STATE OF CONNECTICUT

PUBLIC UTILITIES REGULATORY AUTHORITY
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DOCKET NO. 26-08-02 **ANNUAL RESIDENTIAL RENEWABLE ENERGY SOLUTIONS PROGRAM REVIEW AND RATE SETTING – YEAR 6**

October 28, 2026

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DECISION

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DECISION

I. INTRODUCTION

A. SUMMARY

In this Decision, the Public Utilities Regulatory Authority (Authority or PURA) approves updates to the Residential Renewable Energy Solutions Program (RRES Program or Program), administered by The Connecticut Light and Power Company d/b/a Eversource Energy (Eversource) and The United Illuminating Company (UI; collectively, with Eversource, the electric distribution companies or EDCs). The approved changes are intended to better align the RRES Program with the program objectives. The Decision also sets the RRES Program Tariff rates for project applications received in calendar year 2027.

B. BACKGROUND OF THE PROCEEDING

On February 10, 2021, the Authority issued an Interim Decision in Docket No. 20-07-01, PURA Implementation of Section 3 of Public Act 19-35, Renewable Energy Tariffs and Procurement Plans (Residential Tariff Decision), establishing renewable energy tariffs for residential customers of each EDC effective January 1, 2022, through December 31, 2027, pursuant to General Statutes § 16-244z subsections (b), (d), (e), and portions of subsection (c). In the Residential Tariff Decision, the Authority established five objectives to guide the development, implementation, and administration of the RRES Program (Program Objectives).

The approved tariff program was subsequently named the RRES Program. The Authority initiates a docket annually to review key RRES Program metrics, including deployed megawatts (MW) and low- and moderate-income customer participation, and to ensure the Program is "on track to at least maintain historical deployment levels and to deliver a carbon free grid by 2040." Residential Tariff Decision, p. 40.

The Authority utilizes the annual proceeding to "set the [RRES Program] Tariff rates, any separate [renewable energy certificate (REC)] payments, and any fully, non-bypassable charges for Program applications received during the following calendar year." Id. The Authority also uses the docket to evaluate the key data inputs, in addition to MW deployed, necessary to establish the annual RRES Program Tariff rates. Id.

The Authority conducted the first annual RRES Program review in Docket No. 21-08-02, Annual Residential Renewable Energy Tariff Program Review and Rate Setting, issuing decisions on October 6, 2021 (Year 1 Decision), January 5, 2022, and June 8, 2022. The decisions respectively finalized the manual (Program Manual) and set the RRES Program tariff rates for project applications received in calendar year 2022, provided limited modification and clarifications of the RRES Program Manual, and established eligibility and participation guidance for affordable housing in the RRES Program.

The Authority conducted the second annual RRES Program review in Docket No. 22-08-02, Annual Residential Renewable Energy Solutions Program Review – Year 2, issuing decisions on November 2, 2022 (Year 2 Decision), and February 8, 2023. The decisions finalized the Year 2 Program Manual, established RRES Program tariff rates for project applications received in calendar year 2023, and authorized several changes to the application process to better align the Program with the Program Objectives.

The Authority conducted the third annual RRES Program review in Docket No. 23-08-02, Annual Residential Renewable Energy Solutions Program Review – Year 3, issuing decisions on November 1, 2023 (Year 3 Decision), and July 10, 2024. The decisions finalized the Year 3 Program Manual, established RRES Program tariff rates for project applications received in calendar year 2024, authorized several changes to the Program to better align with the Program Objectives, and established eligibility and participation guidance for master-metered affordable housing in the RRES Program.

The Authority conducted the fourth annual RRES Program review in Docket No. 24-08-02, Annual Residential Renewable Energy Solutions Program Review – Year 4, issuing a decision on October 16, 2024 (Year 4 Decision). The decision set the RRES Program tariff rates for project applications received in calendar year 2025 and authorized changes to metering and wiring requirements.

The Authority conducted the fifth annual RRES Program review in Docket No. 25-08-02, Annual Residential Renewable Energy Solutions Program Review – Year 5, issuing a decision on December 17, 2025 (Year 5 Decision). The decision set the RRES Program tariff rates for project applications received in calendar year 2026 and approved several changes to the RRES Program documents.

This proceeding was initiated pursuant to the Residential Tariff Decision in order to ensure the continued successful implementation of the RRES Program.

C. CONDUCT OF THE PROCEEDING

On April 24, 2026, the Authority issued the Notice of Proceeding in the above-captioned proceeding.

On May 11, 2026, the Authority issued a Notice of Request for Written Comments on the following topics: rate setting; Contractor Compliance Working Group report; and solar production measurement for DC-coupled solar and storage systems. On May 28, 2026, the Authority received six sets of written comments from interested stakeholders.

On August 18, 2026, the Authority held a Technical Meeting to discuss the topics outlined in the May 11, 2026 Notice of Request for Written Comments.

On August 4, 2026, the Authority issued a second Notice of Request for Written Comments on the following topics: program document updates, application fees, and multi-family affordable housing eligibility requirements. On August 19, 2025, the Authority received seven sets of written comments from Program stakeholders.

The Authority issued a Proposed Final Decision on October 1, 2026, and provided an opportunity for Participants to file Written Exceptions.

D. PARTICIPANTS

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

II. LEGAL AUTHORITY

The RRES Program was established pursuant to subsections (b), (d), and (e), and portions of subsection (c) of section 3 of the Public Act 19-35, An Act Concerning a Green Economy and Environmental Protection, now codified in General Statutes § 16-244z. General Statutes § 16-244z(b)(1) required the Authority to establish tariffs for each electric distribution company (EDC) to purchase from residential customers Class I renewable energy from projects located on a residential customer's own premises as well as rates for such tariffs. Additionally, General Statutes § 16-244z(b)(1) permits the Authority to modify the tariff rates based on changed circumstances.

The Authority determined in the Residential Tariff Decision that it would initiate an annual docket to review key RRES Program metrics, including, but not limited to, deployed MW and low- and moderate-income customer participation, and to ensure the Program is "on track to at least maintain historical deployment levels and to deliver a carbon free grid by 2040." Residential Tariff Decision, p. 40.

The Authority reviews the RRES Program design documents and Program Manual, relevant compliance filings, and current tariff rates to determine if and how the RRES Program can and should be modified to better align with the direction provided in the Residential Tariff Decision.

III. PROGRAM OBJECTIVES

In the Residential Tariff Decision, the Authority established the following five Program Objectives to guide the development, implementation, and administration of the RRES Program.

1. The sustained, orderly development of the state's solar industry, ensuring at a minimum that Connecticut's annual historical deployment of residential solar is maintained (i.e., approximately 50-60 MW per year);
2. Achieve a 100% zero carbon electric grid by 2040, including by promoting additional annual deployment of residential renewable energy as needed;
3. Balance participant costs and benefits with non-participant costs and benefits and electric system costs and benefits;
4. Ensure program accessibility for customers, by providing customer protections both explicitly through resources and disclosure forms, and also through simplified program and tariff designs;

5. Encourage increased inclusivity overall, as well as program participation by low- and moderate-income (LMI) customers and customers in environmental justice communities.

Residential Tariff Decision, p. 7.

The Authority relied on the Program Objectives in evaluating the current RRES Program design and assessing any possible changes to be ordered in this proceeding with the objective of better aligning the RRES Program with the Program Objectives and the direction provided in the Residential Tariff Decision. The Authority reaffirms that the Program Objectives shall guide the Program Administrators in their administration of the RRES Program, particularly in instances (1) not explicitly addressed through the approved RRES Program documents or through Authority direction in prior Decisions or motion rulings and (2) where the EDCs are empowered to make administrative changes without PURA approval (See Section IV.N. of the Year 2 Decision).

IV. AUTHORITY ANALYSIS

A. PROGRAM OVERVIEW

In the Residential Tariff Decision, the Authority established a statewide, six-year residential solar program to be administered by the EDCs in their respective service territories. The RRES Program was created to ensure the continued growth of the residential renewable energy market upon the conclusion of the prior Residential Solar Investment Program (RSIP) and the sunsetting of traditional net metering on December 31, 2021. See General Statutes § 16-244z.

The RRES Program gives residential customers the opportunity to sell energy and renewable energy certificates (RECs) from an eligible project, such as a solar photovoltaic (PV) system, for a 20-year term under one of two tariff rate structures: (1) Buy-All; or (2) Netting.

Under the Buy-All tariff, the solar project is provided fixed compensation for all energy and RECs produced over the 20-year term. Compensation is provided to customers in the form of monetary on-bill credits, with the potential for an annual cash out for credits that exceed the customer's utility bills upon customer request.

Under the Netting tariff, projects are compensated for the net energy produced (i.e., all energy production not consumed within the monthly netting period) at the retail electric rate at the time of generation. A customer's billed energy usage is reduced by the energy produced and used onsite. The EDCs provide customers with monetary on-bill credits for any excess energy exported to the grid. Additionally, the EDCs purchase all RECs generated by the project at the applicable REC incentive rate or assess a non-bypassable charge on each kilowatt-hour (kWh) produced.

Table 1, below, provides a summary of the RRES Program Tariff rates and adders for project applications received in calendar year 2026.

Table 1: 2026 RRES Tariff Rates

	Buy-All Rate ($/kWh)	Netting REC Rate / Non-Bypassable Charge ($/kWh)
Eversource	0.3289	-0.0402
UI	0.3289	-0.0402
Income-Eligible Adder	0.055	0.035
Distressed Municipality Adder	0.0275	0.0175

See Year 5 Decision, p. 13.

Table 2 includes a summary of application data from the start of the program in 2022 through June 2026. Over that period, roughly 564 MW have been approved for the Program.

Table 2: RRES Program Applications, January 2022-June 2026

		Total Applications	Total Application kW	Approved Applications	Approved kW
2026 Jan-June	**Eversource**	3,259	31,493	3,417	32,901
	UI	1,006	8,338	855	7,211
2025	**Eversource**	12,850	114,083	12,950	114,838
	UI	3,616	29,239	3,301	26,060
2024	**Eversource**	12,600	101,394	11,996	96,446
	UI	3,185	25,272	2,991	21,441
2023	**Eversource**	17,412	137,691	17,565	138,527
	UI	3,469	27,994	3,373	23,557
2022	**Eversource**	12,460	100,238	11,168	89,570
	UI	2,371	16,579	1,898	13,160
Total	**Eversource**	58,581	484,900	57,096	472,282
	UI	13,647	107,423	12,418	91,430
	Both EDCs	72,228	592,323	69,514	563,712

Eversource Compliance, July 15, 2026, Att. 1; UI Compliance, July 15, 2026, Att. 1; UI Compliance, Jan. 17, 2023, Docket No. 22-08-02, Att. 1.

Table 3 includes a summary of projects deployed from 2022 through June 2026. Over that period, roughly 456 MW of approved projects have been deployed through the program.

Table 3: RRES Program Deployment January 2022-June 2026

		Systems Deployed	Capacity Deployed (kW)
2026 Jan-June	**Eversource**	3,934	34,743
	UI	1,290	10,101
2025	**Eversource**	11,569	99,200
	UI	2,573	20,301
2024	**Eversource**	11,195	87,146
	UI	2,347	17,825
2023	**Eversource**	14,855	119,534
	UI	2,612	19,438
2022	**Eversource**	5,533	44,242
	UI	579	3,894
Total	**Eversource**	47,086	384,865
	UI	9,401	71,558
	Both EDCs	56,487	456,423

Eversource Compliance, July 15, 2026, Att. 1; UI Compliance, July 15, 2026, Att. 1; UI Compliance, Jan. 17, 2023, Docket No. 22-08-02, Att. 1.

B. RATE SETTING

1. General Methodology

General Statutes § 16-244z(b)(1) specifies that the Authority establish rates for renewable energy tariffs based on either competitive solicitations or "the average cost of installing the generation project and a reasonable rate of return that is just, reasonable and adequate", and permits the Authority to "modify such rate for new customers under this subsection based on changed circumstances."

In setting tariff rates for future Program years, the Authority is guided by the three rate-setting objectives outlined in the Residential Tariff Decision. First, the Authority seeks to foster the sustained, orderly development of the state's solar industry. Residential Tariff Decision, p. 37. Second, the Authority seeks to deploy residential renewable energy systems through the RRES Program to help achieve a 100% zero carbon grid by 2040. Id. Third, the Authority seeks to balance RRES Program participant costs and benefits with the costs and benefits to non-participating ratepayers and the electric system as a whole. Id. Ultimately, the Authority weighs all three objectives in establishing RRES Program Tariff rates but errs on the side of setting such rates no higher than necessary to achieve these objectives. Year 1 Decision, p. 5.

When authorizing the Program, the Authority relied on analysis from the Connecticut Green Bank (CGB) to determine the appropriate rate of return needed to

meet the rate-setting objectives. Residential Tariff Decision, p. 38. Based on CGB data and stakeholder testimony, the Authority subsequently determined that the rate of return that was necessary to achieve these objectives was 9 – 11%. Id. Finally, to calculate the ratepayer support necessary to achieve this rate of return, the Authority found the following values necessary to consider: "1) Average upfront installed system cost; 2) the federal Investment Tax Credit (ITC); 3) Ongoing operations and maintenance (O&M) costs; 4) System performance (e.g., capacity factor); 5) Retail electricity rates, including an assumed escalation factor; and 6) the unlevered [internal rate of return (IRR)] for each tariff (i.e., the buy-all and netting tariffs)." Year 1 Decision, p. 6.

In addition, Public Act 25-173, An Act Concerning Energy Affordability, Access, and Accountability, requires the Authority, beginning January 1, 2026, to establish a non-bypassable charge for the Netting tariff of at least 3.25 cents per kWh and adjust the Buy-All tariff rate to be "substantially similar" in value.

2. Stakeholder Comments

Eversource reports that the average installed cost of RRES systems, calculated from PowerClerk application data, was $3.71 per watt DC in 2025 and $3.69 per watt in the first quarter of 2026. Eversource Comments, May 28, 2026, p. 2. For RRES systems installed in UI territory, the average cost was $4.30 per watt DC in 2025 and $4.28 per watt in the first quarter of 2026. UI Comments, May 28, 2026, p. 2.

Sunrun Inc. (Sunrun), Tesla, GoodLeap, IGS, the Connecticut Solar & Storage Association (ConnSSA), and Earthlight Technologies (collectively, the Joint Solar Parties) note several factors creating a challenging market environment for residential solar and impacting RRES deployment figures. Joint Solar Party Comments, May 28, 2026, pp. 1-2. Notably, the 25D Residential Clean Energy Credit for homeowner-owned systems is no longer available as of 2026, which created a "small surge in applications in the second half of 2025" and an expected market contraction in 2026. Id., p. 2. While the section 48E Clean Electricity Investment Credit for third-party-owned (TPO) systems remains available through 2027, the Joint Solar Parties state that the lack of clarity regarding elements of the Foreign Entity of Concern (FEOC) requirements and federal trade policies continue to create uncertainty and price increases. Id. Additionally, the Joint Solar Parties assert that the $0.402 cent per kWh non-bypassable charge and utility rate decreases, in combination, result in the lowest RRES Netting tariff value for participants since the start of the program in 2022. Id., p. 3. RRES applications in the first quarter of 2026 were significantly lower than the first quarter of recent program years (2023-2025), a drop that parallels the national residential solar market trend. Id., p. 4.

The Joint Solar Parties state that Eversource's and UI's residential rates as of July 1 will be approximately $0.236 and $0.266 per kWh, respectively, which are lower than what was modeled in the Year 5 Residential Tariff Model and, if incorporated into the model, would result in a recommended REC adder rather than a non-bypassable charge. Accordingly, the Joint Solar Parties assert that a non-bypassable charge of $0.0325/kWh, as required by Public Act 25-173, would be appropriate for 2027. Id., p. 5. In general, the Joint Solar Parties argue that the Authority should limit significant structural changes

to the program for the 2027 program year as it will be the final full year of the RRES Program. Id., p. 1.

Office of Consumer Counsel (OCC) expresses concern that the loss of the investment tax credit (ITC), which has historically contributed about 11 cents per kWh to residential solar project economics, will put upward pressure on upfront costs. OCC Comments, May 28, 2026, p. 2. OCC argues that the residential solar industry is now mature and robust, and it would not be appropriate to transfer the loss of the ITC to Connecticut ratepayers by increasing compensation rates. Id. If upfront costs continue to increase, OCC recommends PURA consider approving a more limited volume of MW in 2027 rather than increasing ratepayer support per project. Id.

3. Rate Setting Calculations

As in past years, the Authority based its rate setting process on the Residential Tariff Model adopted in the Year 1 Decision. To reflect updated market conditions, the Authority updated the following inputs in the model since it was last used to set 2026 compensation rates in the Year 5 Decision: (1) retail electric rates and historical escalation factor; and (2) average installed cost, using an average of the EDCs' reported RRES project costs per watt in 2025 and 2026. An updated version of the Residential Tariff Model is appended to this Decision as Appendix B, Residential Tariff Model – 2027.

Consistent with the approach taken in the Year 5 Decision, the Authority sets baseline tariff rates based on the model outputs for TPO systems, which remain eligible for the ITC (with certain restrictions) through 2027. Year 5 Decision, pp. 11-12. Additionally, the Authority maintains the 10% target IRR for both Netting and Buy-All systems used in the Year 5 Decision. Id., p. 11.

Additionally, the Authority adjusted the utility escalation rate to be calculated based on a 20-year historical average rather than the 16-year average used in the 2026 Residential Tariff Model. This change was made for consistency with the adoption of a standardized maximum utility escalation rate for contractor use, which is based on a 20-year average of utility rates (see Section D.3).

Applying an IRR of 10% for the Buy-All tariff, the Residential Tariff Model returns a compensation rate of $0.3289, reflecting minimal change in the average installed cost of solar compared to the previous year.

Using a target IRR of 10% for the Netting tariff, the Residential Tariff Model returns a non-bypassable charge of $0.0067 per kWh for Eversource and $0.0657 per kWh for UI. For Eversource, this non-bypassable charge value is below the required $0.0325 per kWh pursuant to Public Act 25-173, Section 9. Accordingly, the Authority authorizes the required $0.0325 non-bypassable charge for RRES systems that apply to the program in Eversource territory in 2027.

The Residential Tariff Model returns a higher non-bypassable charge for UI due to UI's higher residential retail rates. In previous years, the Authority has maintained

equivalent Netting rates for both EDCs despite UI's higher retail rates, largely because RRES Program deployment in UI service territory has historically lagged that of Eversource. Year 3 Decision, pp. 9-10; Year 5 Decision, p. 11. However, recent RRES data indicate that deployment in UI territory has reached or surpassed 20% of the program total, the expected proportion based on each EDCs' total annual load. Projects in UI territory made up about 18% and 25% of the total number of deployed projects in 2025 and the first half of 2026, respectively, and about 20% of total program approved applications in 2025 and the first half of 2026. As a result, the Authority concludes that program maturity and financial value to participants have supported an increased proportion of program deployment in UI service territory despite an increase in the non-bypassable charge in 2026. Accordingly, the Authority authorizes a non-bypassable charge of $0.0657 per kWh for systems that apply to the program in UI territory in 2027.

a. Adder Values

Finally, to promote continuity in the final year of the RRES Program and absent stakeholder comments to the contrary, the Authority will maintain the current income-eligible and distressed municipality adder values for both the Buy-All and Netting tariffs.

4. Summary – 2027 Compensation Rates

A summary of the RRES Year 6 compensation rates is available in Table 4 below.

Table 4: 2027 RRES Tariff Rates

	Buy-All Rate ($/kWh)	Netting REC Rate / Non-Bypassable Charge ($/kWh)
Eversource	0.3289	-0.0325
UI	0.3289	-0.0657
Income-Eligible Adder	0.055	0.035
Distressed Municipality Adder	0.0275	0.0175

C. PROPOSED APPLICATION FEES

Order No. 2 of the Year 5 Decision directed the EDCs to file annually, by August 1, a proposed application fee to cover the estimated administrative costs associated with processing applications, including detailed calculations to justify the proposed fee. Year 5 Decision, pp. 29-30.

Eversource proposes no changes to the current application fee of $163. Motion No. 4, July 28, 2026, Att. 1. Eversource states that it collected $1,520,126 in fees from approximately 9,985 applications over the 12 months ending June 30, 2026 and expects to incur $1,760,735 in program operation costs for 2026. Id. Based on these amounts, Eversource's administrative cost per application is about $176, with a cost of approximately $5 per application for services to enable integrated payment of application fees within the application portal and about $0.75 per application for independent

ombudsperson costs. Id. Eversource notes that the current fee "is offsetting a substantial portion" of its costs to manage the RRES program and does not recommend changes for the final program year. Id.

UI, in contrast, proposes increasing the application fee from $200 to $240. Motion No. 5, July 31, Att. 1. UI reports that it collected $546,149 in application fees across 3,217 applications over the 12 months ending June 2026, and estimates administrative costs of $1,001,682 related to labor and administrative support for processing RRES applications, similar to costs in 2025. Id. UI notes that this reflects lower application volumes in 2026 compared to 2025, resulting in an estimated cost per application of $312. UI proposes increasing the application fee to partially offset the lower fee revenue. Id.

OCC reiterates its position from past RRES Program proceedings that application fees should be set to fully recover each EDC's actual administrative costs without shifting any under-recovery to non-participating ratepayers. OCC Comments, Aug. 19, 2026, p. 3. OCC does not oppose Eversource's proposals to maintain the existing fees, but notes that UI's per-application costs are already significantly higher than Eversource's; thus, OCC argues that UI should provide a clearer breakdown of its fixed and variable administrative cost components and an explanation of why total administrative costs remain fixed despite a decline in application volume. Id.

Sunrun and Goodleap state that the proposed application fees are reasonable. Sunrun and Goodleap Comments, Aug. 19, 2026, p. 2. Save the Sound also supports the proposed fees as striking the appropriate balance among the Program Objectives. Save the Sound Comments, August 19, 2026, pp. 1-2.

The Authority approves Eversource's proposal to maintain the current application fee of $163, as the application fee currently covers a large portion of the company's program administrative costs. The Authority also approves UI's proposed application fee increase from $200 to $240, finding that an increase in the application fee is appropriate to partially offset the shortfall in application fee revenue compared to administrative costs. Although the proposed application fees do not fully cover all RRES Program administrative costs, the Authority's expectation in previous program years has been that application fees will cover most EDC costs associated with administering the Program, to ensure that non-participating customers do not incur undue cost impacts, without creating a barrier to program participation. See Residential Tariff Decision, p. 26; Year 3 Decision, p. 41; Year 4 Decision, p. 15. No stakeholder argued that UI's proposed application fee increase would pose a barrier to participation.

Nevertheless, both EDCs anticipate that similar administrative costs related to application processing in 2026 compared to those incurred in 2025. The Authority presumes that, while some administrative costs are fixed, certain cost components should vary based on application volumes. Thus, lower application volumes should result in lower application processing costs. Additionally, questions remain regarding the extent to which UI's higher administrative costs per project compared to Eversource's are warranted. The EDCs annually recover RRES Program costs through the annual rate

adjustment mechanism (RAM) proceedings (e.g., for 2026, Docket Nos. 26-01-03, Annual Review of the Rate Adjustment Mechanisms of The Connecticut Light and Power Company and 26-01-04, Annual Review of the Rate Adjustment Mechanisms of The United Illuminating Company), where the components of administrative costs and their drivers may be considered more fully. The EDCs may be directed to provide additional justification of the fixed and variable components of RRES Program administrative costs in the relevant RAM proceeding.

1. Interconnection Fee Adder

Order No. 3 of the Decision in Docket No. 22-06-29, PURA Investigation into Distributed Energy Resource Interconnection Cost Allocation (Residential Interconnection Cost Allocation Decision), directs the EDCs to annually file a proposed application fee adder for interconnection applications received the following calendar year. Decision, Dec. 20, 2023, Docket No. 22-06-29, pp. 20-21.

Neither EDC recommends changes to the current application fee adder of $25. Motion No. 6, July 31, 2026, p. 2; Motion No. 7, Aug. 3, 2026, p. 1. Eversource reports that it incurred $1,435,045 in capital costs associated with residential transformer upgrades from July 2025 to June 2026, and collected $157,991 in fee adder revenue over the same period. Motion No. 7, p. 1. While transformer upgrade costs substantially exceeded adder fee revenue, Eversource recommends maintaining the current fee for the final year of the RRES Program and reviewing the allocation of costs for residential DER interconnection as part of a holistic review of renewable energy program design in Docket No. 26-06-04, Implementation of Clean Energy Successor Programs. Id., pp. 1-2. Eversource notes that fee changes "require further updates to program materials and company systems, require communications, education and outreach to program participants, and may have further impacts on participant business operations," and does not recommend undertaking changes that may be in effect for only one year. Id., p. 2.

UI reports that it collected $41,025 in interconnection fee adder revenue from July 1, 2025, through June 30, 2026, while transformer upgrade costs for 14 DER-triggered upgrades over the same period were $236,756, or an annual revenue requirement of $195,688. Motion No. 6, p. 2; Compliance, Aug. 19, 2026, p. 2. UI notes that Order No. 5 of the Residential Interconnection Cost Allocation Decision directs the Interconnection Working Group to assess the effectiveness of the residential DER interconnection cost allocation policy, including potential refinements to the application fee adder and alternative cost allocation approaches. Motion No. 6, p. 1. UI therefore recommends maintaining the existing fee pending completion of the Interconnection Working Group's assessment. Id.

The Interconnection Working Group reviewed the EDCs' interconnection fee data and concludes that no change to the fee adder is necessary at this time. Compliance, Aug. 19, 2026, p. 2. The Interconnection Working Group notes that although the fee adder does not fully cover transformer upgrade costs for UI or Eversource, the monthly bill increase for an average ratepayer to recover transformer upgrade costs is minimal ($0.003 per month for Eversource and $0.0006 per month for UI). Id. Additionally,

Interconnection Working Group members conclude that changes to the current RRES program may not be in customers' interest as the program is ending soon; instead, the implementation of renewable energy successor programs in Docket No. 26-06-04 provides a better opportunity to consider necessary changes to the fee adder and the full cost allocation policy. Id.

Earthlight argues that the definition of "Residential DER" as set forth in the Residential Interconnection Cost Allocation Decision, should be expanded to include multifamily affordable housing (MFAH) projects. Earthlight Comments, Aug. 19, 2026, pp. 1-2. Earthlight asserts that MFAH projects fall within the scope of the RRES Program and are required to pay the same fee adder but do not benefit from the socialization of transformer upgrade costs. Id.

The Authority finds it appropriate to maintain the current $25 interconnection fee adder for the remainder of the RRES Program in order to maintain consistency in the final year. However, the persistent under-collection of fee revenue compared to transformer upgrade costs warrants additional scrutiny to ensure that the residential cost allocation program is achieving its intended objectives. The Authority may consider potential changes to the residential cost allocation policy, including the fee adder, in either Docket No. 26-06-04 or Docket No. 25-03-21, PURA Investigation of Non-Residential Distributed Energy Resource Interconnection Upgrades and Cost Allocation. Additionally, the Authority declines to expand the residential cost allocation program to include larger MFAH RRES projects, which may incur more significant upgrade costs compared to 1 to 4-unit residential projects, without a detailed evaluation of the cost allocation implications.

D. CONTRACTOR COMPLIANCE

In Order No. 25 of the Year 5 Decision, the Authority requested that the Office of Education, Outreach, and Enforcement (EOE) convene and lead a stakeholder working group (Contractor Compliance Working Group, or CCWG) to develop recommendations regarding specific inputs, assumptions, and calculation methodologies that should be standardized across RRES project applications. The CCWG was directed to file a final report of recommendations by March 31, 2026, including proposals for standardizing the starting utility rate used to estimate net year one savings, annual utility rate escalation, and degradation rate; the process and frequency of updating such inputs; the incorporation of standardized calculations and assumptions into the Customer Disclosure Form (CDF) and annual contractor filing requirements; the process for verifying and auditing contractor compliance with standardized calculation requirements; and the date that any proposed standardized calculation requirements should take effect for installers in the RRES Program. Year 5 Decision, pp. 19-20, 36.

On March 31, 2026, EOE submitted the CCWG's final report of recommendations. EOE Corresp., March 31, 2026, CCWG Report FINAL (CCWG Final Report). The CCWG consisted of fifteen members: CGB, ConnSSA, Earthlight Technologies, Eversource, GoodLeap, Ion Solar, Ion Solar Pros (ISP), OCC, SAVKAT, SEIA, SunRun, Tesla, Trinity Solar, and UI, as well as DEEP-BETP as a non-voting member. Id., p. 2. Over the course of ten meetings between January and March 2026, the CCWG discussed and voted on

24 proposals. Id., p. 4. Of those proposals, six received consensus agreement, and eight of the 17 non-consensus proposals received "overwhelming support" (e.g., at least 11 votes in favor out of the 14 total votes). Id. The proposals ultimately recommended by EOE on behalf of the CCWG, stakeholder comments, and Authority analysis are summarized below.

1. Standardized Terminology and Changes to CDF

EOE notes that CCWG members iterated on the terminology to be used in the CDFs and contractor compliance filings throughout the working group process. CCWG Final Report, p. 33. While no formal vote was taken, EOE believes that the CCWG ultimately agreed on appropriate terms to be used. Id. Accordingly, EOE recommends that the following terminology be used consistently throughout the CDFs and contractor compliance filings: Average Starting Utility Rate ($/kWh); Utility Escalation Rate (%), PV Degradation Rate (%), Estimated Year One Net Savings ($), Estimated Multi-Year Net Savings ($), and Estimated Year One Production (kWh). Id.

The Joint Solar Parties, OCC, and Save the Sound supported the proposed standardized terminology. Joint Solar Party Comments, May 28, 2026, p. 6; OCC Comments, May 28, 2026, p. 4; Save the Sound Comments, May 28, 2026, p. 1.

Additionally, EOE recommends that the Authority implement consensus Proposals 16, 21, and 22, and Proposals 17 and 19 (in part), all of which propose changes to certain line items on the CDFs. CCWG Final Report, pp. 33-34. These five proposals are as follows:

> **Proposal 16:** Add line item to the CDFs with a Yes/No checkbox for "Are multi-year net savings estimates provided?"
> **Proposal 21:** On the Direct Owner CDF, replace "estimated net average monthly savings" on the with "Customer Estimated Year One Net Savings."
> **Proposal 22:** On the Third-Party Owner CDF, replace "Escalator rate used to estimate net year one savings" with "Utility Escalator Rate used to estimate Multi-Year Net Savings."
> **Proposal 17** (in part): Add terms and definitions section to the CDFs, and a fillable text box to detail software calculations and/or calculation methodologies
> **Proposal 19** (in part): Add a Yes/No checkbox to the Direct Owned and Third-Party Owned Customer Disclosure Forms (CDFs) for "Is the system being financed through a financing option provided by the contractor? If yes, contractor confirms the financing terms have been discussed with customer." Providing specific financial terms on the CDF is not required.

Id., pp. 33-37.

The EDCs opposed Proposal 19, citing concerns that the CDFs are long and should not be made longer. Id., p. 34. No other stakeholder opposed the proposed

changes to the CDFs.[1] However, Sunrun and Goodleap disagreed with several of specific changes proposed in the EDCs' redlined CDFs filed in compliance with Order No. 1 of the Year 5 Decision; Sunrun and Goodleap's proposed changes are discussed further in Section G of this Decision. Sunrun and Goodleap Comments, Aug. 19, 2026, pp. 2-3. EOE also noted that some of the EDCs' proposed changes to the CDFs must be altered to the extent that the Authority does not adopt all changes proposed in the CCWG Final Report. EOE Comments, Aug. 19, 2026, p. 1.

The Authority agrees that the standardized terminology and related changes to the CDFs will enhance clarity for RRES participants and contractors. Accordingly, the Authority approves EOE-recommended Proposals 16, 21, and 22, and the partial adoption of Proposals 17 and 19.

2. Customer's Annual Electricity Usage

EOE recommends adoption of Proposal 3, which would standardize the methodology for calculating a customer's annual electricity usage for the purpose of determining the percentage of the customer's usage the installed solar system is estimated to offset. CCWG Final Report, p. 9. For customers with 12 months of usage at the property at which the solar is being installed, it must be actual usage over the prior 12 months based on the customer's utility bills; for customers with less than 12 months of usage, contractors may use "any reasonably accurate methodology" and explain in writing to the customer and in compliance filings; and in either case, the customer's annua electricity usage may include allowable additional electrification measures per the RRES Program Manual for the applicable year. Id.

UI opposed the proposal, citing potential conflicts with the Program Manual, which establishes standardized methodology for calculating customer's annual usage. CCWG Final Report, pp. 10, 38; Interrog. Resp. CAE-2. However, EOE denies any conflict as the two calculations have different purposes; the RRES Program Manual specifies the calculation of annual usage for the purpose of system sizing, while Proposal 3 is intended for the estimate of the percentage of annual usage that the system will offset. CCWG Final Report, p. 10. No other stakeholder opposed EOE's recommended standardized approach for calculating the customer's annual electricity usage.

The Authority is unaware of any conflict between Proposal 3 and the Program Manual. As noted by EOE above, the requirements in the Program Manual regarding electricity usage calculation are included for the purpose of system sizing, not for estimating a customer's savings. The Authority approves Proposal 3's methodology for calculating customers' annual electricity usage.

[1] Tesla initially opposed Proposal 19, but upon further consideration agreed with EOE's recommendation include the checkbox but exclude financial terms on the CDFs. CCWG Final Report, p. 29; Interrog. Resp. CAE-21.

3. Utility Escalation Rate

EOE recommends that the Authority standardize the Utility Escalation Rate used in the CDFs and contractor compliance filings based on the language of Proposal 7, which was approved by 12 of 14 CCWG members. CCWG Final Report, pp. 38-39. Proposal 7 specifies that the Utility Escalation Rate used in the CDFs and contractor compliance filings may be no greater than the 20-year historical compound annual growth rate for Connecticut set by the Authority in the RRES annual review docket, based on EDC reported data. Id. EOE recommends that the standardized Utility Escalation Rate be rounded to one decimal point and that the same rate be used for both EDCs. Id.

OCC opposed permitting solar providers to use an escalation rate below the number established by the Authority in its annual RRES docket. OCC Comments, May 28, 2026, p. 4. In general, OCC raised concerns over proposals that would allow optionality for contractors, limiting customers' ability to compare offers on a consistent basis. Id.

The Authority approves EOE's recommendation to adopt Proposal 7. Based on the historical utility rate data provided in this docket, the 20-year historical compound annual growth rate, rounded to one decimal point, is 2.8%. Eversource Interrog. Resp. CAE-31; UI Interrog Resp. CAE-31. Accordingly, contractors may utilize a utility escalation rate no greater than 2.8% for calculating net savings estimates presented to customers. The Authority acknowledges OCC's opposition to allowing contractors to choose different escalation rates, which could limit customers' ability to compare offers on a consistent basis. However, the Authority is concerned with the risk of contractors using higher escalation rates that unrealistically inflate net savings estimates and finds that allowing contractors the option to use a lower escalation poses a comparatively minimal consumer protection risk. Given the uncertainty inherent in estimating future utility rates, the Authority finds it preferable to implement a cap on the assumed escalation rate but maintain flexibility regarding the specific value used.

Finally, the Authority notes that program design for the successor to the RRES Program will be considered in Docket No. 26-06-04, Implementation of Clean Energy Successor Programs, and a methodology for determining and updating compensation rates has not yet been determined. Although the successor program to RRES may not involve the use of the Residential Tariff Model, in which escalation rates, starting utility rates, and other assumptions are updated annually, the Authority may consider the utility of approving annual updates to the allowed assumptions outside of a rate setting model. More broadly, EOE recommended that several of the requirements discussed in this section be carried over to the successor program. The Authority will evaluate and solicit stakeholder feedback on maintaining or adjusting the existing contractor compliance requirements for the successor residential program in Docket No. 26-06-04, which will likely be informed by the implementation of new requirements for the final year of the RRES Program.

4. PV Degradation Rate

EOE recommends that the Authority standardize the PV Degradation Rate by combining Proposals 4 and 5. CCWG Final Report, pp. 40-41. Under these two proposals, the Authority would set the standardized PV Degradation Rate based on the analysis of ISO-NE regarding PV lifetime performance in the most recent NREL Annual Report, rounded to one decimal point, which is currently 0.5%. Id. Alternatively, contractors would be allowed to use the degradation rate of the specific panels chosen by the customer based on the manufacturer's data sheet. Id.

As with Proposal 7, OCC opposed EOE's recommendation to allow solar providers to use panel-specific degradation rates that have not been independently verified against NREL benchmarks. OCC Comments, May 28, 2026, p. 4.

The Authority approves EOE's recommendation for the standardized PV Degradation Rate to be set annually based on the most recent NREL PV Lifetime Project report cited by ISO-NE in its annual DER Forecast, which is currently 0.5%;[2] alternatively, contractors may use the degradation rate of the specific panels used in a project based on the manufacturer's data sheet. The Authority finds that the use of a PV degradation rate for specific panels substantiated by the manufacturer poses little risk that customers would be provided with inaccurate information.

5. Estimated Year One Net Savings

EOE recommends adoption of Proposal 9, which would require contractors to use the following method for estimating Year One Net Savings in the CDF and contractor compliance filings:[3]

a. Estimated Year One Net Savings = [Pre-Solar Utility Costs] - [Post-Solar Utility Costs] + [Solar Cost], where
   i. Pre-Solar Utility Costs = [Customer's Annual Electricity Usage] X [Average Starting Utility Rate]
   ii. Post-Solar Utility Costs = ((Customer's Annual Electricity Usage – Estimated Year One Production) X Average Starting Utility Rate) + (Solar Production Charge X Estimated Year One Production)
   iii. Solar Cost =
      - For Direct Owned without financing: Cost of the system
      - For Direct Owned with financing: Total of payments in Year One
      - For Third-Party Owned: Total of payments in Year One

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[2] The Authority referenced the 2024 NREL Annual Report, available at: https://docs.nlr.gov/docs/fy24osti/90651.pdf, and the ISO-NE Final 2026 DER Forecast, available at: https://www.iso-ne.com/static-assets/documents/100033/2026_final_der_forecast.pdf.

[3] For clarity, both the Estimated Year One Net Savings and Estimated Multi-Year Net Savings methodologies apply only to systems enrolling under the Netting tariff, as Buy-All projects do not directly reduce utility costs and are instead compensated at the approved Buy-All rate for all production. See Earthlight Exceptions, Oct. 15, 2026, p. 9.

Contractors must inform customers that the calculation does not include the value of RECs, if any, but may provide an additional calculation based on the above methodology that adds the estimated value of RECs if the customer will receive the value of RECs. CCWG Final Report, pp. 19-20.

Proposal 9 was supported nearly unanimously by CCWG members. CCWG Final Report, p. 42. Earthlight opposed the portion of the proposal that stated that the value of RECs, if any, would not be included in the calculation.

The Authority approves EOE's recommendation contained in Proposal 9, as it provides a consistent framework for estimating customers' Year One Net Savings while excluding REC benefits that may not be provided directly to customers. Accordingly, contractors will be required to use the above method for estimating Year 1 Net Savings for customers enrolling under the Netting tariff.

EOE also recommended that the standardized calculation methodology be carried over to the RRES successor program. CCWG Final Report, p. 43. Successor program rules, including the continuation or adjustment of any contractor compliance requirements, will be established in Docket No. 26-06-04, Implementation of Clean Energy Successor Programs. The Authority has previously indicated its intent to design the residential successor programs to accelerate paired solar and storage deployment. Corresp., Feb. 27, 2026, Docket No. 25-02-14, Renewable Energy Tariff Program Successor Study, p. 15. Methods for presenting the financial proposition of solar-only and paired solar and storage installation to customers may require additional consideration in that proceeding.

6. Estimated Multi-Year Net Savings

EOE does not recommend requiring contractors to provide Estimated Multi-Year Net Savings, in part because of unresolved questions around how to calculate multi-year savings for projects that include storage. CCWG Final Report, p. 43. If contractors choose to provide Estimated Multi-Year Net Savings, EOE recommends the Authority adopt Proposal 14 as the standardized calculation methodology for the CDF and contractor compliance filing, which received majority approval from the CCWG and states:

> Start with the Estimated Year One Net Savings and over the 20-year tariff term, (i) increase the utility rate by the defined utility escalation rate; (ii) decrease the annual production by the defined PV degradation rate; and (iii) If the system is financed (loan, lease, or PPA), adjust the financing payments by the applicable financial escalations, including any balloon payments. Id., p. 44.

Additionally, EOE recommends that any net savings calculation should include the full costs of the customer's financial products, even if some payments (such as end-of-term balloon payments) are not due within the 20-year term, as many financing agreements have a 25-year term. Id. EOE recommends that in addition to the language above, the Authority require contractors to provide a total calculation (not broken down by year like the 20-year net savings) that provides the full costs of the customer's financial

product. Id. EOE notes that this addition was not voted on in the CCWG but was raised by several members.

The Joint Solar Parties oppose this addition, arguing that systems would continue to provide value after the 20-year tariff term (as Gen. Stat. 16-244z requires the Authority to establish a tariff for compensating RRES customers after the expiration of the 20-year term), but EOE's proposed calculation would incorporate only costs. Joint Solar Party Comments, May 28, 2026, p. 7. Sunrun and GoodLeap further explain that including only costs beyond year 30 would "heavily skew the multi-year savings estimate in a way that is both confusing and misleading for customers," because both bill savings and solar costs are expected to increase over the contract term. Sunrun and GoodLeap Exceptions, Oct. 15, 2026, pp. 3-4.

OCC supported EOE's suggested approach for calculating but not requiring multi-year net savings estimates. OCC Comments, May 28, 2026, p. 4.

The Authority approves the adoption of Proposal 14 with modification. Customers should be aware of the full extent of financing costs, even if some costs extend past the end of the 20-year RRES tariff term. Therefore, estimates of multi-year net savings shall be required to include the full cost of the customer's financial products. Nevertheless, the Authority recognizes that incorporating only costs and excluding projected bill savings after the 20-year term could result in misleading savings estimates. General Statute 16-244z(c)(1)(E) requires the Authority to establish a tariff for the purchase of energy on a cents-per-kWh basis from existing RRES systems after the expiration of the tariff term, but a specific tariff has not yet been established, making the full customer value uncertain. Netting systems that continue to operate after the 20-year RRES term would, at a minimum, provide utility bill savings by reducing the customer's billed usage by the amount of solar generation directly consumed onsite.[4] Contractors may include this value (i.e., the amount of solar generation consumed behind the meter, multiplied by the assumed utility rate in effect) in the multi-year net savings estimates provided to customers, and shall provide an explanation in the CDF and their annual contractor compliance filings describing how the estimate was derived and the components included.

7. Starting Average Utility Rate

EOE reports that standardization of the starting utility rate used to calculate estimated Year One and Multi-Year Net Savings was the most challenging topic discussed in the CCWG, with no consensus reached. CCWG Final Report, p. 45. Several methodologies could be used to standardize the Average Starting Utility Rate, each with benefits and drawbacks. Id. In general, the starting utility rate selection can either prioritize consistency across customers or accuracy in reflecting an individual customer's actual utility costs, but not both. Id., p. 46.

[4] Based on hourly load and generation profiles, for a typical residential customer, Eversource previously estimated that about 40% of generation annually would be directly consumed onsite. See Eversource Comments, Aug. 5, 2025, Docket No. 25-02-14, Renewable Energy Tariff Program Successor Study, p. 2.

The main methodologies discussed by the CCWG, both based on historical data, were (1) calculation of an average rate across all customers (or a subset of customers), and (2) a customer-specific calculation based on each customer's average rates. Id., p. 45. An average historical rate offers consistency across customers and reduces the risk of errors but may not reflect a customer's actual electricity costs (particularly for customers on third-party supply rates) or capture variability in rates. Id. EOE also noted that the choice of starting utility rate must consider whether to calculate an all-in rate or break out rate components; for example, applying the standard service rate for customers who utilize a third-party supplier. Id., pp. 45-46.

As the CCWG did not reach consensus, EOE proposes that the Authority authorize several methodologies for the Starting Average Utility Rate and mandate that contractors transparently describe the approach used in writing to customers and in their contractor compliance filings. CCWG Final Report, p. 47. EOE suggests allowing the following methodologies:

1. Standardized rates set by the Authority in the RRES Program annual review docket: per-EDC rate forecast used in the Residential Tariff Model for the following calendar year.
2. Customer-specific 12-month historical average: based on the all-in utility rate over the past 12 months of usage, using the customer's actual utility bills. If the customer uses a third-party supplier, contractors must explain how that rate will affect net savings calculations.
3. Software calculation methodology: any reasonably accurate methodology used by software designed to calculate an average starting utility rate for the customer based on their location and usage history.

CCWG Final Report, p. 47.

To ensure transparency, EOE recommends that (a) if a contractor uses the standardized rate described in option 1 above, no explanation other than the source of the rate is required; and (b) if a contractor uses a customer-specific historical average rate or a software methodology, as described in options 2 and 3 above, they must explain in writing to the customer and in their compliance filings the methodology used, including detailing all parameters of the methodology and any parameters that are not included in the methodology. CCWG Final Report, pp. 47-48. The parameters that must be explained include distribution rate, transmission rate, supply rate, non-bypassable charges, discounts (including LIDR), sources of the information, and whether the customer's rate is different than the current standard service rate. Id.; Interrog. Resp. CAE-13.

The EDCs argue that the starting utility rate should be required to be based on historical rates rather than third-party supplier rates, which can exceed standard service rates and can be variable. Eversource Comments, May 28, 2026, p. 3; UI Comments, May 28, 2026, p. 3. Additionally, the ECCs recommend careful consideration of allowable

methods for calculating the starting utility rate for customers enrolled in a LIDR; Eversource states that customers on a LIDR should not be provided with a savings estimate based on non-LIDR utility rates. Id.

OCC opposes allowing solar providers to calculate savings based on a customer's specific rate over the prior 12 months, asserting that a customer could achieve a significant portion of those calculating savings by returning to standard service or contracting with a lower-cost supplier. OCC Comments, May 28, 2026, pp. 4-5. OCC asserts that solar savings should be measured against a realistic and consistent baseline rate. Id.

The Joint Solar Parties emphasized that no method for determining a starting utility rate is perfect, and multiple defensible approaches each have benefits and drawbacks. Joint Solar Parties Comments, May 28, 2026, pp. 7-8. The Joint Solar parties state that a rigid methodology that cannot account for variability in utility rates will inevitably be "wrong" at some point during the year, creating risks for participants and contractors. Id. Regarding the proposal to require the use of utility rates set by the Authority in the annual RRES docket, the Joint Solar Parties note that the Eversource rate used on the customer disclosure form and other materials in 2026 would have been $0.31 per kWh, compared to an actual rate in July 2026 of under $0.24 per kWh.[5] Id. Conversely, using the current utility rate from recent bills may not properly account for changes from seasonal supply rates or RAM charges. Id. As a result, the Joint Solar Parties do not support EOE's recommendation to authorize a set of allowable methodologies, because such methodologies would already be wide-ranging but may still preclude contractors from using potentially equally valid methodologies. Id., p. 9. The Joint Solar Parties support EOE's recommendation for transparency regarding the starting utility rate chosen, but express concern that EOE's proposed language in the fillable text box on the CDF may be too complicated for customers to understand and may be better suited for contractor compliance filings. Id.

The Authority appreciates the CCWG's thoughtful discussion of the merits of various options for starting utility rates. As discussed by several stakeholders, there are tradeoffs between standardization of the starting utility rate, which offers consistency across customers, and flexibility, which can allow for more accuracy in reflecting an individual customer's value proposition and adjusting to changes in utility rate components.

First, the Authority shares stakeholders' position that customers enrolled in LIDR should not be presented with savings estimates based on a non-discounted starting utility rate, which would inflate savings estimate and present consumer protection concerns for vulnerable customers. Accordingly, the Authority will require that the starting average utility rate used for customers enrolled in LIDR reflect the customer's actual discounted rate, whether through a manual adjustment to the starting utility rate or a software methodology that accounts for the customer's specific discount level.

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[5] The Authority notes that the Eversource average rate over the entire year in 2026 used in the Residential Tariff Model – 2027 is $0.27 per kWh.

Next, the Authority finds that contractors should have flexibility to choose either option 1 above (the standardized rate set by the Authority in the RRES Program annual review docket) or option 3 (a reasonable software methodology). As argued by OCC and the EDCs, the Authority determines that net savings estimates should not be based on third-party supply rates, which can be variable and may overestimate the savings attributable to solar. Thus, the Authority does not approve option 2 (a customer-specific historical 12-month average based on actual utility bills), as the primary purpose of a customer-specific average appears to be to account for either third-party supply rates or LIDR.

The Authority finds it appropriate to allow contractors to use either a standardized average starting utility rate set by the Authority or a reasonable software methodology, as each method has benefits and drawbacks. A requirement for contractors to use a single starting utility rate in all cases poses risks that the rate may become out of date over the course of a year. The Residential Tariff Model uses projected average rates based on each EDCs' average rates over the previous year plus escalation factor applied; if the previous year's rates are anomalous, this would skew the starting utility rate assumption and resulting net savings estimates for the following calendar year. Although the average starting utility rate from the Residential Tariff Model may often be a reasonable assumption, the model's purpose is to generate average compensation rates for the program, not to provide detailed financial savings estimates to customers. Contractors may have more up-to-date information available when presenting solar proposals to customers. Software approaches for determining starting utility rates can address these concerns by updating rates more frequently than once per year, and can also offer starting rates more tailored to an individual customer's usage profile (for example, if a customer uses more electricity in the winter than in the summer). The Authority does not deem it appropriate to prevent the use of such methods.

Nevertheless, transparency in disclosing the assumptions used by software methods is important, for both presentation to customers and in contractor annual compliance filings. Accordingly, whether contractors use the starting utility rate set by the Authority in the Residential Tariff Model for the following calendar year or a reasonable alternative software methodology, contractors shall be required to clearly explain which starting utility rate is used and how it may differ from the rate seen on the customer's utility bills. If a software methodology is used, contractors must also include an explanation of what the starting utility rate reflects (e.g., current utility rates or an average over a period of time), and whether any customer discounts are included in the starting rate. Additionally, contractors should provide a more detailed explanation of the software methodology used, including all inputs and assumptions used and their sources, in their annual compliance filed with EOE. Such explanations shall be provided in the narrative explanation of any calculation methodologies included in the Financial Benefits Summary Sheet (Sheet Narrative).

8. Timing of CDF Presentation to Customers

The CCWG did not reach consensus regarding when the CDF should be presented to customers in relation to installation contract signing. CCWG Final Report, pp. 30, 48. EOE states that most contractors currently present the CDF to customers after the solar installation contract is signed because they generate the CDF in PowerClerk along with the interconnection application. Id. EOE and OCC argue that customers should instead receive the CDF days in advance of contract signing, which would allow time to review thoroughly, ask questions, and compare offers from other contractors. Id. The CCWG contractors, conversely, assert that the CDF should be presented to customers "immediately prior to and contemporaneously with the solar contract" as a summary of the contract terms. Id., p. 31. Some contractors present and close solar sales in a single visit; others include an initial visit and follow-up with the customer-specific proposal, but with insufficient time to provide the CDF in advance of contract signing. Id. Contractors also state that CDF is not completed early in the sales process because some information (such as shading or financial arrangements) may not be confirmed, and earlier presentation could increase the risk of inconsistencies with the final contract. Id. EOE opines that presenting the CDF at the time of contract signing, while not its preferred solution, would still be an improvement over current practice. Id., p. 48.

The Joint Solar Parties argue that providing the CDF contemporaneously with the solar contract does not prevent customers from taking time to review or seeking additional quotes, as not all contracts are signed immediately. Joint Solar Party Comments, May 28, 2026, p. 10. Additionally, the Joint Solar Parties state that the contract must be generated to have proper information on the CDF, and the contract also contains important information for customers; thus, "it would be unwise to force customers to sit with incomplete information… for a regulated period of time before receiving the rest of the already-generated package that is necessary for them to make an informed decision." Id. The Joint Solar Parties note that Connecticut law mandates a minimum three-day cancellation period for any home improvement contract.

OCC "unequivocally" maintains that customers must receive the completed CDF in advance of signing a solar installation contract rather than at the time of signing, underscoring that solar installation is a significant, long-term financial commitment. OCC Comments, May 28, 2026, p. 5. Additionally, OCC expresses concern that some solar contractors present and close sales within a single visit. Id. OCC argues that the record demonstrates that contractors can accommodate customers who ask for more time, so advance delivery of the CDF is operationally feasible and should be the default without customers needing to request additional time to review. Id.

In other states with customer disclosure form requirements, contractors report that the general practice is to provide completed disclosure forms to customers at the same time or prior to the execution of the solar installation agreement, though the timing may vary. For example, programs in Massachusetts and New Jersey do not specify when the CDF must be provided, but it must be completed before applying to the program and is typically provided to customers along with the solar contract and other materials. Sunrun Interrog. Resp. CAE-20; Earthlight Interrog. Resp. CAE-20. The Illinois Shines program

requires that the disclosure form is executed by the customer prior to the execution of the customer contract and commencement of the incentive application. Tesla Interrog. Resp. CAE-20. In other states, the disclosure process may occur after the customer signs a solar contract, as part of the interconnection or program application process. Ion Solar Pros Interrog. Resp. CAE-20; Tesla Interrog. Resp. CAE-20. In California, the California Solar Consumer Protection Guide is signed before the customer signs any contract, but it does not include financial or system design information; a Solar Energy System Supporting Information Document is signed after the customer signs the final contract and includes contract terms and system design information. Tesla Interrog. Resp. CAE-20.

The Authority determines that contractors shall be required to present the CDF contemporaneously with the solar installation contract. CDF presentation at the time of contract signing represents an improvement over current practice and will advance the fourth program objective of ensuring program accessibility by providing customer protections through resources and disclosure forms. The Authority determined that customers should have access to complete financial and production documentation, as well as the CDF, before signing a solar installation contract. Year 5 Decision, p. 20. Both the CDF and contract itself are necessary to present customers with complete financial, production, and other key terms, as well as to avoid inconsistencies between the two documents. Thus, the Authority will not mandate a specific waiting period between CDF presentation and contract signing. However, all RRES customers should be notified that they may take additional time to review the contract and CDF before signing the contract. Contractor comments suggest that this is feasible, as some customers do request time to review the contract terms before signing; the program materials should make clear that this is an option available to all customers. Accordingly, the EDCs shall update the signature portion of the CDFs to specify that customers may take time to review the contract terms before signing and, per General Statutes 42-135a, may cancel home improvement contracts with no penalty at any time prior to midnight of the third business days after signing.

Beginning January 1, 2027, contractors will be required to provide the CDF to customers contemporaneously with the solar installation contract. Rather than generating the disclosure form within PowerClerk as part of the program and interconnection application, contractors must upload a signed disclosure form with the RRES application.

9. Implementation Timing

EOE recommends that change to the CDFs (proposals 16, 17, 19, 21, and 22) be made as soon as possible, but no later than July 1, 2026, and that all other proposals be implemented no later than January 1, 2027.

OCC recommends that the effective date for the requirement for CDF before contract signing, if adopted, and other proposals be as near-term as practicable, noting that the length of time required depends on the complexity of the changes. OCC Comments, May 28, 2026, p. 5.

The EDCs recommend allowing sufficient time for implementation in PowerClerk and installers' internal processes. Eversource Comments, May 28, 2026, p. 4; UI Comments, May 28, 2026, p. 3. Eversource notes that at times, the EDCs have utilized a transition period of one to two months for accepting updating disclosure forms, during which either version of the form may be accepted. Eversource Comments, May 28, 2026, p. 4.

The Joint Solar Parties argue that changes should be considered for the 2027 program year, and an appropriate amount of time should be given for contractors to adjust their business operations. Joint Solar Party Comments, May 28, 2026, p. 6. Specifically, they assert that contractors should have a minimum of 90 days from Authority approval of changes and availability of a CDF to make the necessary changes to their operations, and that there should be flexibility for contractors who may take additional time to comply. Id.

The Authority determines that, for consistency, all changes to contractor requirements discussed above shall take effect at the start of the 2027 program year. However, to provide a transition period for program participants, the EDCs shall accept either the 2026 or 2027 version of the CDF until February 1, 2027. Additionally, projects with contracts signed prior to January 1, 2027 may use the 2026 version of the CDF. See Sunrun and GoodLeap Exceptions, Oct. 15, 2026, pp. 4-5.

The EDCs shall file clean and updated CDFs as part of the December 1, 2026 compliance filing of updating program documents incorporating the direction in this Decision. Additionally, the EDCs shall notify participating applicants of the updated requirements through an email notification, PowerClerk banner, and updates to the information provided on the EDCs' RRES Program webpages no later than December 1, 2026, and file compliance in the instant proceeding once complete. No later than January 1, 2026, the EDCs shall make the necessary updates to the RRES PowerClerk application and file compliance once complete. Finally, the EDCs shall include an overview of the contractor compliance requirements in the annual webinar with solar developers pursuant to Order No. 16 of this Decision.

E. DC-COUPLED SOLAR AND STORAGE SYSTEMS

1. UI Motion

In a motion filed with the Authority, UI requested clarification on how to apply the non-bypassable charge and incentive adders and certify Renewable Energy Credits (RECs) for customers with direct-current (DC) coupled renewable generation systems that include both solar PV and battery storage using a shared inverter. Motion No. 24, May 5, 2026, Docket No. 25-08-02, Annual Residential Renewable Energy Solutions Program Review – Year 5. UI states that the implementation of non-bypassable charges, which are assessed per kWh of total system production, conflicts with the requirement for

metering configurations to accommodate DC-coupled batteries that provide home backup during grid outages.[6]

UI asserts that because the solar and storage operate on the DC side of a shared inverter with a single alternating-current (AC) output delivered at the point of interconnection, there is no revenue-quality metering on the DC side capable of independently measuring (1) PV generation delivered to the grid, (2) battery charging from the PV array, (3) battery discharging energy delivered to the inverter or grid, (4) battery charging from the grid, and (5) emergency load backup during outages. Id., pp. 2-3. UI states that this "materially impacts" the assessment of REC adders and non-bypassable charges, which are determined based on solar PV production. Id., pp. 2, 4.

UI also claims that the DC-coupled configuration introduces uncertainty to the certification of Class I RECs, because metering configurations cannot distinguish between renewable generation delivered to the grid and energy discharged from storage. Id., pp. 3-4. If batteries charge from the grid, then the energy discharged is not solely generated from a Class I source. Id. Thus, unless the charging source is clearly restricted so that storage is charged exclusively from renewable generation, there is a risk of conflicting with statutory Class I REC requirements. Id., p. 4.

Finally, UI notes that its metering diagrams require that "Islanding accomplished by multiple isolation devices must be open transition and synchronized… [t]he production and billing meter cannot be energized during islanding." Motion No. 24, May 5, 2026, Docket No. 25-08-02, p. 5; Motion No. 7, Att. 13A, p. 3. UI states that installers must implement open transition devices on the line side of the production meter to comply with this requirement. Motion No. 24, May 5, 2026, Docket No. 25-08-02, p. 5. As a result, UI states that any backup load served by these devices is also on the line side, causing the production meter to record combined inverter output and backup load, rather than solely solar generation. Id.

UI proposes that for impacted DC-coupled systems, until a viable solution exists to measure solar production separately from battery storage or other loads, (1) non-bypassable charges and incentive adders be calculated using a proxy production quantity based on the approved inverter nameplate rating and a standard production factor, and (2) RECs associated with these projects not be sold into the NEPOOL GIS market to avoid potential noncompliance with the sale of Class I RECs in the market. Id., pp. 7-11. UI does not recommend the use of inverter data to calculate non-bypassable charges and incentive adders, stating that it would be unable to validate the accuracy of third-party

[6] UI cites Order No. 23 of the Year 5 Decision, which directed the EDCs to file updated RRES program documents incorporating the approved program modifications in the Year 5 Decision. UI states that Order No. 23 "requested proposals for system configurations to provide home backup during grid outages." Motion No. 24, Docket No. 25-08-02. However, the Year 5 Decision did not direct any changes to the metering diagrams or request proposals for system configurations to provide home backup during grid outages. Order No. 18 of the Year 2 Decision, which was due May 1, 2023, did direct the EDCs to provide at least one proposal for system configurations with the ability to provide home backup during grid outages, including DC-coupled solar plus storage systems under the Buy-All tariff. Year 2 Decision, p. 36.

owned, customer-sited inverters; would be required to manually enter data in different vendor formats into its billing system; and would be unable to gather inverter data from developers that go out of business. Id., pp. 8-9. Finally, UI is unable to provide an estimated cost for adjustments to its billing systems for automated calculation and tracking using the proposed proxy production method, and states that it "could administer the proxy through an auditable external calculation and periodic bill adjustment or true-up process" pending updates to enable full automation. Id., pp. 9-10; Interrog. Resp. CAE-4.

UI identifies 160 operational RRES projects, or approximately 1.8% percent of the current RRES project population as of April 2026, that are potentially affected by this issue. Motion No. 24, Docket No. 25-08-02, p. 4. In Eversource territory, 325 projects are DC-coupled solar and storage systems, about 1.5% of the 20,900 total RRES projects with applications submitted in 2024 or later (when Eversource began tracking whether storage systems are AC- or DC-coupled). Interrog. Resp. CAE-5. Both EDCs state that they currently treat DC-coupled solar and storage systems no differently than typical RRES systems, where non-bypassable charges and adders are applied based on production meter reads. Eversource Interrog. Resp. CAE-9; UI Interrog. Resp. CAE-9. However, UI reports that, since October of 2025, it has stopped uploading the RECs associated with DC-coupled RRES systems into the NEPOOL GIS system. Tech Mt'g Tr., Aug. 18, 2026, 53:20 – 54:9.

2. Stakeholder Comments

Eversource does not share UI's concerns regarding DC-coupled solar and storage systems, asserting that metering the combined output of a DC-coupled system is generally acceptable and consistent with Connecticut's clean energy goals. Eversource Comments, May 28, 2026, p. 5. Eversource notes that the combined operation of these resources will generally result in less output recorded due to roundtrip ESS losses, but such losses are "fairly negligible" and would have commensurate impacts on both credits and non-bypassable charges for customers enrolled in the netting tariff. Id. Eversource also points out that, although the RRES Program rules do not prohibit systems from charging from the grid, customers do not have a financial incentive to do so during normal operations as they would incur roundtrip energy losses on energy purchased from the grid. Tr., 35:2 – 19.

In Eversource's view, the only situation that would create significant impacts on the balance of program costs is a configuration where a customer is serving load (other than parasitic load) behind the production meter, which would reduce the amount of RECs reported and allow the customer to avoid non-bypassable charges while still benefitting from reducing load and exporting excess generation through the revenue meter. Eversource Comments, May 28, 2026, p. 6; Tr., 36:7 – 23. However, Eversource states that this operation is already prohibited by the RRES Program rules and metering requirements, which require that "[e]xcept for the parasitic load utilized to operate the coupled solar and storage system, there shall be no load connected behind the Utility production meter." Id.; Order No. 23 Compliance, Jan. 22, 2026, Docket No. 25-08-02, Att. 12, p. 4. Finally, Eversource does not consider it necessary to meter the output of

combined solar and storage systems to credit or charge customers for operating distributed energy resources during power outages as outage periods represent small portion of expected operations, a position with which UI agreed. Eversource Comments, May 28, 2026, pp. 6-7; Interrog. Resp. CAE-29. While Eversource notes that it is possible customers have installed configurations that do not comply with the Program requirements, the current impacts of such systems that adhere to current RRES Program requirements are likely not significant enough to justify the costs and time required to implement the UI's proposed alternative billing solution. Id.

The Joint Solar Parties dispute UI's characterization of the issues posed by DC-coupled systems, asserting that the RRES Program requirements for wiring and charging controls already allow for measurement of all generation produced by PV systems. Joint Solar Party Comments, pp. 14-15. The Joint Solar Parties state that installers place the production meter directly upstream of the shared inverter and commission the battery to only charge from the DC-connected solar PV array, ensuring that only PV-generated energy passes across the production meter. Id., p. 15. Sunrun subsequently clarified that, although systems generally charge from solar by default because significant grid charging is not economically advantageous, storage does charge from the grid in advance of storm events. Tr., 88:4 – 22. However, any grid charging would be recorded by the bidirectional production meter and netted against the total export from the combined system, mitigating concerns that energy imported from the grid would be reported as Class I renewable generation. Tr., 47:15 – 49:23. In accordance with Section T of the Program Manual, the net production meter reading is used for the assessment of REC adders and non-bypassable charges as well as REC reporting, such that any grid imports would be excluded when using the net read of the production meter between the two channels. Sunrun Corresp., Aug. 18, 2026, p. 4.

The Joint Solar Parties argue that all three of UI's concerns are unfounded, as the wiring and charging configuration already required for RRES participation (1) ensures that the only energy measured by the production meter is Class I REC compliant, except for the minimal amount of energy the storage system had when it was installed; (2) captures all energy produced by the PV system for the purposes of non-bypassable charge calculation, with the exceptions of parasitic load and the minimal amount of PV generation that the battery has stored but not yet discharged; and (3) counteracts the islanding concerns raised in UI's motion. Id. Finally, the Joint Solar Parties argue that not selling RECs from any DC-coupled system is "unnecessary and would reduce ratepayer benefits," and express concern about how a standardized capacity factor approach would be implemented and potentially affect customers. Id., p. 16.

The Connecticut Green Bank (CGB) notes that DC-coupled systems "deliver cost and efficiency benefits by routing solar energy directly to the battery before a shared inverter converts it to alternating current," and recommended against measures that would unfairly disadvantage DC-coupled systems or slow solar and storage deployment. CGB Comments, May 28, 2026, p. 4. CGB has been authorized to create a pilot program to support solar and storage deployment among customers with existing solar, and argues that excluding DC-coupled systems from full participation would limit the

usefulness of resulting recommendations. Id. Instead of UI's recommended solution, CGB proposes (1) certified inverter firmware disaggregation, using separately logged PV and battery flows, and (2) DC-side revenue-grade metering for new systems, using a pre-inverter where needed. Id., p. 5.

OCC does not oppose a "reasonable interim proxy-based approach" to calculating non-bypassable charges and incentive adders for affected DC-coupled systems, as long as it is applied consistently, does not systematically overstate or understate production in ways that produce inequitable outcomes, and is treated as expressly interim until more accurate measurement solutions become available. OCC Comments, May 28, 2026, p. 6. OCC agrees with UI's proposal to not sell RECs from DC-coupled systems until a reliable measurement solution is in place, expressing concern over potential REC noncompliance that could "undermine the credibility of the program and expose participants to market integrity issues." Id., pp. 6-7.

3. Authority Analysis

The Authority is unconvinced that DC-coupled solar and storage systems participating in the RRES Program pose significant concerns for REC integrity or proper accounting of customer compensation and charges. Moreover, UI's proposed solution would create administrative burden and cost while reducing ratepayer benefits from REC sales. As a result, the Authority declines to approve changes to the program rules for DC-coupled systems.

With respect to Class I REC integrity, the Authority finds that the UI's concern is mitigated by the Program Manual's requirement that REC reporting is based on the monthly net value of the production meter's generation and consumption channels, such that that any charging from the grid would be netted against the total amount exported from the combined system. Compliance, Jan. 22, 2026, Docket No. 25-08-02, Att. 1B, p. 31. Thus, the net production meter reading captures only the amount of energy generated by the PV system. The Authority does not agree that this violates requirements for Class I renewable eligibility.

For the purposes of calculating REC adders and non-bypassable charges, DC-coupled system output measurements would be impacted somewhat by parasitic load and roundtrip energy losses, but these factors are unlikely to adversely impact program operations or the balance of program costs. The exception to this is configurations where load is connected behind the production meter, which would cause inaccurate production measurements for non-bypassable charge assessment and REC reporting. Notably, this configuration is prohibited in Eversource's meter wiring diagrams and is an important safeguard to ensure that the production meter is accurately recording the full amount of energy produced. For UI, however, questions remain as to whether the metering diagrams and guidelines contain this same restriction, and if so, whether the rule is enforced. As Sunrun notes, UI's metering diagrams indicate that both the main and alternate point of connection would be connected to the automated grid isolation system after the production meter, so that all energy produced would flow through the production meter before serving load. Tr., 51:17 – 52:6; Motion No. 7, Att. 13A, p. 4. However, UI

reports that it is aware of systems where the production meter and revenue meter are directly in series, such that all load is behind the production meter. Tr., 52:7 - 19.[7] To the extent that systems are being installed with load connected behind the production meter, this configuration would contradict the purpose of a production meter and the Program Manual's requirement that the production meter exclusively measures the output of the system.

Accordingly, to ensure that PV production is accurately recorded and for consistency with Eversource's metering rules, UI shall adjust its metering diagrams to require that no load (except for parasitic load utilized to operate the coupled solar and storage system) is connected behind the production meter. UI shall file its updated metering diagrams for Authority review and approval no later than December 1, 2026. Additionally, UI shall meet with industry stakeholders prior to filing its updated metering diagrams with the Authority, and incorporate any stakeholder feedback, to ensure that any updated metering provisions do not impose undue barriers to program participation.

Additionally, if the EDCs have evidence of a substantial number of RRES systems that have load connected behind the production meter in violation of the allowed metering configurations, the EDCs may propose a remedy for that limited number of systems rather than for the entire technology class. Based on the Authority's review of the DC-coupled inverters in operation in the RRES Program, such inverters are technologically capable of measuring and reporting each input channel to separate PV and battery power flows. Interrog. Resp. CAE-20. As stated above, the scope of this specific issue does not warrant billing changes; however, to the extent that the EDCs are aware of customer configurations with load connected behind the production meter, inverter data may be used to verify compliance with RRES program rules. In general, the Authority is interested in ways that inverter data may be better utilized in current and future clean energy programs to provide visibility into DER operations without the need for additional equipment installation.

Moreover, for an issue that is likely minor, UI's proposed solution would be costly and administratively burdensome. The cost and timeline to implement UI's proposed billing solution based on a proxy production method are uncertain, but likely substantial based on previous billing upgrade projects. UI Interrog. Resp. CAE-4; Eversource Interrog. Resp. CAE-6. The Authority is also concerned that UI is unable to provide a cost estimate for a measure that it proposed on its own initiative. Id. Additionally, the proposed proxy production method may not be sufficiently accurate for the purpose of estimated compensation for individual participants. UI states that the variance between PowerClerk estimated generation and actual generation recorded by the production meter was only 1% on average, but the sample of project data provided indicates that production

[7] UI states that the metering diagrams guidelines originally prevented load behind the production meter, but the relevant provision was removed following the Year 5 Decision's direction to refile metering guidelines and subsequent discussions with developers regarding the allowance of an alternate point of connection for whole-home backup systems. Tr., 38:22 – 39:25. The Authority is unaware of whether the potential implications for load connected behind the production meter were contemplated at that time.

estimates can vary from measured production by up to 11% for individual systems. UI Interrog. Resp. CAE-3.

The RRES Program compensates participants for energy and RECs, with RECs sold into the NEPOOL GIS market and the resulting revenue credited to all ratepayers through the non-bypassable federally mandated congestion charge (NBFMCC). Gen. Stat. §§ 16-244z(b)(1), 16-244z(d); Residential Triff Decision, p. 20. As concerns around REC compliance appear to be minimal, the Authority is not inclined to approve a proposal that would forgo REC revenue and the associated ratepayer benefits, estimated at about $255,000 per year for currently operational impacted systems across both EDCs. Eversource Interrog. Resp. CAE-10; UI Interrog. Resp. CAE-10. Importantly, UI states that it has already independently ceased sales of RECs from DC-coupled systems into the NEPOOL GIS REC market. The Authority directs UI to resume selling RECs from PV systems enrolled in RRES with DC-coupled storage, effective immediately, and file compliance notifying the Authority once sales have resumed. In its filing, UI shall provide the amount of total generation (MWh) associated with DC-coupled RRES systems that has been excluded from UI's uploads to NEPOOL GIS.

F. MFAH ELIGIBILITY REQUIREMENTS

The EDCs highlight that the current MFAH eligibility requirements accommodate a growing number of large, ground-mounted systems. Eversource Comments, May 28, 2026, pp. 7-8; UI Comments, May 28, 2026, pp. 4-5. The EDCs note that such projects are eligible to receive the Buy-All incentive rate and income-eligible adder, which exceeds what similar large commercial projects would receive through the Non-Residential Renewable Energy Solutions (NRES) or Shared Community Energy Facilities (SCEF) Programs. Id. As such, the EDCs suggest that the Authority consider adjusting siting or sizing requirements to focus RRES MFAH eligibility on solar PV systems that are located on or at the property they serve, potentially by restricting the system siting to the same interconnection point as the building load. Id.; Tr., 74:14 – 21. While the current RRES rules require that projects be located on the eligible property, the EDCs note that in some cases, the property is large enough that the system's proposed siting requires a new service at a separate interconnection point from the existing building load. Eversource Comments, May 28, 2026, pp. 7-8; UI Comments, May 28, 2026, pp. 4-5. Alternatively, the EDCs recommend consideration of a different Buy-All incentive rate setting methodology for the MFAH market segment to better align with the program objective to balance participant and nonparticipant costs. Id.

CGB reports that, in its experience financing and supporting affordable housing projects, larger MFAH projects (which CGB classifies as 100 kW or above) have installed costs more similar to the broader RRES market than to NRES or SCEF projects. CGB Comments, Aug. 19, 2026, pp. 1-2. Specifically, the average cost of MFAH projects over 100 kW selected in CGB's February 2026 RFP for project installations was $3.64 per watt—comparable to the $3.69 and $4.28 installed cost per watt in the first quarter of 2026 for Eversource and UI RRES projects, respectively. Id. CGB states that the larger size of some MFAH projects "does not necessarily translate into commercial-scale economics" because MFAH projects often involve more complex building configurations;

multiple roofs or electrical systems tenant benefit allocation requirements; affordable housing financing constraints; and coordination between property owners, housing agencies, lenders, and tenants. Id. Accordingly, CGB expresses concern that modifications to MFAH sizing or siting requirements or a reduced Buy-All rate could limit solar deployment opportunities for affordable housing properties and reduce the benefits received by low- and moderate-income tenants. CGB also suggests that changes to RRES MFAH eligibility could impact the ESS Program's objective to deliver resilience to underserved customers. Id., pp. 2-3.

Earthlight opposes the EDCs' suggestions to adjust siting and sizing requirements or the Buy-All rate setting methodology, stating that it would introduce additional complexity into the MFAH segment of the RRES Program. Earthlight Comments, Aug. 19, 2026, pp. 3-4. In particular, Earthlight disputes the EDCs' suggestion that MFAH projects are comparable to NRES or SCEF projects, stating that MFAH RRES projects would likely fall into the small or medium NRES size categories and would not be viable as SCEF projects. Id. Additionally, Earthlight highlights that MFAH RRES projects require the system owner to share a percentage of the tariff value (20% for individually metered, and 25% for master-metered buildings) with tenants, and are designed to benefit underserved ratepayers; a lower compensation rate for MFAH projects would directly reduce the billing credits afforded to such customers. Id. Finally, Earthlight states that requiring installers to utilize separate points of interconnection for each individual building would increase costs through additional interconnection applications, meters, and other electrical equipment, potentially making projects cost prohibitive. Id., pp. 3-4.

OCC supports the adoption of sizing or siting thresholds for MFAH systems that focus MFAH eligibility on systems located on or at the property they serve, and consideration of whether "an NRES-style methodology would better reflect the cost structure" of MFAH projects. OCC Comments, Aug. 19, 2026, p. 4. OCC suggests that compensating large-commercial scale systems at the Buy-All rate and income-eligible adder risks overcompensation as the rate-setting methodology is based on average residential costs. Id. At the same time, OCC does not support adoption of changes that foreclose solar access for low-income residents, and underscores that compensation levels should remain sufficient to support solar deployment for affordable housing properties. Id. Further, OCC urges the Authority to consider the extent to which large ground-mounted MFAH projects are actually delivering bill savings to low-income tenants, as required by the program, and to consider revisions to the program structure if benefits are not actually flowing to tenants. Id.

At this time, the Authority does not find it necessary to change the program rules regarding MFAH eligibility and compensation for the final year of the RRES Program. The program's current rules limit project sizing to the historical load of the applicable housing property, including allowable future electrification measures, or up to 9 kW AC per dwelling unit if historical usage is not available. Compliance, Jan. 22, 2026, Docket No. 25-08-02, Att. 1B, p. 53. Current rules also require that the eligible solar PV system be located at the eligible property. Id., p. 20. The Authority understands that the EDCs have received interest from potential projects that would be located at a separate

interconnection point from the existing building load, rather than at the existing interconnection points of the eligible building(s). Eversource Interrog. Resp. CAE-25. However, it is unclear whether this distinction is meaningful, if requiring separate interconnection points would likely increase project upfront costs without impacting the resulting project size or distribution of benefits.

The Authority also finds insufficient evidence to justify a distinct Buy-All rate setting methodology for MFAH RRES projects. The economics of MFAH projects and similarly sized commercial NRES projects are not directly comparable, as MFAH projects are required to share at least 20% of the tariff benefit with tenants, may have more complex building and electrical configurations, and involve coordination between multiple parties. Results of CGB's recent MFAH project installation procurement indicate that for projects larger than 100 kW AC, installed costs per watt are not substantially lower than average installed costs for the 1 to 4-unit RRES segment. Additionally, MFAH project data provided by the EDCs indicate that projects vary widely in size, from under 10 kW AC to over 100 kW AC. Eversource Interrog. Resp. CAE-25, Att. 1; UI Interrog. Resps. CAE-24 and CAE-25, Att. 1. Determining a separate Buy-All rate setting methodology that reflects the costs of the variable project types in the MFAH market is unlikely to be administratively feasible.

G. PROPOSED PROGRAM DOCUMENT CHANGES

The EDCs filed clean and redlined updates to the Program documents for review and approval, in accordance with Order No. 1 of the Year 5 Decision. Motion No. 7, July 31, 2026.

EOE identifies several broken links, numbering errors, and missing footnotes or references that should be corrected to avoid confusion and ensure participants have access to all necessary information. EOE Comments, Aug. 19, 2026, pp. 2-3. OCC similarly recommends that the EDCs conduct a thorough cleanup and consistency review of the redlined documents. OCC Comments, Aug. 19, 2026, p. 1. Additionally, EOE notes that in Attachment 8, data field number 6 should refer to income-eligible "application," not "qualification." Id.

OCC also suggests that the Program Manual should contain clear, affirmative language directing income-eligible customers to apply for the income-eligible adder to improve enrollment. OCC Comments, Aug. 19, 2026, pp. 1-2. Additionally, OCC argues that the Program Manual should contain a complete summary of all contractor compliance obligations, including requirements regarding marketing and training materials; currently, the manual only addresses contractor financial benefits compliance requirements. Id., p. 2.

Sunrun and Goodleap support most EDC changes that reflect CCWG recommendations, but disagree with the specific definition of Estimated Year One Production (kWh) added to the CDFs. Sunrun and Goodleap Comments, Aug. 19, 2026, p. 2. Specifically, Sunrun and Goodleap note that the proposed definition references the PowerClerk production estimate as the default method and treats a contractor-provided

production estimate as an alternative method requiring additional explanation. Id. Sunrun and Goodleap argue that this framing should be reversed, as the contractor-provided estimate, not the PowerClerk estimate, is the annual production value reflected in the system design and contract. Id. Additionally, Sunrun and Goodleap suggest that the Allowable Alternative Calculations box may require more space than is provided, depending on the number of variables that must be explained. Id., pp. 2-3.

The Authority directs the EDCs to check all links, numbering, and internal references in the program documents, including the specific apparent errors identified by EOE, before filing updated documents in compliance with Order No. 22 of this Decision. Additionally, Section IX of the Program Manual references contractor compliance requirements for marketing materials and training materials regarding sales and communications with potential customers; nevertheless, the Authority agrees with OCC that a more complete explanation of the requirements established in the Year 3 Decision would be beneficial for participating RRES contractors, and directs the EDCs to update the Program Manual accordingly. This section shall also include all new contractor requirements approved in Section D of this Decision.

In addition to incorporating the contractor compliance requirements authorized in Section D, the Authority directs the EDCs to adjust the definition of Estimated Year One Production (kWh) in the CDF as suggested by Sunrun and Goodleap. The Authority finds that the contractor-provided estimate, which matches what is provided to the customer in the installation contract and other materials, should be treated as the default production estimate. Additionally, per the direction in Section D.8, contractors will be required to provide the CDF contemporaneously with the contract rather than generating the CDF within PowerClerk, so the default annual production provided on the CDF should not be based on a PowerClerk calculation. The Authority also notes that contractors will be required to provide an explanation of the starting utility rate used, as well as the utility escalation rate and PV degradation rate, if different from the approved values; accordingly, the EDCs shall provide additional space in the Allowable Alternative Calculations fillable text box.

V. CONCLUSION AND ORDERS

A. CONCLUSION

In this Decision, the Authority explores and approves several changes to the RRES Program to better serve the Program Objectives and approves the RRES Program Tariff rates for project applications received in calendar year 2027.

Further, the Decision includes the Authority's rulings to Motion Nos. 4, 5, 6, 7, and 8 in the instant proceeding, and Motion No. 24 in Docket No. 25-08-02, Annual Residential Renewable Energy Solutions Program Review – Year 5.

B. EXISTING AND NEW ORDERS

For the following Orders, the Company shall file an electronic version through the Authority's website at www.ct.gov/pura. Submissions filed in compliance with the

Authority's Orders must be identified by all three of the following: Docket Number, Title and Order Number. Compliance with orders shall commence and continue as indicated in each specific Order or until the Company requests and the Authority approves that the Company's compliance is no longer required after a certain date. All Orders requiring Authority review and approval shall be submitted as a motion.

The below standing orders are a summation of prior orders related to the RRES Program that continue to apply. In some instances, the Authority has amended those standing orders with redline edits. The below new orders apply on a going forward basis.

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

1. Reference Interim Decision, Feb. 10, 2021, Docket No. 20-07-01, Order No. 4, p. 44; Interim Decision, Oct. 6, 2021, Docket No. 21-08-02, Order No. 8, p. 28: No later than [August 1], 2021, the EDCs shall develop and file for the Authority's review, modification, and approval a set of (1) Program Manual and guidelines and (2) other resources for residential utility customers and/or renewable energy contractors to explain the technical, administrative, and procedural requirements of the Residential Tariff program, including all cash out provisions. Such Program Manual, guidelines, and other resources shall strictly adhere to this Interim Decision, incorporating any direction provided herein. Any proposed rules and guidelines shall include a list of program eligibility requirements. The EDCs shall update all Program Manual, guidelines, and other resources by August 1 annually [until August 1, 2026] to reflect the most recent program information and Authority orders and/or rulings and file the aforementioned updated documents in the appropriate annual review docket (e.g., changes to be enacted in 2024 should be filed in Docket No. 23-08-02). Additionally, the EDCs shall review and update their meter wiring diagrams and guidelines as appropriate, but no less frequently than August 1 annually, and submit the revised documents in the appropriate Annual Review docket.

2. Reference Interim Decision, Feb. 10, 2021, Docket No. 20-07-01, Order No. 5, pp. 44-45: No later than [August 1], 2021, and annually thereafter [until August 1, 2026], each EDC shall file, in the annual Residential Tariff program review and rate setting proceeding for the Authority's review, modification, and approval a proposal for a Residential Tariff program application fee to cover the estimated administrative costs associated with processing applications. The EDCs shall provide detailed calculations and written descriptions to explain and to justify the proposed application fee. In the same filing, the EDCs shall file for the Authority's review, modification, and approval a proposed nominal administrative fee pursuant to Section III.A. for any change orders or re-designation changes subsequent to the initial project interconnection, so long as a robust rationale for the proposed fee and fee level is provided. The 2021 submission shall provide a copy of the language to be included in the customer disclosure form informing program participants of the fee.

3. Reference Interim Decision, Feb. 10, 2021, Docket No. 20-07-01, Order No. 15, p. 46: No later than November 1, 2021, the EDCs shall file with the Authority link to their respective Residential Tariff program webpages. Such webpages shall include all relevant information regarding the "buy-all" and netting Residential Tariffs for interested residential customers and renewable energy contractors. Such website shall be made public no later than January 1, 2022 and shall be updated as frequently as is practicable, unless otherwise directed herein, to reflect the most recent program information and Authority orders and/or rulings

4. Reference Interim Decision, Feb. 10, 2021, Docket No. 20-07-01, Order No. 19, p. 47: No later than January 1, 2023, each EDC shall have in place a customer education and information webpage that shall, at a minimum, include the average installed cost ($/W) and PPA or lease price ($/kWh) for all Residential Tariff applications accepted by the EDC over the preceding 6-month period, as well as current and historical retail rates for the customer to compare their pricing and savings in real-time. Such website shall be updated at least monthly and customers shall be required to electronically acknowledge that they have reviewed the material on the customer education and information webpage as part of Residential Tariff application process. On or before January 1, 2022, each EDC shall submit a cost estimate for the development of such a webpage. On or before August 1, 2022, each EDC shall file with the Authority a working draft of such webpage.

5. Reference Interim Decision, Feb. 10, 2021, Docket No. 20-07-01, Order No. 21, p. 47: No later than [August 1], 2022, each EDC shall publicly disclose the costs of setting up and maintaining the REC metering equipment, as well as the customer acquisition costs, on their respective Residential Tariff websites. Each EDC shall update the required information at least annually. No later than [August 1], 2022, and annually thereafter [until August 1, 2026], each EDC shall submit in the above-captioned proceeding and in the appropriate annual review docket (e.g., changes to be enacted in 2024 should be filed in Docket No. 23-08-02) the required REC metering cost information.

6. Reference Interim Decision, Feb. 10, 2021, Docket No. 20-07-01, Order No. 22, p. 47: No later than August 1, 2022, and annually thereafter [through the duration of the RRES Program], the EDCs shall jointly file, in the annual Residential Tariff program review and rate setting proceeding the Excel workbooks outlined in Section III.[C].6.a. The EDCs shall each use the same Excel workbook, including the same format and the exact same data fields, as each other. The EDCs shall follow all other direction provided in Section III.[C].6.a. [The Authority further directs the EDCs to include the following in each annual filing:
(1) any supplemental field data as indicated in CAE-1 and CAE-14 in Docket No. 23-08-02 and included in the EDCs' redacted filings;
(2) a list of all existing data fields collected in the RRES application;
(3) information on the application submission and approval date for each RRES project;

(4) both solar PV costs, and other costs (e.g., costs of associated electrical upgrades);
(5) the number and percentage of LIDR customers enrolled in the RRES Program, broken out by both LIDR tier and RRES tariff;
(6) the number of add-on Netting systems enrolled in the Program which are unable to support the addition of a non-bypassable charge;
(7) by each developer, the number and percentage of systems by type of housing (e.g., single family, 2-4 unit multifamily, or multifamily affordable housing);
(8) by each developer, the number and percentage of total approved RRES applications which are eligible for the low-income or Distressed Municipality adder(s);
(9) the housing type (e.g., single family, 2-4 unit multifamily, or multifamily affordable housing) and metering type (e.g., master-metered or individually metered) for each RRES project; and
(10) whether each RRES project received assistance through Solar for All. See, UI Interrog. Resp. CAE-14, Att. 4 Public; Eversource Compliance, Aug. 22, 2023, Att. 1. Last, the Authority also directs the EDCs to include a summary of the Program data on the RRES Program websites. This data can be provided in any reasonable fashion (e.g., attached file, web link, embedded data), and may be relocated to the PURA Data Dashboard when the dashboard is expanded to include Clean Energy Program data.]

7. Reference Decision, June 8, 2022, Docket No. 21-08-02, Order No. 4, p. 16: No later than August 1, 2022, and [quarterly] thereafter, PURA requests that the Agencies file as compliance in the appropriate RRES annual review docket (i.e., in Docket No. 22-08-02 on August 1, 2022, etc.) a list of housing facilities eligible under Tier I of the affordable housing definition approved in Section II.A of this Decision. [The EDCs shall post the most recent compliance with this order, along with contact information for each of the Agencies, on the RRES Program website by January 1, 2024, and quarterly thereafter.]

8. Reference Decision, June 8, 2022, Docket No. 21-08-02, Order No. 5, p. 16: No later than August 1, 2022, and annually thereafter, the EDCs shall file as compliance in the appropriate RRES annual review docket (i.e., in Docket No. 22-08-02 on August 1, 2022, etc.) a list of housing facilities eligible under Tier II of the affordable housing definition approved in Section II.A of this Decision.

9. Reference Decision, June 8, 2022, Docket No. 21-08-02, Order No. 6, p. 16: No later than August 1, 2022, and annually thereafter, PURA requests that the Agencies file as compliance in the appropriate RRES annual review docket (i.e., in Docket No. 22-08-02 on August 1, 2022, etc.) the DEEP and DOH contact information for a housing facility seeking to be defined as “affordable housing” that does not meet the Tier I or Tier II thresholds of the affordable housing definition approved in Section II.A of this Decision. [The EDCs shall post the most recent compliance with this order on the RRES Program website by January 1, 2024, and annually thereafter.]

10. Reference Decision, June 8, 2022, Docket No. 21-08-02, Order No. 9, p. 17: No later than August 1, 2023, and annually thereafter, the EDCs shall file as compliance documentation of the distribution of the incentive adders to validate that the required percentage of the benefit was received by the tenants in multifamily affordable houses in the previous year (e.g., calendar year 2022 for the August 1, 2023 filing), for both the cases of on-bill credits for individually metered units and annual checks or other approved distribution methodology for those multifamily homes where units are not individually metered.

11. Reference Year 2 Decision, Order No. 12, p. 35: On a [quarterly basis beginning on January 1, 2024] through [the duration of the RRES Program], the EDCs shall provide updates to Docket No. 21-08-02 Response to Interrogatory CAE-8. Specifically, the Authority adapts the ruling in Docket No. 21-08-02 to Motion No. 26 dated March 22, 2022, which directed the EDCs to submit as a compliance filing an update to Interrogatory CAE-8 ~~on or before the 15th of every month through January 1, 2023 (i.e., the final filing would have been made on December 15, 2022), to instead direct the compliance filings to continue monthly through January 1, 2024~~. Such filings shall be made in [the annual review proceeding (i.e., in 2024, Docket No. 24-08-02)] and should also include tariff type and incentive adder status information. [Last, beginning by July 1, 2024, the quarterly filings shall include:
(1) the total number of low-income customers and customers located in Distressed Municipalities, and associated project capacity, which do not receive either adder, in addition to the existing breakouts for customers enrolled in the low-income and Distressed Municipality adders;
(2) the number and associated project capacity of customers who reside in environmental justice census block groups, broken out by customers that qualify for the low-income and Distressed Municipality adders and those that do not; and
(3) the number and associated project capacity of RRES customers who qualify for the Federal Justice 40 disadvantaged communities definition.]

12. Reference Year 2 Decision, Order No. 15, p. 35: No later than January 1, 2023, the EDCs shall update any clean energy and hardship program webpages where dual enrollment in any clean energy programs is adversely impacted or otherwise prohibited. Specifically, Eversource shall update at least their RRES Program and New Start webpages with a disclaimer alerting customers that, until such time as a proposal to enable concurrent participation in the RRES Program and the New Start Program is submitted by Eversource and approved by the Authority, existing New Start Program participants are unable to continue to participate in New Start once enrolled in the RRES Program. Moreover, moving forward, the Authority requires Eversource and UI to provide such disclaimer(s) on the appropriate clean energy program website for any instances where hardship program enrollment is jeopardized or negatively impacted by enrollment in solar programs, or vice versa. Each disclaimer should include an explanation of why dual enrollment is adversely impacted or prohibited. Further, the EDCs shall file a copy of the disclaimer(s) as

compliance and provide links to the online locations where the disclaimer(s) is/are located.

13. Reference Year 2 Decision, Order No. 17, p. 36: No later than May 1, 2023, and quarterly thereafter for the remainder of the RRES Program, the EDCs shall submit information for the prior quarter (e.g., January 1, 2023 through March 31, 2023 for the May 1, 2023 filing) on the following items related to RRES Program applications:
(1) the length of time from application to submission to tariff review approval;
(2) the length of time from tariff review approval to interconnection contingent approval;
(3) the length of time to receive the work order number needed to apply for permits from cities and towns;
(4) the length of time to process payments when applicable;
(5) the length of time for any applicable witness tests;
(6) the number of days between when the utility is notified of a completed inspection to meter installation; and,
(6) the length of time for final issuance of the permission to operate.

The RRES APWG may recommend additions to this list in their final report filed on December 14, 2022. Such filings shall be submitted in the relevant RRES Program review docket (e.g., any updates related to Year 2 of the RRES Program shall be disclosed in this proceeding, Docket No. 22-08-02).

14. Reference Year 2 Decision, Order No. 22, p. 37: Through the end of the RRES Program, the EDCs shall follow the guidance provided in Section IV.N of this Decision when making administrative changes to the RRES Program without prior PURA approval. Such changes shall be clearly documented, explained, and justified in a compliance filing submitted at least ten (10) business days prior to such changes taking effect in the relevant RRES Program review docket (e.g., any changes related to Year 2 of the RRES Program shall be disclosed in this proceeding, Docket No. 22-08-02). Justification must include a clear articulation of how each Program Objective may or may not be impacted and how the requested change would serve to further the Program Objectives overall.

15. Reference Decision, Feb. 8, 2023, Docket No. 22-08-02, Order No. 26, p. 17: As required, the Authority directs the EDCs to identify any required NEPOOL waivers to allow the program to continue without the utility-owned meter socket requirement through June 2024, and to request the requisite authorization from PURA.

16. Reference Decision, Nov. 1, 2023, Docket No. 23-08-02, Order No. 24, p. 64: No later than February 1, 2024, and annually thereafter [through the duration of the RRES Program], the EDCs shall hold at least one webinar with solar developers to inform them of the underserved adder eligibility criteria, in addition to other Program requirements and information. Further, during the webinar to be held by

February 1, 2024, the EDCs shall update Program installers on the implementation of LIDR and provide information and examples of how installers can identify LIDR-enrolled customers, to ensure that LIDR customers are receiving bill savings from participation in the RRES Program. [The EDCs shall also include an overview of the contractor requirements regarding standardized inputs, allowable methodologies, and timing of disclosure form presentation to customers.] At least 30 days' notice shall be provided to Program stakeholders prior to the date of the webinar on the Program website. As compliance, the EDCs shall file the date, time, and location of the webinar with the Authority in the applicable annual review proceeding at least 21 days prior to the webinar.

17. Reference Decision, Nov. 1, 2023, Docket No. 23-08-02, Order No. 33, p. 66: No later than June 1, 2024, and April 1 and annually thereafter [through the duration of the RRES Program, inclusive of April 1, 2028], all renewable energy contractors participating in the RRES Program shall file in the reopener to the annual Program Review docket for contractor education and enforcement (e.g., Docket No. 23-08-02RE01 for 2024, etc.), their marketing scripts and training materials generated for or provided to anyone engaging with a customer. Last, the Authority clarifies that the collection of marketing materials shall be administered and enforced by EOE.

18. Reference Decision, Nov. 1, 2023, Docket No. 23-08-02, Order No. 34, p. 67: No later than June 1, 2024, and April 1 annually thereafter [through the duration of the RRES Program, inclusive of April 1, 2028], all Program developers shall file in the reopener to the annual Program review docket for contractor education and enforcement (e.g., Docket No. 23-08-02RE01 for the 2024 filing, etc.), a Financial Benefits Compliance, in accordance with Section IV.D. Specifically, the Authority directs each developer participating in the RRES Program to annually file with the Authority the following for all RRES projects deployed in the previous calendar year:

(1) All customer disclosure forms;

(2) An unlocked Excel file summarizing key information from the customer disclosure forms, as well as other information provided to customers such as contracts and promotional materials, for each project as detailed below (Financial Benefits Summary Sheet); and

(3) A narrative explanation of any calculation methodologies included in the Financial Benefits Summary Sheet (Sheet Narrative).

The Financial Benefits Summary Sheet shall include one row each for every project deployed by the developer under the RRES Program in the previous calendar year. For each project, the following information shall be provided (i.e., each of the following should be a column in the Financial Benefits Summary Sheet):

(1) site address;

(2) utility account number associated with the project;

(3) annual contract rate increase amount;

(4) estimated year one production (kWh) as a percentage of estimated annual utility customer usage (kWh);

(5) estimated year one customer net savings;
(6) starting utility rate used to estimate net year one savings;
(7) estimated net savings over the RRES tariff term (i.e., 20 years) if provided by the developer to customers in a contract or promotional materials, or if it can be easily extrapolated from the customer disclosure data; and
(8) utility rate used to estimate net savings over the RRES tariff term (i.e., 20 years) if provided by the developer to customers in a contract or promotional materials, or if it can be easily extrapolated from the customer disclosure data.

The Sheet Narrative may be a simple summary document (e.g., as brief as a couple of pages) outlining the methodology used to calculate the above required information to be included in the Financial Benefits Summary Sheet, as applicable, along with a general list of the documents needed for such calculations (e.g., a customer's electric bill and sales contract are needed to verify the methodology for the fourth requirement, etc.). Last, the Authority clarifies that the collection of financial benefit documentation shall be administered and enforced by EOE. EOE may audit a contractor's Financial Benefits Summary Sheet and Sheet Narrative and can request additional documentation or evidence as needed to verify a contractor's Financial Benefits Summary Sheet calculations, particularly for low-income customers.

19. Reference Decision, Nov. 1, 2023, Docket No. 23-08-02, Order No. 36, p. 68: No later than October 1, 2024, and annually by August 1 thereafter [through the duration of the RRES Program], EOE shall complete its audit of the Financial Benefits Compliance filings and a sampling of RRES developer marketing materials and file any findings with the Authority as directed in Section IV.D.3. of this Decision following the "four strike" system authorized in the Residential Tariff Decision as necessary.

20. Reference Decision, Oct. 16, 2024, Docket No. 24-08-02, Order No. 27, p. 33: Upon the Authority's approval of the March 31, 2025 Order No. 26 filing, the EDCs shall begin reviewing any requests for the approval of a specific model of MSA in the EDCs' service area. Within 90 business days of receiving a request for approval of a specific MSA model for installation in the EDCs' service area, the EDCs shall review and approve or disapprove the request. Upon approving an MSA model, the EDCs shall post the decision publicly on their webpages and update the relevant electric service guidelines. If an MSA model is disapproved, the EDCs shall provide an explanation of the reason(s) to the requesting vendor.

21. Reference Decision, Dec. 17, 2025, Docket No. 25-08-02, Order No. 24: No later than January 15, 2026, and annually thereafter in the most recent RRES annual review proceeding [through the duration of the RRES Program], the Authority requests that the MFH WG file a rent roll template in unlocked Excel format containing fields for the property address, number of units, rent for each unit, and

number of bedrooms in each unit for the property requesting approval. The template shall also include easily referenced rent limits affordable to households with income at or below 80% AMI for each unit size, based on the most recent HUD published data.

2. New Orders

22. No later than December 1, 2026, the EDCs shall file as compliance updated RRES Program documents, including the Program Manual, RRES Metering Diagrams, Frequently Asked Question document, and Fact Sheet, incorporating all the approved modifications authorized in this Decision. Such filing shall include both a clean and a redlined version of all RRES Program documents.

23. No later than December 1, 2026, UI shall update its metering diagrams and guidelines to require that no load (except for parasitic load utilized to operate the coupled solar and storage system) is connected behind the production meter for DC-coupled solar and storage systems, and file the updated diagrams for Authority review and approval. Additionally, UI shall meet with industry stakeholders to discuss the updated metering diagrams and incorporate stakeholder feedback prior to filing with the Authority.

24. No later than December 1, 2026, the EDCs shall notify participating RRES Program applicants of the updated contractor requirements through an email notification, PowerClerk banner, and the EDCs' RRES program webpages, and file compliance in the instant proceeding once complete.

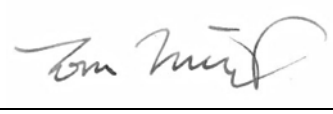
25. No later than January 1, 2027, the EDCs shall complete the necessary updates to the RRES PowerClerk application to incorporate the direction in Section D, Contractor Compliance, and file compliance in the instant proceeding once complete.

26. No later than January 1, 2027, all Program developers shall begin adhering to the compliance requirements specified in this decision. Specifically, Program developers shall utilize the allowable methods for determining customers' annual electricity usage, estimated year one net savings, estimated multi-year net savings, and starting average utility rate; utilize the standardized values for utility escalation rate and PV degradation rate, or an approved alternative; and present the customer disclosure form to customers immediately prior to and contemporaneously with the solar installation contract.

27. Effective immediately, UI shall resume reporting and selling RECs from RRES solar PV systems paired with DC-coupled storage. UI shall file compliance in the instant proceeding once REC sales have resumed.

DOCKET NO. 26-08-02 **ANNUAL RESIDENTIAL RENEWABLE ENERGY SOLUTIONS PROGRAM REVIEW AND RATE SETTING – YEAR 6**

This decision is adopted by the following commissioners:



Thomas H. Wiehl



David Arconti, Jr.



Janice A. Beecher



Holly H. Cheeseman



Everett Smith, III

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

October 28, 2026
Date

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