Brief, p. 12. UI further proposed that the active demand response requirement should always supersede any TPO's ISO-NE obligations. Id. Stem asserted that energy storage operators would seek to optimize market signals and overall value, possibly providing multiple types of benefits to the electric grid. Stem Response to CAE-2.

The Authority appreciates that the potential revenue stream from ISO-NE market participation would improve project economics for TPOs. However, the Authority also understands that, based on the analysis provided in this proceeding, the retention of the capacity rights (i.e., the inability for storage projects to monetize the associated capacity rights) increases ratepayer value. In order to ensure ratepayer benefits, as represented in the RIM and discussed in Section IV., the Authority authorizes the project owner or TPO, as appropriate, to retain capacity rights without the ability to monetize such rights (i.e., participation in the ISO-NE FCM) as the default Program arrangement.[25]

However, in the four select cases described below, TPOs and residential and C&I customers will be permitted to both retain and monetize a project's capacity rights. The four cases outlined below support the public policy goals outlined in the Program Objectives, namely the objective to increase local and community resilience and to prioritize delivering increased resilience to critical facilities and customers on the grid edge who consistently experience more and/or longer than average outages during major storms. See, Section III.A.

Finally, the Authority directs the Program Administrators to jointly develop the appropriate rules to administer the treatment of capacity rights as described in this section, and file them in the first annual Program review proceeding for the Authority's review and approval no later than October 1, 2021.

a. Customers on the Grid Edge

The Authority finds that allowing TPOs to retain the capacity rights for projects located on the grid edge will better align the Program with its Objectives outlined in Section III.A. Specifically, allowing TPOs to retain capacity rights for projects on the grid edge will appropriately prioritize delivering increased resilience to customers who consistently experience more and/or longer than average outages during major storms.

[25] Stakeholders may propose a method to calculate and implement a process whereby participants may purchase the ability to use a project's capacity rights during the 2022 Annual Review.

Accordingly, the CGB shall allow TPOs to request capacity rights for projects located on the grid edge through the Program application process.

Through CAE-21, 22, 23, and 24, the Authority directed the EDCs to identify the following data:

- Identify which zip codes, on average, have experienced more outages per customer during major storms[26] than other zip codes since July 1, 2012. Provide a list of the total number of outages due to major storms since July 1, 2012, by zip code, as well as the number of customers in each zip code.
- Identify which zip codes, on average, have experienced longer outages per customer during major storms than other zip codes since July 1, 2012. Provide a list of the total duration of outages due to major storms since July 1, 2012, by zip code, as well as the number of customers in each zip code.
- Identify which circuits, on average, have experienced more outages per customer during major storms than other circuits since July 1, 2012. Provide a list of the total number of outages due to major storms since July 1, 2012, by circuit and zip code, as well as the number of customers on each circuit.
- Identify which circuits, on average, have experienced longer outages per customer during major storms than other circuits since July 1, 2012. Provide a list of the total duration of outages due to major storms since July 1, 2012, by circuit and zip code, as well as the number of customers on each circuit.

Based on the EDCs' responses, the Authority determines that, for purposes of the Program, Grid Edge shall be defined as (1) the top ten percent of circuits with the highest number of outages per customer during major storms since July 1, 2012, and (2) the top ten percent of circuits with the longest outages due to major storms since July 1, 2012. The EDCs shall develop maps of locations (i.e., the relevant circuits) that meet the above criteria, with zip codes included for reference, to be submitted for Authority review and approval no later than October 1, 2021. Further, the EDCs shall update the final approved maps on an annual basis, and shall include such maps in all relevant Program documentation, including on the EDCs' respective Program webpages.

b. Critical Facilities

AmeriZone noted that some C&I customers require backup power during outages in order to maintain their service, such as supermarkets and housing authorities. Tr. 2/1/21, pp. 104-105. AmeriZone stated that such companies typically install traditional fossil fuel generators, which are dirty and do not provide any value to the facility outside of outages. Id. AmeriZone therefore proposed higher incentives for "essential business serving LMI communities." AmeriZone RFPD Response, p. 3. AmeriZone further asserted that such "critical facilities" require greater resilience, and suggested additional

[26] "Major storm" is defined in the Decision in Docket No. 86-12-03, dated March 22, 1995, p.2, as follows: "major storm exclusion criterion [that] is based on a statistical analysis of the most recent four calendar years of reliability data. A cumulative frequency distribution of the number of locations requiring service restoration work per day would be calculated for this four-year period. Whenever the frequency of restoration work locations exceeds the 98.5 percentile, by company and/or region, the major storm criterion would be met."

incentives for qualifying customers would encourage businesses to add resiliency to their operations. Tr. 2/1/21, p. 116.

The Authority directed the EDCs to provide lists of all critical facilities known to the Companies as defined in Conn. Gen. Stat. § 16-243y(a)(2), as well as known facilities that were designated essential by the Connecticut Department of Economic and Community Development (DECD) pursuant to Governor Lamont's Executive Order 7H, commercial customers located in targeted investment communities, public investment communities, or Neighborhood Revitalization Zones, and public housing authorities as defined by Conn. Gen. Stat § 8-39. See, Interrogatory CAE-24. In response, Eversource provided a list of critical facilities, essential facilities, and public housing authorities, and stated it "does not maintain a list of targeted investment communities, public investment communities or Neighborhood Revitalization Zone and public housing authorities." Eversource Response to Interrogatory CAE-24. UI provided its list of critical facilities that are submitted by municipalities. UI Response to Interrogatory CAE-24.

The Authority agrees that incentivizing critical facilities that require backup power during outages to adopt electric storage systems would provide important, incremental benefits, which supports the Authority's Objective to provide local community resilience, as discussed in Section III.A. For the purposes of the Program, Critical Facilities shall be defined according to Conn. Gen. Stat. § 16-243y(a)(2), as well as known facilities that were designated essential by the DECD pursuant to Governor Lamont's Executive Order 7H. The Authority accordingly directs the CGB to allow customers to request capacity rights for projects for Critical Facilities through the Program application process. Additionally, the Authority requires such customers to submit a Resiliency Plan in which the customer shall demonstrate how their system would be recharged when grid-charging is otherwise unavailable. The Program Administrators shall develop a template Resiliency Plan for eligible customers to retain the capacity rights associated with their project. The Program Administrators shall consult AmeriZone and other interested stakeholders in developing the template plan. Lastly, the Program Administrators shall develop a process to receive a customer's Resiliency Plan, integrating it into the application process discussed in Section IV.B. The Program Administrators shall submit the Resiliency Plan template and proposed application process for the Authority's review and approval no later than December 15, 2021.

c. C&I Customers with Fossil Fuel Generators

AmeriZone proposed higher incentives for customers that "retire an existing diesel or natural gas generator and replace it with a battery system." AmeriZone RFPD Response, p. 3. As discussed above, AmeriZone also asserted that fossil fuel generators do not typically provide value to customers outside of outages. Tr. 2/1/21, pp. 104-105. AmeriZone further proposed that the Program require participants to submit a "long-term resiliency plan in the event of a multi-day outage" as part of the application process. AmeriZone RFPD Response, p. 2. Participants would need to "demonstrate how their battery system will be deployed, and how it will be recharged when grid-charging is otherwise unavailable." Id. Such requirements would qualify systems for incentive adders, particularly if participants could show systems would be recharged with renewable energy (e.g., solar). AmeriZone proposed that participants that fail to follow through on the resiliency plan would be required to repay any Program incentives they received. Id., pp. 5-6.

In support of the Program Objectives to provide multiple types of benefits to the electric grid, namely customer resilience and maximizing the long-term environmental benefits of electric storage, the Authority determines that an additional incentive is appropriate to incentivize customers to replace existing fossil fuel generators. Accordingly, the Authority directs the CGB to allow C&I customers to request capacity rights for electric storage projects that are replacing existing fossil fuel generators through the Program application process. Additionally, the Authority requires such customers to submit a Resiliency Plan in which customers shall demonstrate how their system would be recharged when grid-charging is otherwise unavailable and provide proof that the fossil fuel generator being replaced will be decommissioned. The Program Administrators shall develop a template Resiliency Plan for eligible customers to retain the capacity rights associated with their project. The Program Administrators shall consult AmeriZone and other interested stakeholders in developing the template plan. Lastly, the Program Administrators shall develop a process to receive a customer's Resiliency Plan, integrating it into the application process discussed in Section IV.B. The Program Administrators shall submit the Resiliency Plan template and proposed application process for the Authority's review and approval no later than December 15, 2021.

d. Small Business Customers

Small business customers shall also be able to request capacity rights for projects. In alignment with the Shared Clean Energy Facility Program authorized in Docket No. 19-07-01, Review of Statewide Shared Clean Energy Facility Program Requirements, Small Business Customer means a commercial or industrial electric customer with less than a 200 kW peak load.[27] The Authority directs the CGB to allow Small Business Customers to request capacity rights for electric storage projects. Additionally, the Authority requires such customers to submit a Resiliency Plan in which said customer shall demonstrate how their system would be recharged when grid-charging is otherwise unavailable. The Program Administrators shall develop a template Resiliency Plan for eligible customers to retain the capacity rights associated with their project. The Program Administrators shall work with AmeriZone other interested stakeholders to develop the template plan. Lastly, the Program Administrators shall develop a process to receive a customer's Resiliency Plan, integrating it into the application process discussed in Section IV.B. The Program Administrators shall submit the Resiliency Plan template and proposed application process for the Authority's review and approval no later than December 15, 2021.

[27] See, Docket No. 19-07-01, Review of Statewide Shared Clean Energy Facility Program Requirements, Final Decision Exhibit B – Modified SCEF Program Requirements, p. 4. http://www.dpuc.state.ct.us/dockcurr.nsf/8e6fc37a54110e3e852576190052b64d/2c2724a6374a05a3852584d4006bd716/$FILE/190701%20(Exhibit%20B-Modified%20SCEF%20Program%20Requirements)-121819.pdf

2. Active Dispatch

To receive ongoing performance incentives, the electric storage system must be actively dispatched in accordance with the operational control model described in Section III.F. Projects that request and receive the ability to monetize the capacity rights, pursuant to the eligibility requirements outlined in Section II.D.1. above, may be eligible for the upfront incentive but may be unable to respond to an active dispatch event due to ISO-NE obligations. The projects that do not participate in an active demand response event will not receive the corresponding performance incentive. For clarity, all electric storage systems participating in the Program *must* enroll in and communicate with the active dispatch aspect of the program. However, systems that are authorized to participate in the ISO-NE FCM will be permitted to respond to those market signals, so long as all requirements under the operational control model are met. The EDCs shall develop the final active dispatch guidelines, incorporating the guidance in Section III.C.3, to be submitted for Authority review and approval no later than October 1, 2021.

3. Passive Dispatch

The CGB proposed that energy storage systems receiving the upfront incentive be required to maintain default passive dispatch settings to ensure the system performs during the ISO-NE summer peak period. CGB RFPD Response, p. 10. Specifically, participants would be required to "set the electric storage system to automatically store and dispatch … energy through the battery to reduce demand during ISO-NE summer peak periods which currently includes June through August weekdays from 1:00 to 5:00 p.m. using no more than 80% of the battery storage capability (i.e., at least 20% will be reserved for back-up power)." Id. The CGB stated that such settings would automatically store and dispatch energy to meet customer load during the ISO-NE summer peak period. Id., p. 12. The resulting benefits to ratepayers include avoided generation capacity, avoided transmission and distribution capacity, improved reliability, and lower ISO-NE capacity market clearing prices through demand reduction induced price effects. Id., pp. 80-83. See, Section IV.

Stem asserted that requiring passive dispatch settings may not be optimal, noting that the settings contemplated in the Authority's Straw Proposal would only target load shifting to smooth system peaks, which may not always be the highest value grid service. Stem Response to CAE-2, dated February 19, 2021. Stem also stated that multiple market signals, including rate structures, utility programs, and wholesale markets, provide grid benefits by definition. Stem Response to CAE-1, dated February 19, 2021. Stem proposed that electric storage systems could opt for the passive dispatch settings, but should be able to utilize other existing options that provide grid and customer value. Id. Stem asserted that such flexibility would allow the storage system operator to maximize the system's value through multiple market signals, likely creating more overall value from the resource than the passive dispatch settings. Stem Response to CAE-2, dated February 19, 2021. Stem further maintained that the program administrator is unable to optimize specific customer value streams, which would harm such customers. Tr. 2/1/21, p. 206.

The Authority finds that requiring passive dispatch settings guarantees ratepayer benefits, as demonstrated by the results of the RIM outlined in Section IV. The Authority adopts the CGB's proposed passive dispatch settings described above as the default arrangement for participating electric storage systems; namely, participants shall set electric storage systems to automatically store and dispatch energy during ISO-NE summer peak periods, which currently includes weekdays June through August from 1:00 p.m. to 5:00 p.m., or another time period to be determined by the CGB and approved by PURA. In the event that an active dispatch event is called by the EDCs during the passive dispatch hours, the active dispatch shall take precedence over the passive dispatch. As discussed in Section V.A., the CGB shall be responsible for determining the passive dispatch settings in consultation with the EDCs. Accordingly, the CGB shall develop the final guidelines governing the passive dispatch as part of the Program Design Documents, incorporating all guidance from Section III.D., to be submitted for Authority review and approval no later than October 1, 2021. The proposed Program Design Documents shall include a requirement that all Program participants provide an affidavit or equivalent asserting compliance with the passive dispatch guidelines.

The Authority appreciates that other revenue streams may also be able to provide grid, societal, or other benefits. Specifically, the Authority understands that participating in different ISO-NE markets (e.g., ancillary services market) may provide greater grid or societal benefits than the passive demand response settings. The Program design established herein does not preclude energy storage devices from participating in ISO-NE ancillary service markets that allow participation by load reducers.[28] Accordingly, such projects shall be permitted to operate outside the passive dispatch settings in order to satisfy any ISO-NE market obligations. For clarify, projects shall operate under the passive dispatch settings to the furthest possible extent, but can override the baseline settings in order to satisfy any ISO-NE market requirements. Accordingly, the CGB shall develop a process to verify participation in the ISO-NE markets in order to better understand how such participation impacts the expected Program benefit-cost ratios and any implications for the Program's active and passive dispatch settings. The CGB shall include such verification process as part of the Program Design Documents, incorporating all guidance from Section III.D., to be submitted for Authority review and approval no later than October 1, 2021.

Last, projects may also operate outside of the established passive dispatch settings established pursuant to this Decision in preparation for and during emergency events. The Program Administrators shall develop parameters for how and when this exception to following the passive dispatch settings (i.e., preparation and response to an emergency event) applies. The CGB shall include such parameters as part of the Program Design Documents to be submitted for Authority review and approval no later than October 1, 2021.

a. Emissions Impacts

The Institute for Policy Integrity at NYU School of Law (Policy Integrity) and WattTime stated that while energy storage systems are important for reducing carbon emissions by supporting variable renewable energy sources, operation can increase emissions if use is not designed properly. Policy Integrity and WattTime Written

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[28] If classification as a load reducer presents a barrier to meeting the Program Objectives (See, Section III.A.), stakeholders may propose potential solutions during the 2022 Annual Review process.

Comments, dated January 26, 2021, p. 1. Policy Integrity and WattTime noted that both battery efficiency losses and charge and discharge timing can lead to higher emissions than otherwise would have occurred. Id., p. 2. WattTime provided an analysis of the five-minute marginal emission rate data for the ISO-NE Connecticut sub-region, which it stated implied that an energy storage system that charges at night and discharges from 2 p.m. – 7 p.m. would increase emissions since the marginal operating emission rate at night is higher than during the peak 2 p.m. – 7 p.m. period. Id., pp. 2-3. WattTime proposed the Authority direct the EDCs to collect emissions data (CO_2, NO_x SO_x) at the most granular level practicable in order to inform an analysis of the Program's emission impacts. Id., pp. 5-6.

Additionally, the CGB's analysis stated that the net emissions impact of the Straw Proposal is driven by the passive dispatch settings of participating energy storage systems. CGB Response to CAE-8. The CGB estimated its proposed passive dispatch settings would increase emissions by approximately 245 lb. CO_2 per ISO-NE summer season and 242 lb. CO_2 per ISO-NE winter season for each standalone residential system, and 239 lb. CO_2 per ISO-NE summer season and 224 lb. CO_2 per ISO-NE winter season for each PV-paired residential system. Id. The CGB stated that, because the calculation assumes that charging and discharging occurs at the same marginal emissions rate, energy storage systems' efficiency losses drive a net increase in emissions. Tr. 2/26/21, pp. 49-50. Further, the CGB noted more granular emissions data would likely indicate greater emission reductions attributable to the Program. Id., pp. 50-51. The CGB also noted that as the grid becomes cleaner, electric storage will play an important role in shifting renewable power to other times of the day. Id., p. 45.

Stem stated that electric storage systems participating in California's Self Generation Incentive Program receive a grid-level greenhouse gas emissions signal, updated every five minutes, and are required to reduce emissions on an annual basis. Tr. 2/1/21, pp. 211-214. Stem stated that the emissions signal is provided by WattTime through the storage device's software. Id.

As the ISO-NE electric grid is expected to introduce significant intermittent generation capacity in the near future, the Authority also expects electric storage systems deployed through the Program will likely play an important role in shifting low-emission energy generation to other times of the day. The Authority is therefore interested in more fully understanding the emissions impacts of the Program, particularly as the ISO-NE generation mix changes. Accordingly, and consistent with the Authority's objective to maximize the long-term environmental benefits of electric storage, the Authority directs the CGB to further evaluate ways to increase the emission reductions associated with the Program. The CGB shall consult with outside marginal emissions data experts, specifically consulting at least WattTime, and DEEP to more fully quantify the Program's emissions impacts. The CGB shall report its findings on or before August 1, 2022, including any recommendations for better optimizing the emissions reductions achievable by the Program and the resulting impact on the BCA test, in the appropriate annual Program review docket so the Authority can consider modifying the passive dispatch setting beyond Year 1 for all electric storage systems.

4. Technology Eligibility

In order to ensure robust and sustained Program participation, the Authority directs the EDCs to qualify as many commercially available inverters and storage systems as possible. The EDCs shall provide annual compliance updates through the annual Program review docket on the device qualification status, including a list of all known qualified and non-qualified technology. The EDCs shall also maintain a single list of eligible electric storage technologies, to be updated on an ongoing, rolling basis. Storage technologies shall be considered (and approved or not approved) for inclusion as eligible based on their ability to satisfy program requirements and objectives, including, but not limited to, the following:

- Commercially available technologies with appropriate technical certifications, reflecting adequate capabilities, testing and quality control with respect to industry standards[29];
- Ability to meet the passive and active dispatch needs of the Program, including existing or intended software integration with dispatch platforms utilized in the program, and ability for technology to receive remote software upgrades;
- Safety considerations, and other characteristics including:
    a. 70% roundtrip efficiency or greater;[30]
    b. 10-year warranty or equivalent; and,
    c. 10-year system life or equivalent.
- Customer service and technical support provided by battery manufacturer.

The EDCs shall develop an initial list of eligible electric storage technologies, to be submitted for Authority review and approval no later than October 1, 2021. The EDCs shall include the list in all relevant program documentation, as well as on Power Clerk (or other similar least-cost system) and their respective websites. Any updates to the list must be submitted during the Annual or Program Review, as applicable. [31]

E. OWNERSHIP MODEL

So long as the eligibility requirements outlined in Section III.D. are satisfied for the duration of the system's participation in the Program, eligible customers may own the participating electric storage system. TPOs may also own a participating electric storage system so long as: (1) the eligibility requirements outlined in Section III.D. are satisfied for the duration of the system's participation in the Program; (2) the TPO actively

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[29] In determining availability, the EDCs may consider the list of batteries approved by the California Energy Commission. See, https://www.energy.ca.gov/programs-and-topics/programs/solar-equipment-lists.

[30] Roundtrip efficiency is a ratio of the difference between kWh used to charge the system and kWh discharged from the system, including electrical losses. The Program Administrators may verify a system's efficiency by reviewing its interval data.

[31] The Authority appreciates UI's Supplement to Oral Argument dated July 19, 2021 regarding its ability to meet the Program start date of January 1, 2022. An interim technology solution may be appropriate, so long as it meets the requirements of this Decision. All costs incurred will be subject to a full prudency review in the appropriate proceeding (i.e. 22-01-04 and 23-01-04). Additionally, the initial list of eligible storage technologies may reflect systems compatible with UI's existing DERMS, and updates to the list resulting from any new DERMS shall be submitted for Authority review in the applicable proceeding before the operational date of such new DERMS.

dispatches the electric storage system in accordance with the rules and/or information provided by the EDCs; and (3) the Program Administrators have determined that the TPO has the technical, financial, and managerial capabilities to own and operate, if requested, electric storage systems.

The Program Administrators shall establish a process for certifying TPOs as technically, financially, and managerially capable of owning and operating electric storage systems. The Program Administrators shall develop the appropriate program rules and submit such program rules and/or documents for the Authority's approval on or before October 1, 2021. In its October 1, 2021 filing, the Program Administrators may also recommend pre-approval or fast track approval of certain developers already known to be developing energy storage systems in Connecticut.

F. OPERATIONAL CONTROL MODEL

Eversource proposed an operational control model whereby enrolled customers are registered in an existing dispatch control system. Eversource Written Comments, dated January 26, 2021, p. 11. The EDC would then send active dispatch signals through the device's original equipment manufacturer (OEM) platform or a third-party DER aggregator, which would then communicate directly with the device itself. Id. The CGB supported an operational control model whereby the EDCs act as the central dispatcher through a competitively sourced Demand Response Management System (DRMS) (e.g., Energy Hub). Tr. 2/1/21, p. 26; CGB Brief, pp. 15-16. Additionally, NECEC supported the Eversource proposal, and noted that a similar model has been implemented successfully in other jurisdictions, namely Eversource's Connected Solutions program in Massachusetts. NECEC Response to CAE-6. UI also recommended the Authority adopt Eversource's Connected Solutions control model, and noted that it intends to utilize a dispatch platform such a Virtual Peaker or Energy Hub to make operational decisions. Tr. 3/17/21, p. 120; UI Brief, pp. 3-4, UI Written Comments, dated January 26, 2021, p. 9. Stem similarly proposed that the EDCs send a signal to the energy storage system operator, who can then dispatch the system based on their individual value. Tr. 2/1/21, p. 207. Stem noted that such a proposal aligns with the California Self-Generation Incentive Program and Eversource's Connected Solutions Program. Tr. 2/1/21, pp. 236-237. Through CAE-06, the Authority sought confirmation from the CGB and the solar industry that it supports the Eversource operational control model. In addition to the CGB, Stem, and NECEC, ESA, Enel North America, Inc., Sunrun Inc., and AmeriZone, LLC expressed support for Eversource's proposed operational control model. The Authority received no comments expressing dissent or concern regarding Eversource's proposal.

Given the stakeholder support for Eversource's proposal, the Authority directs the EDCs to work with the CGB to finalize an operational control model as defined in Eversource's Connected Solutions program, whereby customers are registered in a dispatch control system in which the EDC sends signals to an OEM or third-party platform, leaving last-mile communication with the battery system or third party owner or manufacturer. The resulting rules shall also establish an application process for enrolling customers in the active demand response portion of the Program. The Program Administrators shall jointly submit the resulting operational control guidelines and associated documents for the Authority's review and approval on or before October 1, 2021.

In addition, the EDCs shall separately submit no later than January 1, 2022 a comprehensive description of their existing demand response management system (DRMS) and distributed energy resource management system (DERMS) platforms, including the difference between the different systems. See, Eversource and UI Responses to CAE-18. Such filing shall include, but not be limited to, a detailed description of the procurement process and timeline, as well as upfront and ongoing system costs, clearly delineated and explained. The EDCs shall also describe how the costs for such systems are paid for by ratepayers (i.e., through which rate component or rate mechanism have cost been recovered, how much of the cost been recovered to date, how will the remaining cost be recovered, etc.). The Authority reserves the right to further consider the costs and ratepayer impacts of such systems in the 2022 Annual Review proceeding.

IV. BENEFIT-COST ANALYSIS

The benefits and costs of multiple statewide energy storage program designs were analyzed through the instant proceeding. Various benefit-cost analysis methodologies are utilized nationally to "plan, prioritize, and assess energy efficiency and distributed energy resource programs." CGB Brief, pp. 17-18. In Connecticut, DEEP and the EDCs have historically applied benefit-cost methodologies to evaluate electric and gas conservation measures for the Conservation and Load Management (C&LM) Plan. As noted in the 2021 Plan Update to the 2019-2020 Conservation & Load Management Plan, both the Utility Cost Test (UCT), which includes utility-specific benefits and associated program costs, and the Total Resource Cost Test (TRC), which includes all energy and non-energy benefits, have been used in Connecticut since 2015 to determine cost-effectiveness.[32] In addition to the TRC and Program Administrator Cost Test (also called the UCT), the CGB calculated benefit-cost ratios using the Participant Cost Test (PCT), Societal Cost Test (SCT), and the Ratepayer Impact Measure (RIM) cost test.[33] Each benefit-cost test includes multiple categories of benefits and costs, which the CGB defined as follows, consistent with the C&LM Plan:

- Avoided Energy
  - Changes in energy purchases in the ISO-NE wholesale market due to changes in energy consumption. The annual energy savings by ISO-NE costing period based on energy storage dispatch profiles, according to the value of Avoided Energy in Connecticut from the Avoided Energy Supply Components in New England: 2021 Report (AESC).[34]

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[32] See, 2021 Plan Update to the 2019-2020 Conservation & Load Management Plan, https://portal.ct.gov/-/media/DEEP/energy/ConserLoadMgmt/FINAL-2021-Plan-Update-Filed-10302020.pdf, pp. 39-44.

[33] For more information on these cost tests, see, Understanding Cost-Effectiveness of Energy Efficiency Programs: Best Practices, Technical Methods, and Emerging Issues for Policy Makers, Energy and Environmental Economics, Inc. and Regulatory Assistance Project, dated November 2008, https://www.epa.gov/sites/production/files/2015-08/documents/cost-effectiveness.pdf.

[34] See, Avoided Energy Supply Components in New England: 2021 Report, https://www.synapse-energy.com/sites/default/files/AESC_2021_.pdf.

- Avoided Generation Capacity
    - Changes in levels of power contracted in the ISO-NE forward capacity market due to changes in peak demand. The average annual peak savings during the ISO-NE peak capacity hours based on energy storage dispatch profiles, according to the value of Avoided Generation Capacity in Connecticut from the AESC.

- Avoided Transmission and Distribution (T&D) Capacity
    - Changes in transmission and distribution infrastructure investments that would otherwise be necessary to meet peak demand due to changes in peak demand. The average annual peak savings during the ISO-NE peak capacity hours based on energy storage dispatch profiles, according to the value of Avoided Pooled Transmission Facilities in Connecticut from the AESC and the value of avoided localized transmission and distribution from the C&LM Plan.

- Reliability
    - Changes in commercial, industrial, and consumer costs due to changes in the frequency and duration of outages. The average annual peak savings during the ISO-NE peak capacity hours based on energy storage dispatch profiles, according to the value of Reliability in Connecticut from the AESC.

- DRIPE Energy Impacts
    - Changes in the ISO-NE wholesale market clearing prices due to changes in energy purchases in the ISO-NE wholesale market, resulting from changes in energy consumption. The annual energy savings by ISO-NE costing period based on energy storage dispatch profiles, according to the value of intrastate and rest-of-pool demand reduction induced price effect (DRIPE) Energy in Connecticut from the AESC.

- DRIPE Capacity Impacts
    - Changes in the ISO-NE forward capacity market clearing prices due to changes in the levels of power contracted in the ISO-NE forward capacity market, resulting from changes in peak demand. The average annual peak savings during the ISO-NE peak capacity hours based on energy storage dispatch profiles, according to the value of intrastate and rest-of-pool Capacity DRIPE from the AESC.

- Cross-DRIPE Impacts
    - Changes in ISO-NE clearing prices due to changes in natural gas prices resulting from changes in energy consumption. The annual energy savings based on energy storage dispatch profiles, according to the value of DRIPE Energy in Connecticut from the AESC.[35]

[35] Cross-DRIPE primarily refers to the interconnected impacts, and associated costs and benefits, of the electric and gas systems. Since much of the electricity in ISO-NE is generated by natural gas power plants, a reduction in electricity demand reduces demand for natural gas, which reduces the price of natural gas and lowers the operating costs for natural gas power plants, further reducing the cost of electricity.

- Lost Utility Revenue (Participant Bill Savings)
  - Changes in utility revenue due to changes in energy consumption during higher cost periods. The annual energy savings by utility time of use (TOU) rate period based on energy storage dispatch profiles, according to the average TOU rates by utility and assuming annual rate growth of 2.61%.

- Upfront Incentives
  - The cost of upfront incentives provided to participants. The effective upfront incentive per participant applied to the number of participants.

- Performance Incentives
  - The cost of performance incentives provided to participants. The effective performance incentive per participant applied to the level of peak reduction for each participant.

- Upfront Incentive Program Costs (e.g., Administration)
  - The non-incentive cost associated with the upfront incentive. The fixed and variable components of the upfront incentive program costs.

- Performance Incentive Program Costs (e.g., Administration)
  - The non-incentive cost associated with the performance incentive. The fixed and variable components of the performance incentive program costs.

CGB RFPD Response, pp. 80-85

- Avoided Non-Embedded Emissions
  - The estimated emissions impacts based on ISO-NE electric-sector emissions rates by season, assuming a $100 per short ton of CO_2, net of emissions compliance costs already embedded in avoided energy costs.

Id, p. 90; CGB Response to CAE-8, p. 1

Each benefit-cost test identifies and quantifies the above cost and benefit categories associated with a different perspective, as described below:

- PACT – Analyzes the benefits and costs specific to the administrators of the Program, including all the costs and benefits from the upfront and performance incentives.
  - Benefits – Avoided Energy, Avoided Generation Capacity, Avoided Transmission & Distribution Capacity, Reliability, DRIPE Energy Impacts, DRIPE Capacity Impacts, Cross-DRIPE Impacts
  - Costs – Upfront Incentives, Performance Incentives, Program Administration

CGB RFPD Response, pp. 90-91

- PCT – Analyzes the benefits and costs specific to the electric customers that participate in the Program.
  - Benefits – Net Avoided Outage Benefits, Participant Bill Savings, Upfront Program Incentives, Performance Incentives, and Non-Program Incentives (Federal Tax Credit)
  - Costs – Upfront electric storage system costs, electric storage system lease value

CGB RFPD Response, p. 85

- SCT – Analyzes the benefits and costs from the combined perspective of the Program administrators and participants, plus the impacts on society.[36]
  - Benefits – Avoided Energy, Avoided Generation Capacity, Avoided Transmission & Distribution Capacity, Reliability, DRIPE Energy Impacts, DRIPE Capacity Impacts, Cross-DRIPE Impacts, Avoided Non-Embedded Emissions
  - Costs – Upfront Incentive Program Costs (e.g., Administration), Performance Incentive Program Costs (e.g., Administration)

CGB RFPD Response, p. 7

- TRC – Analyzes the benefits and costs from the combined perspective of the Program administrators and participants.[37]
  - Benefits – Avoided Energy, Avoided Generation Capacity, Avoided Transmission & Distribution Capacity, Reliability, DRIPE Energy Impacts, DRIPE Capacity Impacts, Cross-DRIPE Impacts
  - Costs – Upfront Incentive Program Costs (e.g., Administration), Performance Incentive Program Costs (e.g., Administration)

CGB RFPD Response, p. 7

- RIM – Analyzes the benefits and costs of the program that will impact electric ratepayers.
  - Benefits – Avoided Energy, Avoided Generation Capacity, Avoided Transmission & Distribution Capacity, Reliability, DRIPE Energy Impacts, DRIPE Capacity Impacts, Cross-DRIPE Impacts
  - Costs – Lost Utility Revenue, Upfront Incentives, Performance Incentives, Upfront Incentive Program Costs (e.g., Administration), Performance Incentive Program Costs (e.g., Administration)

CGB RFPD Response, p. 75

The CGB stated that a RIM greater than one indicates "ratepayers as a whole, including non-participant ratepayers, are not subject to a cost-shift, since the benefits outweigh the costs for ratepayers as a whole." CGB Written Comments, dated January 26, 2021, p. 17. Additionally, a PCT greater than one indicates "the benefits outweigh the

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[36] See, https://www.nationalenergyscreeningproject.org/wp-content/uploads/2020/08/NSPM-DERs_08-24-2020.pdf, Appendix E, p. 4

[37] See, https://www.nationalenergyscreeningproject.org/wp-content/uploads/2020/08/NSPM-DERs_08-24-2020.pdf, Appendix E, p. 3

costs for participants and could help indicate that the program would be attractive to participants." Id. Finally, a PACT greater than one indicates "the program benefits outweigh program costs and therefore that the incentives provided through the program will result in even greater benefits." Id. The CGB recommended considering all five tests for Program evaluation, and emphasized that the RIM is important to ensure that the Program is "delivering benefits to ratepayers without imposing costs on ratepayers." Id., Tr. 2/26/21, pp. 84-85.

The Authority appreciates the robust participation and detailed analysis provided by the CGB and its consultant to ensure the stated Program Objectives can be achieved. The Authority agrees with CGB that all five cost tests are appropriate to comprehensively analyze the Program's expected results in support of the Program Objectives. The Authority notes that the CGB's methodology is consistent with, and builds on, the Authority's approach across all programs authorized through its Equitable Modern Grid proceedings, which lean on the current cost-benefit methodologies, tests, and data inputs used in the C&LM Plan.

While the Authority agrees that all five cost tests should be considered to evaluate the cost-effectiveness of the Program, the RIM in particular was the subject of considerable discussion in his docket because, as the CGB notes, the RIM measures any potential cost shift to non-participants. As discussed above, programs such as the C&LM Plan do not typically use the RIM for program design, instead relying the PACT and TRC. However, PA 21-53 sets an objective for the Authority to "provid[e] positive net present value to all ratepayers, or a subset of ratepayers paying for the benefits that accrue to that subset of ratepayers," and to maximize the benefits to ratepayers derived from the wholesale capacity market, as discussed in Section III.A. As such, the Authority finds that the RIM is crucial in designing and evaluating the effectiveness of the Program authorized herein.

The Authority reiterates, however, that all five cost tests are vitally important and informative. Further, the Authority notes that not all Program benefits or Objectives can be captured through these tests, such as the added resilience for underserved communities and small businesses, or the local health benefits of replacing fossil fuel-based peaking generation and backup generators, among other examples. Regardless, due to the nascent nature and unique scope and breadth of this Program, it is important to set cost effectiveness targets so the Authority can be confident that the Program will deliver on the Objectives laid out in Section III.A. Therefore, the Authority directs the CGB to design upfront incentives, using the 2021 AESC, designed to deliver a RIM of 1.4 over the first three-year Program cycle.[38] As the electric storage devices are deployed and the costs and benefits of the Program are realized, the Authority may adjust this threshold to better reflect the reality of the overall Program costs and benefits and in order to meet the state's electric storage deployment targets.

[38] In calculating a RIM of 1.4, the CGB shall assume that all electric storage devices are standalone and that 50% participate in the FCM. As the CGB must submit the final incentive levels as a motion in Docket No. 21-08-05 no later than October 1, 2021, stakeholders will have at least the week following the submission of such motion to review and provide comment for the Authority's consideration.

As a baseline, the results of the CGB's most recent benefit-cost analyses are described below. See, CGB Brief, Attachment 1. The results include avoided costs calculated using the 2021 ASESC. The CGB shall update the BCAs shown below to reflect the final Program design as directed above, and incorporating all direction provided in this Decision. The CGB shall submit the final Program BCA in the first Annual Review proceeding no later than October 1, 2021. In addition, the CGB shall include an updated Program BCA in the annual report, as directed in Section V.F.

A. RESIDENTIAL PROGRAM-LEVEL BCA

For the residential portion of the Program, the CGB modeled the incentive structures described in Section III.C., inclusive of the upfront incentive shown in Table 2 and the ongoing summer performance incentive described in Table 4. Figures 1 through 3 below show all five benefit-cost tests for the residential portion of the Program:

Figure 1: Residential Program-Level BCA - 0% FCM Bid

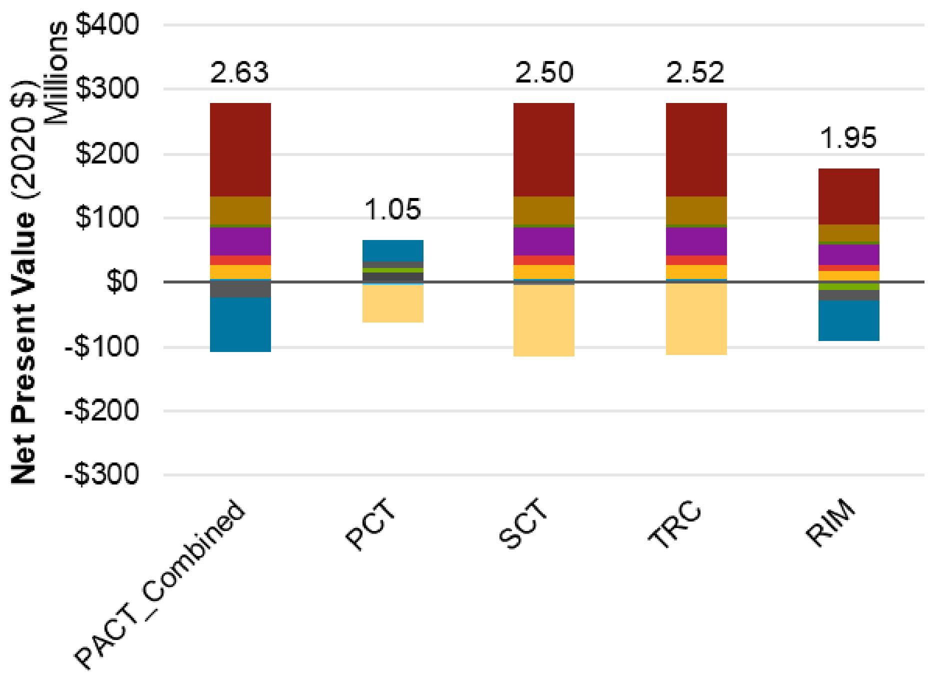


Figure 2: Residential Program-Level BCA - 50% FCM Bid

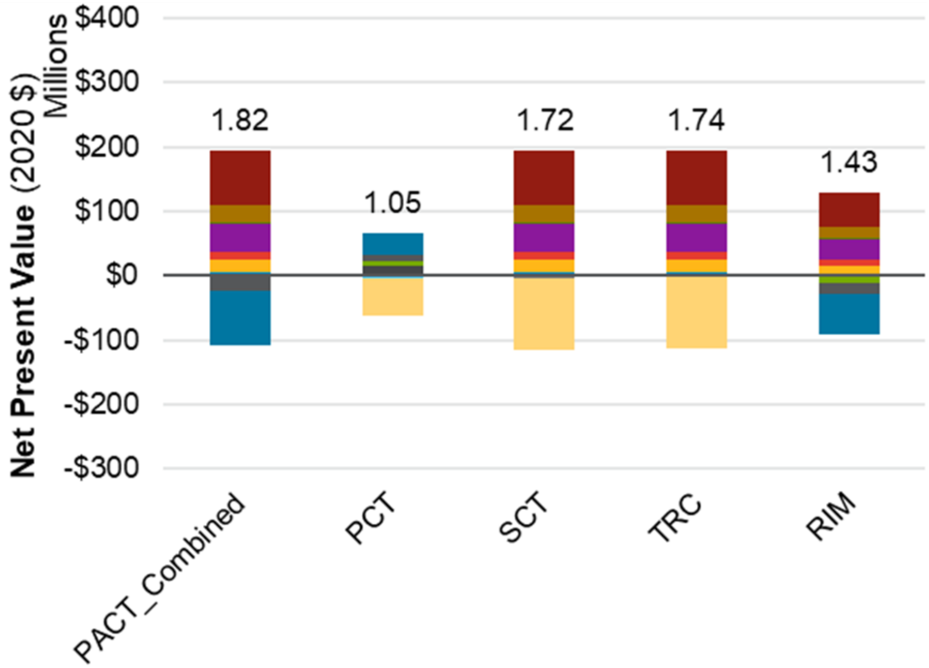
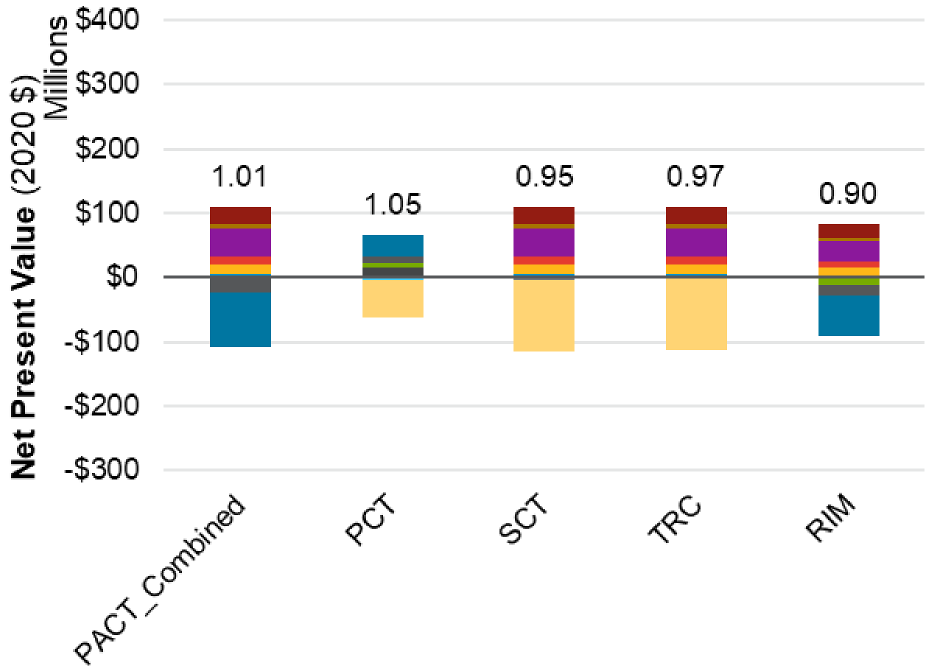


Figure 3: Residential Program-Level BCA - 100% FCM Bid



B. C&I PROGRAM-LEVEL BCA

For the C&I portion of the Program, the CGB modeled the incentive structures described in Section III.C., inclusive of the upfront incentive shown in Table 3 and the ongoing summer performance incentive described in Table 4. Figures 4 through 6 below show all five benefit-cost tests for the C&I portion of the Program:

Figure 4: C&I Program-Level BCA - 0% FCM Bid

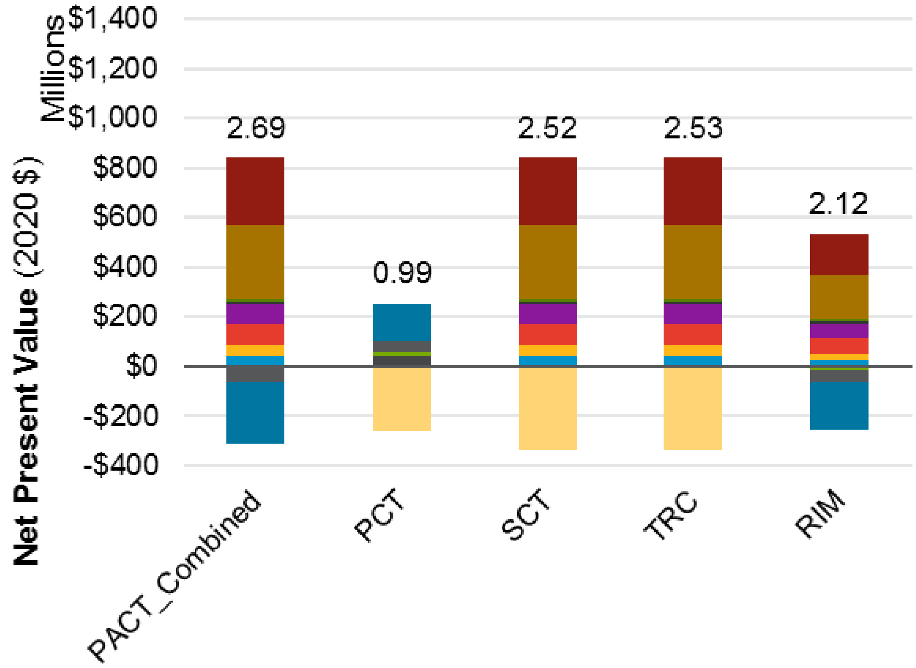


Figure 5: C&I Program-Level BCA - 50% FCM Bid

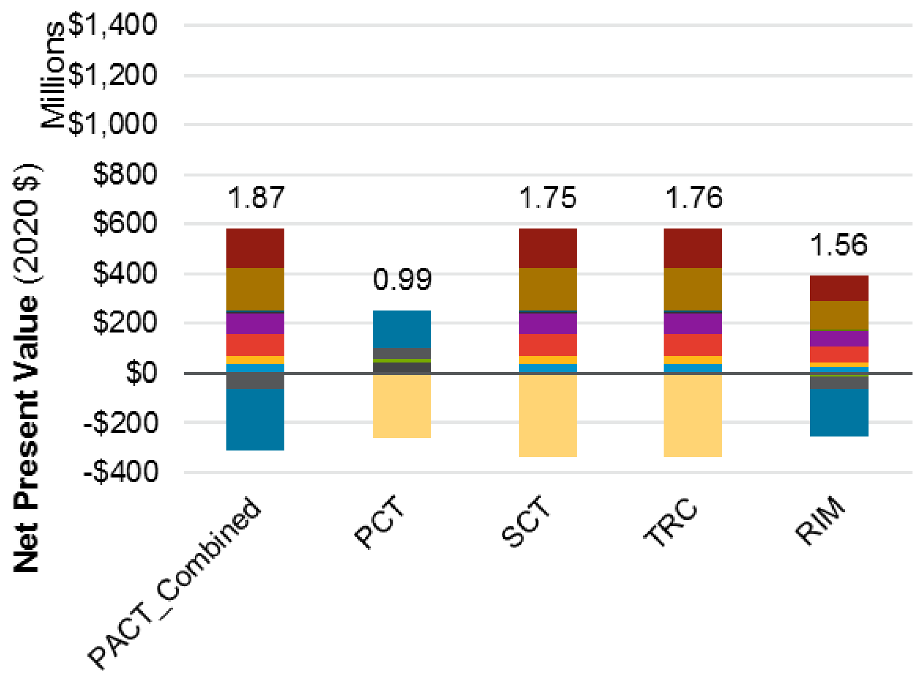
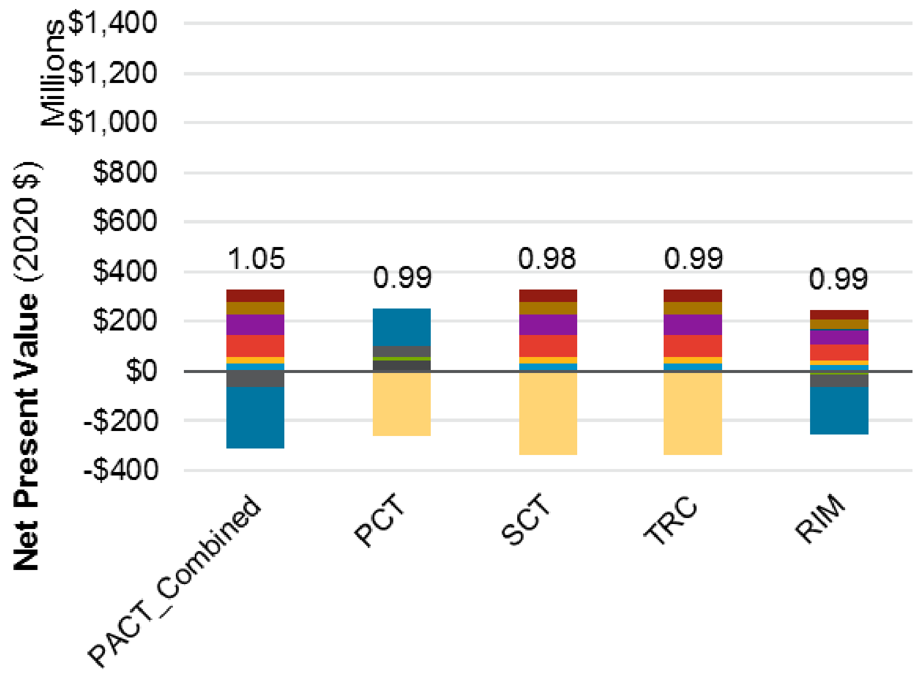


Figure 6: C&I Program-Level BCA - 100% FCM Bid



V. PROGRAM ADMINISTRATION

A. Program Administration Roles

UI proposed administration roles whereby the CGB would be responsible for financing, communication, and promotion through construction of the storage system with EDC input, while the EDCs would administer the performance incentives, determine inverter settings, and collect data with CGB input. UI Brief, p. 8. Eversource proposed the CGB administer aspects of the Program relating to marketing, financing, and data aggregation, while the EDCs retain operational control for active and passive dispatch including dispatch platform management, customer enrollment, performance incentive administration, and new technology evaluation and integration, Eversource Brief, pp. 10-12. The CGB stated it would work with the EDCs to “create processes that are as seamless as possible for all participants in all aspects of the Program, including customer, contractor and battery storage manufacturer engagement; project application review and approvals; integration of front and back-end systems (Power Clerk, Energy Hub, Virtual Peaker, etc.); completion and inspection requirements and associated processes; processes related to issuing incentive payments; and, data collection and EM&V.” CGB Written Comments, dated January 26, 2021, p. 12.

Based on the foregoing, the Authority establishes the following categories of Electric Storage Program administration; (1) customer enrollment; (2) marketing and outreach; (3) upfront incentive administration and passive dispatch settings; (4) performance incentive administration; (5) active dispatch; and (6) data aggregation and publication.

With respect to category (1) customer enrollment, the Program Administrators shall work together as directed in Section IV.B. to use a shared platform or integrated systems that collect(s) customer information. The CGB shall be responsible for categories (2) marketing and outreach, (3) upfront incentive administration and passive dispatch settings,[39] and (6) data aggregation and publication. The EDCs shall be responsible for categories (4) performance incentive administration and (5) active dispatch. Ultimately, the Program Administrators shall collaborate as necessary to ensure streamlined processes for each administration category.

Details regarding the six (6) program administration categories listed above are covered in throughout this Decision. Specifically, each is primarily addressed in the following sections:

- (1) customer enrollment – Section V.B.
- (2) marketing and outreach – Section V.C.
- (3) upfront incentive administration and passive dispatch settings – Sections III.C.1., III.C.2., III.D.1., and III.D.3.
- (4) performance incentive administration – Section III.C.3.
- (5) active dispatch – Sections III.D.2. and III.E.
- (6) data aggregation and publication – Sections V.D., V.E., and V.F.

Additional responsibilities not included in the six (6) identified buckets above are also discussed in this Section, including data privacy and security and electric storage system disposal. For any program administration roles that have not been assigned or require clarification, the Program Administrators shall jointly submit a written proposal regarding assignment of such roles for the Authority's review and approval as they are identified.

B. PARTICIPANT ENROLLMENT PROCESS

In order to create a seamless, single program experience, the CGB proposed requiring all customers to enroll through a single platform (e.g., PowerClerk) that collects all initial customer information. CGB Written Comments, dated January 26, 2021, p. 12. The platform would provide both the EDCs and CGB with information including basic customer information, passive and active dispatch enrollment status, and incentive levels, shared between the CGB and the EDCs. Id. Eversource also supported a single enrollment process to help lower barriers to adoption, and proposed the Company be responsible for customer enrollment. Eversource Brief, pp. 11-12. UI stated it would leverage its experience with demand response programs to ensure effective enrollment administration. UI Written Comments, dated January 26, 2021, p. 9.

The Authority agrees that a single enrollment platform will minimize customer confusion and help lower the barriers to entry for storage systems in Connecticut, in line with the Program Objectives. Accordingly, the Program Administrators shall work together to procure a single platform (e.g., PowerClerk or another least-cost option) or

[39] While the CGB is ultimately responsible for the passive dispatch settings, including determining the time period for dispatch and appropriate project auditing, the CGB shall consult the EDCs in establishing the passive dispatch settings, and the associated rule, and in recommending any subsequent changes.

integrated systems to collect all relevant enrollment information from customers. The enrollment platform or integrated systems shall result in a common customer experience between EDC service territories (i.e., same forms and general customer portal and/or interface) and in interacting with the Program Administrators (i.e., customers should not have to interact with the CGB and the EDCs separately, but instead should be able to use the same platform for interactions with either the CGB or the EDCs). No later than November 1, 2021, the Program Administrators shall submit for the Authority's review and approval the name and a description of the platform or other systems procured, including all capabilities and relevant cost information. Such filing shall also include details regarding the customer application process, including how and where customers may apply for the program starting January 1, 2022.

The CGB and the EDCs shall have shared access to all program data collected through the platform used to administer the program. After the customer is enrolled in both the upfront and performance portions of the Program, the following steps will occur:[40]

- Installation, municipal approval, interconnection approval, testing and commissioning, and project completion submission to enrollment platform (e.g., PowerClerk);
- Enrollment in dispatch platform;
- Project inspection;
- Begin participation in passive and active dispatch protocols; customers have 270 days from enrollment in both portions of the Program before the upfront incentive approval expires;
- Contractor or TPO reimbursed for upfront incentive already provided to customer as discount on sales/lease/PPA agreement;
- Performance measurement and reporting will be ongoing in accordance with the plan and schedule for EM&V;
- Performance-based incentive payments will be made on a schedule set up by the EDCs for an active demand response program; and
- Dispatch and performance monitoring continue for 10 years.

C. PROGRAM MARKETING

The CGB noted that it has "worked to foster the sustained orderly development of a local solar industry," and expects to similarly work with local partners such as residential solar contractors and storage providers to develop marketing campaigns based on its past experience with SolarizeCT, Solar for All, and EnergizeCT. CGB Written Comments, dated January 26, 2021, p. 13. The CGB accordingly proposed that the Authority direct it to develop a communication and promotion plan for the Program. Id., p. 10. The Authority appreciates the CGB's suggestion, and directs the Program Administrators to support a variety of outreach initiatives, specifically utilizing the following:

[40] Customers shall have 270 days from enrollment in both portions of the Program before the upfront incentive approval expires.

- SolarizeCT – refocusing community-based social marketing campaign to connect competitive market approaches (e.g., issuing RFP's for local contractors) to create demand for battery storage through a Storage campaign in collaboration with Yale;
- Solar for All – expanding its low-to-moderate income neighbor-to-neighbor message of residential solar PV to include third-party ownership of electric storage to provide access to affordable resiliency benefits;
- Sustainable CT – as an original co-founder and current co-chair of Sustainable CT, the CGB will promote the Program through local sustainability enthusiasts in Connecticut's cities and towns. Beyond marketing and outreach, the CGB will provide potential participants with the access to capital they may need to finance a system on their property – i.e., through loans, leases, and/or on-bill repayment mechanisms;
- EDC's respective websites;
- EnergizeCT; and,
- GoSolarCT.

Specifically, the CGB shall develop a communication and promotion plan (Marketing Plan) in collaboration with the EDCs, incorporating the above direction for the Authority's review and approval no later than October 1, 2021. All communications shall clearly convey that the CGB and the appropriate EDC are partnering to bring customers the Electric Storage Program overseen by PURA and paid for by ratepayers. Additionally, the CGB shall conduct a targeted communication and outreach campaign to recruit the customers defined in Sections III.C.1.a. and III.D.1. into the Program, namely low-income customers, customers in environmental justice communities and distressed municipalities, customers on the grid edge, critical facilities, facilities with existing fossil fuel generators, and small business customers. Such campaign may include providing additional on the ground and neighbor-to-neighbor research and marketing support to reduce the costs of customer acquisition by contractors, similar to its SolarizeCT campaign, and as suggested in its RFPD Response. See, CGB RFPD Response, pp. 17-18.

a. Stakeholder Resources

The Program Administrators shall update their respective websites to include a new webpage devoted to the Electric Storage Program that provides all relevant information for interested customers and electric storage contractors, and ensure that all information on such webpage remains up-to-date throughout the duration of the Program. The Program Administrators shall also develop, and update as necessary, resources for customers and electric storage contractors to easily participate in the Program. Such information shall include, but not be limited to: frequently asked questions; key program documents; and, all program forms and rules. The Program Administrators shall develop, and update as necessary, any other resources for customers and electric storage contractors to easily participate in the Program. The Program Administrators shall provide the Authority with a link to their respective webpages no later than December 1, 2021, and publish the webpages on or before January 1, 2022. The Authority also directs the CGB to function as a resource for energy storage contractor and developer questions. Additionally, the Program Administrators may request Technical Meetings, as necessary, in Docket No. 21-08-05 to inform successful communication with developers and ensure Program implementation by January 1, 2022.

D. DATA COLLECTION, SHARING, AND REPORTING REQUIREMENTS

The CGB noted its experience working with partners to integrate generation and grid performance data and its leadership in collecting and making program data publicly available. CGB RFPD Response, p. 57. Eversource asserted that allowing the Program Administrators to "play to their strengths" will result in the best program, and proposed CGB and the EDCs have joint responsibility for data collection and program performance calculations. Eversource Brief, pp. 10 and 12. The Authority agrees that both the EDCs and CGB have complementary capabilities, particularly regarding data collection, aggregation, and publication. Accordingly, the Authority directs the CGB, in concert with the EDCs, to develop an online portal that provides public access to, anonymized Program information at the most granular level possible, including, but not limited to:

- Aggregate storage dispatch, at the most granular level possible;[41]
- Historical aggregate hourly dispatch;
- Six-month rolling average installed cost data;
- Historical installed cost and TPO customer agreement data, by contractor, system locations, and application date;
- Program incentive funds disbursed;
- Program administrative costs;
- Installed capacity (number of units, kW, and kWh), in aggregate and by town;
- Installed capacity (number of units, kW, and kWh) in low-income households and underserved communities;
- Aggregate avoided emissions (CO_2, NO_X, SO_X); and
  - Average project metrics, such as: Incentive per unit,
  - Electric storage system size (kW),
  - Electric storage system size (kWh).

Ultimately, the Authority directs the Program Administrators, in consultation with DEEP as necessary, to develop a landing page for all data relevant to the Program to provide interested stakeholders with the most up-to-date information possible, in an easily understood and digestible form. The Program Administrators shall publish this data to their Program website or a new, distinct website on or before January 1, 2023.[42]

Further, as proposed by DEEP in its Written Exceptions, the Program Administrators shall provide an analysis of current deployment (e.g., map overlaying deployments with underserved communities, historically, marginalized communities, or other similar metric(s)) and propose additional methods to collect and report data regarding the residential upfront incentive adder for low-income customers and underserved communities, including metrics related to household race or ethnicity, no later than June 1, 2022. DEEP Written Exceptions, pp. 2-4.

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[41] Ideally, data would both be provided in 15-minute intervals in aggregate form, as well as in "real-time". For an example of the presentation of real-time data, see, https://www.iso-ne.com/isoexpress/web/charts.

[42] The Authority directed that similar webpages be developed for the Residential Tariffs and Non-Residential Tariffs Programs authorized in Docket No. 20-07-01. The Authority encourages the Program Administrators to develop one landing page for all data relevant to those programs and the Program authorized herein.

Finally, the Authority previously determined in its Interim Decision dated February 10, 2021 in Docket No. 20-07-01 that all residential solar PV production data should be made available to PURA, DEEP, the OCC, and the participating residential end-use customers (including TPOs) on a real-time and downloadable basis, since ratepayers are supporting the cost-recoverable investments.[43] The Authority finds a similar approach appropriate for the Electric Storage Program, and directs the Program Administrators to work together to include data release clauses in the appropriate Program documents. Finally, the Program Administrators shall provide DEEP, the OCC and the Authority with access to the performance data (e.g., battery output, ratio of dispatch responses to calls, etc.) of participating systems no later than January 1, 2023.

E. PURA Program Review Process

The CGB supported an annual 90-day review process and a 120-day full program review process, and stated such reviews would "continuously improve the overall delivery of the Program." CGB Written Comments, dated January 26, 2021, pp. 14-15. OCC additionally supported three-year deployment increments to allow for regular review of costs and benefits and to re-assess program targets. OCC Written Comments, dated January 26, 2021, p. 10. UI agreed with a three-year program review cycle, while Eversource similarly asserted that robust three-year reviews that examine incentive levels, program costs, and benefits will ensure the Program delivers the maximum value. UI Written Comments, dated January 26, 2021, p. 7; Eversource Written Comments, dated January 26, 2021, pp. 6-7.

Accordingly, the Authority establishes a nine-year Program to support electric storage in Connecticut, starting on January 1, 2022, and continuing through at least December 31, 2030. The Program is structured around three-year cycles (Program Cycles) whereby the Authority will evaluate whether the Program is delivering on the expected value to ratepayers and is meeting the stated Program Objectives. During the first two years of every Program Cycle (e.g., 2022 and 2023), the Authority will conduct an annual review process (Annual Review) beginning on or around August 1 of each year to review key metrics and to make strategic adjustments, as provided by the Program Administrators and/or the EM&V firm, and to make small, strategic adjustments, as necessary, to ensure: (1) continued alignment with the Program Objectives; and (2) that the Program is on track to meet its three-year program cycle deployment targets.[44]

Key Annual Review filings shall be submitted on or around August 1st by the appropriate Program Administrator as directed in this Decision, including, but not limited to: an annual report, including Program results and recommendations for Program modifications as discussed in Section V.F.; a list of the energy storage systems and inverter technologies that can and cannot currently interface with each EDC's dispatch platform(s), including a summary of the EDC's efforts to ensure that all energy storage systems and inverter technologies can effectively interface with its dispatch platform(s) as directed in Section III.F. The Authority will endeavor to conclude the Annual Review within 90 days to provide the Program Administrators and the market time to implement and react to any changes for the next program year.

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[43] See, Interim Decision, dated February 10, 2021, Docket No. 20-07-01, pp. 32-33.

[44] The Authority anticipates designating this proceeding Docket No. XX-08-05 (e.g., 21-08-05, 22-08-05, etc.).

During the last year of each three-year Program Cycle (e.g., 2024), the Authority will conduct a full program review (Program Review) beginning on or around June 15, 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. The Authority will also revisit electric storage deployment targets, the breakdown of deployment targets by customer class, and incentive structures considering the current status of energy storage in Connecticut. The Authority will hold at least one public meeting during the course of the Program Review. The Authority will endeavor to conclude the Program Review within 120 days.

1. 2021 and 2022 Annual Reviews

The Authority anticipates initiating a proceeding in August 2021 (i.e., Docket No. 21-08-05) to review the Program Design Documents developed by the Program Administrators pursuant to the direction provided throughout this Decision, along with other key compliance ordered herein including the final incentive levels calculated by the Program Administrators. The Program Administrators are directed herein to submit various key filings in Docket No. 21-08-05 no later than October 1, 2021 in order to provide the Authority sufficient time to review and allow for meaningful stakeholder input prior to Program launch on January 1, 2022.

Additionally, as the Authority directs the Program Administrators herein to propose certain program design elements after the Program launches, the 2022 Annual Review (i.e., Docket No. 22-08-05) will consist of a more substantive review process. Specifically, as directed in Section III., the following proposals are required to be submitted by the Program Administrators for consideration for Year 2 of the Program (starting January 1, 2023):

- A proposal to increase the emission reduction benefits associated with the Program; and
- Proposals for FTM electric storage system incentives.

The Authority may also further consider the costs and ratepayer impacts of the EDCs' DRMS and DERMS, as discussed in Section III.D. Additionally, the Authority continues to endeavor to identify areas where its Equitable Modern Grid initiatives may complement one another. In the Decision concerning electric vehicles (EVs) in Docket No. 17-12-03RE04, PURA Investigation into Distribution System Planning of the Electric Distribution Companies –Zero Emission Vehicles (EV Decision), the Authority directed the EDCs to finalize managed charging programs for residential single-family EV drivers and light-duty EV fleet customers.[45] The Authority anticipates such managed charging programs to be launched on January 1, 2022. To further support the Program Objective to provide multiple types of benefits to the electric grid, the Authority directs the CGB, in collaboration with the EDCs as appropriate, to propose Program modifications that will enable the Electric Storage Program authorized herein to better complement or otherwise support the managed charging programs authorized by the Authority in the EV Decision.

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[45] See, EV Decision, p. 15. http://www.dpuc.state.ct.us/dockcurr.nsf/8e6fc37a54110e3e852576190052b64d/66732b0f065302c1852586ef0075ca47/$FILE/17-12-03RE04%20PFD.pdf

Such proposal shall be submitted no later than August 1, 2022 for consideration in the 2022 Annual Review (i.e., Docket No. 22-08-05) for potential adoption in Year 2 (2023). The Authority will monitor any technological advancements concerning EVs and electric storage and may consider Program modifications as appropriate in the relevant Annual or Program Review.

F. Evaluation, Measurement, and Verification (EM&V)

The CGB supported using a competitively sourced third-party for Program EM&V, noting that the CGB regularly qualifies such vendors every three years. CGB Written Comments, dated January 26, 2021, p. 15. The OCC similarly supported the use of a single third-party consultant for EM&V. OCC Written Comments, dated January 26, 2021, p. 16. Eversource proposed the EDCs and the CGB jointly manage any potential third-party EM&V. Eversource Brief, p. 12. UI stated that it would be reasonable to develop a process for retaining a third-party EM&V consultant to conduct EM&V, and expressed its intent to create EM&V metrics that ensure storage systems are ready and available to participate in the dispatch programs. UI Written Comments, dated January 26, 2021, pp. 10-11.

To determine Program success, DER Task Force suggested evaluating how systems are being used, the differences in use based on ownership, carbon emissions impact of storage, and changes in energy market prices. DER Task Force RFPD Response, p. 6. NECEC and ESA jointly recommended determining the performance ratio of projects (e.g., how many responses to calls), reduced peak demand and any avoided transmission and distribution costs, and retrospective emissions impacts. NECEC/ESA RFPD Response, p. 4. Eversource proposed metrics for total installed power and energy capacity, number of residential, LMI, and C&I units installed, peak system reduction (kW), energy reduction associated with various use cases, and avoided energy and demand costs as determined through a BCA model. Eversource RFPD Response, pp. 28-29. UI proposed similar metrics, also suggesting metrics associated with dispatch events including amount of kW called per event, units not responding per month, and aggregated revenue per month. UI RFPD Response, p. 16. The OCC recommended tracking Program benefits and costs through EM&V to inform each Program Review. OCC Written Comments, dated January 26, 2021, p. 16.

The Authority accordingly directs the Program Administrators to retain a third party to evaluate, measure, and verify results of the Program (EM&V Consultant). The EM&V Consultant shall develop Program metrics, associated calculation methodologies, and data requirements for verifying Program performance based on the established metrics. All metrics and calculation methodologies shall be subject to review and approval by the Authority, and the Authority may request additional input on metrics through a public input process. The Program metrics shall include, but not be limited to:

- The actual, realized benefit-cost ratios for all five cost tests listed in Section IV.;
- Program incentive funds disbursed ($);
- Program administrative costs ($);
- Installed system cost ($/kW and $ $/kWh);

- Installed capacity (number of units, kW, and kWh);
- Number of residential, LMI and underserved community, and C&I units installed;
- Percentage of total residential deployment receiving the upfront incentive adder for low-income customers and underserved communities;
- Percentage of residential deployment in underserved communities;
- Percentage of residential deployment to customers enrolled in a utility hardship program;[46]
- Amount of kW per called event;
- Peak demand savings (kW) based on ISO-NE definition for both active and passive demand response;
- Fraction of usable solar energy used for back-up power, as well as passive and active demand response by location, anonymized and aggregated for public reporting;
- Number of back-up power incidents and peak dispatch events, and battery availability for the incident and events by location, anonymized and aggregated for public reporting;
- Aggregate avoided emissions (CO_2, NO_X, SO_X);
- Emissions data (CO_2, NO_x SO_x) at the most granular level practicable[47]; and
- Average project metrics, such as:
  - Incentive per unit,
  - Electric storage system size (kW),
  - Electric storage system size (kWh).

The cost of the EM&V Consultant shall not exceed five percent of the total Program costs for any three-year program cycle. The Authority directs the Program Administrators to submit a proposed RFP to retain a third-party EM&V Consultant for the first three-year program period for Authority no later than August 15, 2021.[48] At minimum, the proposed RFP scope of work shall specifically identify and describe within the metrics outlined above, expectations for meeting the annual reporting requirements, and the following additional time-sensitive work. The Program Administrators, in coordination with the EM&V Consultant, shall develop and submit for the Authority's review, modification, and approval Program metrics, associated calculation methodologies, and data requirements for verifying Program performance based on the established metrics. The proposed Program metrics, calculation methodologies, and, data requirements shall be submitted for the Authority's review and approval on or before December 15, 2021.[49]

[46] Ideally, the Program metrics would also include the following: percentage of residential deployments by household race or ethnicity; and percentage of residential deployments by income bracket. The Authority understands that tracking such information may not be immediately achievable; however, the Program Administrators shall consider incorporating such metrics in the future.

[47] The Program Administrators shall use the resources on page six (6) of Policy Integrity/WattTime's Written Comments dated January 26, 2021 to fullest extent possible to inform this analysis.

[48] The Program Administrators shall notify the Authority, through the relevant docket, of the retention of and contact information for the EM&V Consultant.

[49] The Program Administrators shall submit, at a minimum, a list of initial data to be collected and metrics to be tracked for Program Year 1 (2022) by December 15, 2021. A more complete filing may be made subsequently; however, the Program Administrators will not be compliant with the Order No. 16 until all relevant information is provided by the EM&V Consultant.

1. Reporting Requirements

The Program Administrators shall provide an annual report summarizing the Program results to date and recommendations for any Program modifications no later than August 1 through the relevant annual review proceeding. The Authority will review the Program Administrators' annual report through the Annual Review or Program Review processes, depending on the year. At a minimum, such annual report shall detail the savings delivered and progress on the Authority-approved Program metrics, including an updated BCA. The Authority encourages additional reporting through the relevant Authority proceeding, specifically the additional reporting proposed by the CGB in its RFPD Response. The Program Administrators shall strive to provide such reporting in accordance with the annual processes and other data sharing requirements detailed herein, specifically Sections V.A through V.F.

The EM&V Consultant shall submit a full report on the established Program metrics into the relevant docket on or around June 15 of the last year of each three-year program cycle (e.g., on or around June 15, 2024). The Authority will review the EM&V Consultant's report through the Program Review process.

G. DATA PRIVACY AND SECURITY PLAN

Eversource, UI, and the CGB each proposed data privacy and cybersecurity plans. The CGB proposed to use three platforms to maintain data privacy and security; PowerClerk, LocusNOC, and Virtual Peaker's DRMS. CGB RFPD Response, p. 93. The CGB stated that PowerClerk is a robust program management platform already used for multiple state energy incentive programs, including by Eversource for interconnection applications. Id. Additionally, the CGB noted that cybersecurity for energy storage systems relies on the security of the technology provider's software platform. Id. pp. 93-94. The CGB stated an annual external audit is performed on all of its technology systems and processes, which includes verification of compliance with standards for security, availability, processing integrity, confidentiality, and privacy. Id., p. 94. Finally, the CGB noted that data ownership, custodianship, and roles and responsibilities would be managed through its software platforms, with data access determined by user role. Id.

Eversource provided a Grid Modernization Cyber Security Plan, which summarized the Company's overall cybersecurity program as it relates to grid modernization technologies. Eversource RFPD Response, Attachment A, p. 5. In the plan, Eversource stated it follows National Institute of Standards and Technology (NIST) guidelines for cybersecurity along with the DataGuard Energy Data Privacy Program developed by the United States Department of Energy. Id. Further, Eversource asserted that its standards "ensure that security measures and risk management efforts align appropriately with priority of Grid Modernization processes and technologies for which Eversource is responsible." Id. Additionally, Eversource stated its data privacy measures include physical and access controls, encryption, monitoring, training, and third-party security reviews, among others. Id., p. 10.

UI stated its parent company, Avangrid, has cybersecurity processes and procedures in place that UI would follow. UI RFPD Response, p. 19. UI stated such processes and procedures "draw[s] from industry standards and best practices to protect the confidentiality, integrity, availability, and reliability of UI's cyber infrastructure." Id. Further, UI noted it assesses third parties for information security, such as operational, technical, and administrative controls. Id. UI also stated its processes integrate industry best practices, including several NIST Cybersecurity Framework publications. Id. Finally, UI stated it follows industry standard data aggregation methods to protect the identity of individual customers. Id., p. 20.

The Authority appreciates the thought given to the Program Administrators' data privacy and cybersecurity proposals described above. For statewide consistency, the Program Administrators shall jointly develop one comprehensive Data Privacy and Security Plan for the Program, to be submitted for Authority review and approval on or before December 15, 2021. Such Plan shall build on the Program Administrators' proposals, and specifically: align with industry standards, best practices, and any state or federal regulations designed to protect customer data and prevent cybersecurity attacks; include data aggregation standards and the ability and methods to pseudo-anonymize or anonymize data, when applicable; address data ownership, data custodianship, and their roles and responsibilities and include data flows and system touch points that identify data ownership (customer/EDC), data custodianship, and aggregated or anonymized data ownership; and include provisions for access to the data by the Authority and other government agencies, as directed in Section IV.D. Additionally, the Program Administrators shall include in its Data Privacy and Security Plan filing, a separate list of data sharing and security requirements for any electric storage device participating in the Program, specifically highlighting the information that will be provided to customers and any data sharing agreements.

Last, the Data Privacy and Security Plan submitted in compliance with this Decision shall be revised and resubmitted for the Authority's review and approval within 30 days of the submission of any similar plans filed in Docket No. 17-12-03RE02, PURA Investigation into Distribution System Planning of the Electric Distribution Companies - Advanced Metering Infrastructure, highlighting the areas specific to the Program not covered in the plans ordered in Docket No. 17-12-03RE02.

H. SYSTEM DISPOSAL

The Program Administrators shall require that the decommissioning of any electric storage system participating in the Program be completed by the operations and maintenance provider of the system, or by the original engineering, procurement, and construction (EPC) contractor. The Program Administrators shall include any language formalizing such a requirement in the Program Design Documents. The Authority reserves the right to further address the decommissioning process for participating systems in a future Annual or Program Review.

VI. COST RECOVERY

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 shall submit its costs into both dockets splitting its costs between Eversource and UI based on the proportion of megawatts deployed in each EDC's respective service territory, as suggested by the OCC. OCC Written Comments, dated January 26, 2021, p. 16. The EDCs shall each pay the CGB its annual costs authorized by the Authority associated with the administration of this Program in monthly installments starting the first month electric rates reflect the recovery of such costs from ratepayers.[50] All costs shall be charged to the Non-bypassable Federally Mandated Congestion Charge (NBFMCC). As the actual collections from customers will fluctuate, any over- or under-collection from the forecasted CGB costs will be addressed in the following year's RAM proceeding, incorporating the appropriate accrual of carrying charges.

For program administration costs expected to be incurred during the launch and initial year of the Program, each Program Administrator may request some portion of their anticipated costs to be included in rates set May 1, 2022 through Docket Nos. 22-01-03 and 22-01-04, so long as such request is submitted by January 15, 2022 in both dockets and is accompanied by a line item estimate of all costs requested to be incorporated into rates. Additional incremental 2022 program costs not included in the January 15, 2022 filings will be addressed through the 2023 RAM proceeding.

In addition, the EDCs may develop and submit for the Authority's review, modification, and approval a proposal for incentivizing the EDCs to optimize the active dispatch of all electric storage systems participating in the Program under the EDCs' operational control. Such proposal, including any necessary additions or modifications to the program rules and associated documents, must be submitted for the Authority's review, modification, and approval on or before August 1, 2022.

Finally, the CGB proposed to recover its Program costs based on installed systems' performance through the following milestones:

- Year 1 – ensuring that the systems installed are up-and-running as a complete unit as determined by a Green Bank inspector and confirmed to be "online" and "visible" with the DRMS partner;
- Year 2 – default settings for passive dispatch (i.e., ISO-NE summer peak periods) are in reasonable remote operation and "controllable" with the DRMS, and that data management, collection, and analysis is in process for EM&V purposes; and
- Year 3 – the systems within the portfolio of projects supported by the Program are within 20% of the overall PACT for the capacity block within the upfront declining incentive structure. To ensure that we are maximizing ratepayer benefits, consideration should be given to also verifying an acceptable RIM test.

CGB Written Comments, dated January 26, 2021, pp. 15-16

[50] Such payments shall be based on the approved amount collected from ratepayers through the NBFMCC for such purposes.

The Authority appreciates the CGB's proposal. The CGB may develop and submit for the Authority's review, modification, and approval a final proposal for performance-based recovery of Program costs, incorporating its proposal outlined above. The CGB may also develop and submit for the Authority's review, modification, and approval a proposal for performance-based cost recovery of its administrative costs associated with its duties as a Program Administrator. Such proposal must demonstrate that any cost recovery beyond the CGB's prudently-incurred administrative costs are in-line with or below the margin that could reasonably be expected to be incurred by a third party program administrator, should one have been retained to administer the same portions of the Program. Such proposal, including any necessary additions or modifications to the program rules and associated documents, must be submitted for the Authority's review, modification, and approval on or before August 1, 2022.

VII. CONCLUSIONS AND ORDERS

A. CONCLUSION

In this Decision, the Authority establishes a nine-year statewide Electric Storage Program in order to leverage the value of electric storage for the net benefit of the electric distribution system. The Decision combines program areas for residential, commercial, and industrial customers, as well as systems connected in front of the meter and not at a customer's own premise. The Program includes a declining-block upfront incentive for residential customers and a single upfront incentive block for commercial and industrial customers, along with a performance-based incentive structure for all participating projects, available to all customers of the state's EDCs. The Program has a deployment target of 580 MW by 2030.

The CGB and the EDCs will jointly administer the Program; the CGB will administer the upfront incentive portion of the Program and will be responsible for Program communication and promotion, while the EDCs will administer the performance incentive and the active dispatch portions of the Program. The Program Administrators (CGB and the EDCs) will develop the appropriate program documents necessary to effectively implement the Program beginning January 1, 2022. The Authority will re-evaluate whether the Program is delivering the expected ratepayer benefits and meeting the overall objectives of the Program during three-year review cycles.

B. 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.

1. No later than August 15, 2021, the Program Administrators shall submit for the Authority's review and approval a proposed RFP to retain a third-party EM&V Consultant for the first three-year program period in Docket No. 21-08-05.

2. No later than October 1, 2021, the Program Administrators (i.e., Eversource, UI, and the CGB) shall jointly develop and file the final Program Design Documents, incorporating all direction provided herein, for the Authority's review and approval in Docket No. 21-08-05. Such final Program Design Documents must also be accompanied by the resources discussed in Section V.C.a. (e.g., frequently asked questions) and incorporate any relevant information from Order Nos. 3 through 26.

3. No later than October 1, 2021, the Program Administrators shall also develop and file for the Authority's review and approval rules guiding the distribution of the upfront incentive payment to participating electric storage system owners in Docket No. 21-08-05 consistent with the direction provided in Section III.C.

4. No later than October 1, 2021, the Program Administrators shall also jointly develop and file for the Authority's review and approval rules guiding the distribution of the summer and winter performance incentive payments to participating electric storage system owners in Docket No. 21-08-05 consistent with the direction provided in Section III.C. Such rules shall also include the active dispatch guidelines, including the customer enrollment process and incorporating all direction provided in Sections III.C, III.D, and III.F. in Docket No. 21-08-05.

5. No later than October 1, 2021, the CGB shall file for the Authority's review and approval the final upfront incentive levels and corresponding formula(s) for deriving the actual incentive for each participating device in Docket No. 21-08-05 consistent with the direction provided in Section III.C.

6. No later than October 1, 2021, the CGB shall submit for the Authority's review and approval a proposed upfront incentive adder and a proposed methodology to verify eligibility for qualifying low-income customers and customers in underserved communities in Docket No. 21-08-05.

7. No later than October 1, 2021, the CGB shall submit a final Program BCA, reflecting the final Program design and incorporating all direction provided in this Decision in Docket No. 21-08-05.

8. No later than October 1, 2021, and by August 1st annually thereafter, the EDCs shall submit for the Authority's review and approval 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.

9. No later than October 1, 2021, the CGB shall submit a communication and promotion plan (Marketing Plan) for the Authority's review and approval, incorporating all direction provided herein in Docket No. 21-08-05.

10. No later than October 1, 2021, the CGB shall submit for the Authority's review and approval an ISO-NE market participation verification process, incorporating all direction in Section III.D.3., in Docket No. 21-08-05.

11. No later than October 1, 2021, the EDCs shall propose a revenue-neutral tariff for FTM electric storage systems to be made effective on or before January 1, 2022, and incorporating all direction provided in Section III.C., in the appropriate Annual Review proceeding.

12. 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, as applicable.

13. No later than November 1, 2021, the Program Administrators shall submit for the Authority's review and approval the name and a description of the customer enrollment platform or other systems procured, including all capabilities and relevant cost information, and details regarding the customer application process, in Docket No. 21-08-05.

14. No later than December 1, 2021, the EDCs shall file with the Authority a link to their respective Program webpages, which shall incorporate all direction provided herein. Such webpages shall be made public no later than January 1, 2022.

15. No later than December 15, 2021, the Program Administrators shall submit a Resiliency Plan template and proposed application process for the Authority's review and approval in Docket No. 21-08-05, incorporating all direction in Section III.D.1.

16. No later than December 15, 2021, the Program Administrators, in coordination with the EM&V Consultant, shall develop and submit for the Authority's review, modification, and approval Program metrics, associated calculation methodologies, and data requirements for verifying Program performance based on the established metrics in Docket No. 21-08-05.

17. No later than December 15, 2021, the Program Administrators shall jointly submit one comprehensive Data Privacy and Security Plan for the Program for the Authority's review and approval in Docket No. 21-08-05.

18. No later than January 1, 2022, the EDCs shall submit for Authority review a comprehensive description of their respective existing DRMS and DERMS platforms, including but not limited to a description of the procurement process and timeline, upfront and ongoing system costs, and a description of how the costs for such systems are paid for by ratepayers, as directed in Section III.F.

19. No later than June 1, 2022, the CGB shall submit a filing that proposes program modifications based on the results of its conversations with FTM electric storage stakeholders, DEEP, the EDCs, and wholesale market participants, including relevant BCAs specific to FTM electric storage systems, in the appropriate annual Program review proceeding.

20. No later than August 1, 2022, the CGB shall submit for the Authority's review a proposal to better optimize the emissions reductions achievable through the Program, incorporating all direction provided in Section III.D.3., in the appropriate annual Program review docket.

21. No later than August 1, 2022, the Program Administrators shall submit a proposal for Program modifications that will enable the Program to better complement or otherwise support the managed charging programs contemplated by the Authority in the EV Decision in the appropriate annual Program review proceeding.

22. No later than August 1, 2022, and annually thereafter, the Program Administrators shall submit an annual report summarizing the Program results to date, including an updated BCA, and recommendations for any Program modifications in the relevant Annual Review proceeding.

23. No later than January 1, 2023, the Program Administrators shall provide the OCC, DEEP, and the Authority with means to access the performance data (e.g., battery output, ratio of dispatch responses to calls, etc.) of participating energy storage systems on a downloadable basis.

24. 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.

25. No later than June 15, 2024, and every three years thereafter, the Program Administrators shall submit the EM&V consultant's full report on the established Program metrics into the relevant Program Review proceeding.

26. The CGB shall provide notice to the Authority as a compliance filing and in the applicable docket(s) when a given capacity block is near completion. Specifically, the CGB shall: (1) set a date for the start of the subsequent step (e.g., first day of the next month), and (2) notify the market and the Authority that current step will end on a specific date (e.g., last day of the current month) and that the subsequent step will begin the day after (e.g., first day of the next month).

DOCKET NO. 17-12-03RE03 PURA INVESTIGATION INTO DISTRIBUTION SYSTEM PLANNING OF THE ELECTRIC DISTRIBUTION COMPANIES – ELECTRIC STORAGE

This Decision is adopted by the following Commissioners:

Marissa P. Gillett

John W. Betkoski, III

Michael A. Caron

CERTIFICATE OF SERVICE

The foregoing is a true and correct copy of the Decision issued by the Public Utilities Regulatory Authority, State of Connecticut, and was forwarded by Certified Mail to all parties of record in this proceeding on the date indicated.

Jeffrey R. Gaudiosi, Esq. Executive Secretary Public Utilities Regulatory Authority	July 28, 2021 Date

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