



July 25, 2025

Samantha Meserve, Director of the Renewable and Alternative Energy Division  
Grace Fletcher, SMART Program Manager  
Massachusetts Department of Energy Resources  
100 Cambridge Street, 9<sup>th</sup> Floor  
Boston, Massachusetts 02114

RE: Comments from the Solar Energy Business Association of New England (SEBANE) to the  
Massachusetts Department of Energy Resources (DOER) re: SMART 3.0 Emergency  
Regulations

Dear Ms. Meserve and Ms. Fletcher,

The Solar Energy Business Association of New England (SEBANE) is pleased to submit our written comments regarding the SMART 3.0 emergency regulations. SEBANE is a nonprofit trade association representing over 80 member companies across the solar value chain, including residential installers, commercial and community solar developers, component manufacturers, financiers, and service providers.

Our mission is to protect and promote the New England solar industry through informed policy advocacy, coalition building, and stakeholder education.

First, we want to thank the Department of Energy Resources, and in particular you, Director Meserve, for your leadership and thoughtful engagement with stakeholders throughout the SMART 3.0 process. We sincerely appreciate the extended stakeholder conversations and the willingness to connect via correspondence and in person to talk through questions and issues that have arisen. The emergency regulations reflect significant improvement from previous versions of the SMART program, especially focusing on the establishment of mechanisms to allow for responsiveness to rapidly changing market conditions, which we believe is critically necessary for programmatic success. We also recognize and appreciate the Commonwealth's commitment to making Massachusetts a national leader on climate action. That commitment is not just noticed—it's deeply valued by the solar and storage companies doing business here, many of whom are SEBANE members who have made long-term investments in helping realize the vision Governor Healey has laid out.

We believe SMART 3.0 can and should be a cornerstone of that vision. That's why SEBANE and our members have dedicated much of our time over the past year to reviewing the evolving program, offering detailed feedback, and providing real-world examples of where the proposed,



and now emergency regulations, will work—and where adjustments are needed to align with how solar markets and business models actually function.

To begin, SEBANE believes it is imperative for DOER to understand the current federal environment regarding clean energy development and the significant impacts from the July 4, 2025 passage of the budget reconciliation package in Washington, DC. As you know, this bill makes significant, immediate changes to clean energy tax credits and quickly repeals the 25D residential solar credit as well as the 48E investment tax credit (ITC) utilized for commercial solar systems. Developers have only until July 4, 2026 to safe harbor projects to qualify for the ITC (unless projects are placed into service by the end of 2027), though many developers are looking to safe harbor projects by the end of this year given the vague restrictions regarding foreign components that will begin on January 1, 2026. For the Commonwealth to advance its clean energy and climate goals, it is critical for DOER to consider this context and commit to incentivizing as much solar as possible in 2025 and 2026 as the industry will face unprecedented headwinds in years to come. In many cases, projects will simply not pencil. If the Commonwealth wishes to deploy clean electrons to the grid at a time of rapidly rising demand, we strongly urge DOER to increase and/or eliminate program capacity caps for both 2025 and 2026. We also encourage DOER to consider how the requirement for no changes more than 10% year over year may need to change to ensure that such drastic financial changes due to the loss of tax credits can be accommodated (and that changes in federal and state incentives should be explicitly included in the consideration of rate development). Given the passage of the budget reconciliation package, existing survey data may no longer accurately reflect project finance. We thank the DOER in advance for its diligent response to federal uncertainty and willingness to consider mechanisms that respond to market realities to ensure solar energy can still be viably deployed.

We would also like to offer our support in the dissemination of the survey that determines annual rates given the critical importance of its accuracy. We would be happy to partner with DOER to ensure the survey makes it to the appropriate contacts at solar development firms across the state and/or collect and anonymize data if that would assist in ensuring developers feel comfortable sharing proprietary data. Regardless of tactic, we would love to partner with DOER to ensure the survey receives adequate accurate responses given that its use in rate development has a critical impact on our industry.

Additionally, we would like to take the opportunity to share specific feedback from across our membership for your consideration. As you finalize these regulations, we ask you to take the industry's perspective into consideration and address the following issues:

## **Issue 1: Incentive Structure Discourages Larger Rooftop Systems**

### **Why this is a problem:**

The current SMART rate structure unintentionally incentivizes developers to downsize rooftop solar systems to qualify for higher-tier rates. This undermines the goal of maximizing solar generation on available rooftops.

### **Example:**

Developers will often design a 375 kW DC system instead of a 475 kW DC system in order to qualify for a higher incentive rate (25 kW – 250 kW AC), even if the larger system would better serve the building's energy needs and reduce emissions more effectively.

### **Proposed Solution:**

Adopt a blended rate structure that allows a portion of the system to receive the higher-tier rate, with the remainder receiving the lower-tier rate. This would remove the disincentive to build larger systems while maintaining tiered pricing integrity.

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## **Issue 2: Residential BTM Systems should be offered a higher SMART rate**

### **Why this is a problem:**

Homeowners who install behind-the-meter (BTM) systems under the designated SMART rate of \$.03/kWh will see less economic benefit than if they were to leverage Class 1 RECs instead.

### **Example:**

The cost of the SMART meter, the labor to install the meter, and the administrative effort to enroll all reduce the economic benefit of the solar system to the homeowner (and it's worth noting that the utility actually takes the meter back after 20 years).

### **Proposed Solution:**

Allow higher incentive rates (\$0.05–\$0.06/kWh) for BTM residential systems owned by the homeowner, or, eliminate the requirement that homeowners must enroll in SMART to obtain net metering. This would expand access, increase demand and support equitable solar adoption.

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## **Issue 3: The Value of Energy Calculation for Commercial BTM Systems Results in Lower-Than-Expected Incentives**

### **Why this is a problem:**

Commercial BTM systems using the current Value of Energy (VoE) calculation often receive significantly lower effective incentive rates due to net metering haircuts, even when systems are well-matched to on-site load.

**Example:**

A commercial system that matches 100% of its load may still export 20%–40% of its generation, receiving a bill credit for only 60% of avoided cost for each exported kWh. This reduces the average incentive rate well below the published rate.

**Proposed Solution:**

Revise the VoE calculation to reduce the penalty for modest export. One option would be to offer a slightly higher incentive rate for BTM commercial systems that meet a minimum on-site consumption threshold.

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**Issue 4: CSS Should Include a Low-Income Allocation Option****Why this is a problem:**

The rules for the new Community Shared Solar (CSS) adder make CSS management more complex, allowing modest attrition to threaten the system's SMART compensation. This structure creates major implementation challenges. Massachusetts prevents utility shut-off for many low-income customers during much of the year, which limits the incentive to pay utility bills — including community solar charges. As a result, nonpayment rates are high, subscriber churn is difficult to manage, and developers bear the full repayment risk. With limited tools to enforce payment, many projects are choosing to bypass the Community Shared adder entirely and enroll under the base feed-in tariff.

**Example:**

If a project is launched with 40% low income offtake, and then experiences even modest attrition, it will run afoul of program rules.

**Proposed Solution:**

Replace the 40% LMI at 20% discount requirement with a simpler and more effective alternative. For example, allow CSS projects to allocate 10% of production to LI customers at no cost, with the remaining 90% sold to non-LI customers at a minimum 10% discount. This balances equity goals with project economics.

Or alternatively, require that 10% of project capacity be allocated to Low Income Customers at a 100% discount.

- This broadens the eligible pool of LMI subscribers by eliminating the need for customer payments — reducing reliance on credit checks, billing logistics, and ongoing collections. This makes participation possible for households that would otherwise be excluded.
- This reduces administrative and financial risk for developers by removing repayment obligations from subscribers entirely.

- This alternative delivers greater total LMI savings: 40% of output at a 20% discount = 8% effective project-wide discount. 10% of output at a 100% discount = 10% effective discount.

If this is too ambitious for emergency regulations, consider it for future rulemaking.

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### **Issue 5: Mandating Capacity Allocations for Mid-Sized Standalone Projects Creates Barriers**

#### **Why this is a problem:**

Standalone projects between 25 kW and 250 kW face high fixed costs and limited economies of scale. Subjecting them to capacity allocations adds delays and uncertainty, discouraging development.

#### **Example:**

A 100 kW project on a school or small business may be delayed for months waiting for capacity allocation, increasing soft costs and risking project cancellation.

#### **Proposed Solution:**

Exempt standalone projects between 25 kW and 250 kW from capacity allocations to streamline deployment and support solar growth in the built environment.

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### **Issue 6: Canopy Adder Should Apply to Sub-25kW Projects**

#### **Why this is a problem:**

Small-scale canopy projects (e.g., carports at homes or small businesses) are excluded from the canopy adder, despite their potential to expand solar in the built environment.

#### **Example:**

A homeowner with a shaded roof could install a 10 kW carport system, but without the canopy adder, the economics are unfavorable.

#### **Proposed Solution:**

Extend the canopy adder to sub-25kW projects to unlock this underutilized segment and support equitable access to solar.

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## **Issue 7: Canopy Adder Should Apply to Raised Racking on Commercial Rooftops**

### **Why this is a problem:**

Raised racking systems can dramatically increase solar capacity on commercial rooftops, but they are not currently eligible for the canopy adder.

### **Example:**

A flat-roofed apartment building could install 200%-300% more solar with raised racking by allowing panels over the entire surface area, but the added cost makes it unfeasible without additional incentives.

### **Proposed Solution:**

Allow raised racking systems with a lower module drip edge of no less than 6 feet on commercial rooftops to be eligible for the canopy adder to encourage higher-density solar installations and maximize solar in the built environment.

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## **Issue 8: Energy Storage Requirement – Rooftop STGUs are Exempt from Energy Storage Co-Location, but Canopy Systems Are Not**

### **Why this is a problem:**

Canopies often have site constraints similar to rooftop systems, especially in dense urban areas. Requiring storage adds complexity and cost.

### **Example:**

For example, a carport system in a tight urban lot can't accommodate a battery, making the project financially unworkable.

### **Proposed Solution:**

Extend the exemption from the storage requirement to Canopy STGUs as defined in 225 CMR 28.02.

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## **Issue 9: Community Shared Solar – Discount Requirements**

- **Issue 9a:** Minimum discount percentages are tied to the Net Metered “Value of Energy” (VoE), even though most projects will use AOBCs.
  - **Why It's a Problem:** AOBC bill credits are significantly lower in value than Net Metering credits, as AOBCs are based only on the supply rate. Applying the discount to VoE inflates the real-dollar value of required savings, pushing effective discounts well beyond 10% or 20%.

- **Example:** A 20% discount on VoE is much more than a 20% discount in actual dollars on a bill using AOBC credits.
  - **Proposed Solution:** Tie minimum discount thresholds to actual dollar value of credits received by subscribers each month, not per-kWh VoE calculations. This will greatly reduce confusion for the customer.
  - **Issue 9b:** Commercial subscribers are required to receive a minimum 10% discount.
    - **Why It's a Problem:** Commercial subscribers do not need guaranteed savings to justify participation. The minimum discount requirement may be unnecessary and restrictive.
    - **Example:** Commercial subscribers, especially large anchor offtakers, don't need discounts to participate, but the rule forces developers to offer them.
    - **Proposed Solution:** Limit the 10% minimum discount requirement to non-LMI residential subscribers only.
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## **Issue 10: Agrivoltaics – Maximum DC Capacity for Dual-Use Agricultural STGUs (ASTGUs)**

### **Why It's a Problem:**

The cap as outlined in the emergency regulations is arbitrary and may discourage larger agrivoltaics projects that maximize land productivity for both farming and clean energy.

### **Example:**

A farm could host a 10,000 kW DC system that supports both crop production and clean energy but is blocked by the cap.

### **Proposed Solution:**

Raise the 7,500 kW DC cap to a minimum of 10,000 kW DC (to match the 5,000 kW AC maximum of SMART), or remove the cap entirely, to reflect actual grid and land-use constraints rather than an arbitrary limit.

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## **Issue 11: BTM Incentives are Less than FTM Due to VOE Subtraction from SMART Rates**

### **Why It's a Problem:**

The current VOE calculation yields a significantly higher VOE than the customer's actual VOE replaced by solar production and discourages the development of BTM solar. Business owners whose first preference is to save energy find themselves asked to lease their roof to a 3<sup>rd</sup> party.



Encouraging the development of BTM solar will allow the SMART budget to support more solar MW's of power generation.

**Example:**

The current VOE calculation is higher than a solar customer's actual VOE due to three factors:

1. Uses a 3-year average which includes Basic Service price spikes from past winters
2. The current VOE calculation takes the average of the Fixed Basic Service rate for residential and small commercial customers and the variable (monthly) rate for large commercial customers.
  - a. Basic Service rates are higher in the winter when solar production is much less
  - b. Basic Service rates are lower in the summer when solar production is much higher
  - c. ISO-NE Average BTM solar data for Massachusetts for 2023 and 2024 shows 12% of annual production occurs in December through February and 36% of annual production in May through July
  - d. If VOE was weighted based on solar production, VOE would be 2-3 cents less per kWh
3. Implementation within the past year of the Massachusetts Climate Acts of 2021 and 2022 has changed the net metering rules. A "Cap Exempt Facility Servicing On-Site Load" designation as defined in 220 CMR 18.02 *Definitions* is now available to all non-public BTM customers and provides Net Metering Credits calculated as 60% of the excess kWh in the month times the sum of the Basic Service Rate, Distribution Charge, Transmission Charge and Transition Charge. Any excess solar generation above the building annual usage is credited at the utility's avoided cost rate (ACR) for roughly 4 cents per kWh (MA 2024 average), so there is a dis-incentive to oversize the PV system beyond the building's annual usage.

**Proposed Solution:**

As a result, we suggest two changes to correct this imbalance. First, add a new Net Metering category and calculations for facilities net metering as a "Cap Exempt Facility Servicing On-Site Load." This category would use similar assumptions as the AOBC/QF VOE, where 35% of the annual usage was assumed to be excess in a given month. Second, use a three-year average of the March-November values of the Basic Service Rate for each tariff as a value weighted better to the Value of Energy that is replaced by solar generation. Given the complexity of this change, we have offered an appendix that outlines how such changes could be codified into the emergency regulations, which we have attached at the end of our comments.

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Lastly, it's also important to address a few more granular details that carry considerable weight. Again, we thank DOER for its consideration:

- Residential Third-Party Owned systems <25 kW in size are required to have a savings equivalent of 10% or greater and have a minimum escalator of 3%. It is important to remember that there are different types of lease models and while this may be intended for PPA models, it does not make sense for a system in which the customer is getting all of the energy value. It does not make sense to require a discount for an equipment lease that has fixed costs. (28.07(5)(a))
- STGUs are ineligible for SMART if the footprint overlaps with a wetland resource area. We understand there are concerns about this determination overall, and we seek to add an additional point: if the wetland resource area has already been developed (i.e. a building or a parking lot overlaps), a building-mounted or canopy STGU should not be prohibited. (28.08(1)(a))
- Systems 25kW or less are required to provide additional documentation for their SOQ, including a customer utility bill. There should be an exception for a utility bill if the project is a new construction, as there would be no utility history (28.06(1)(b)3)
- There appears to be a typo in the section regarding additional documentation required in 28.06(d)-- it says that STGU of 1,000 kW or less shall attest to its status under PURPA, however PURPA is only applicable to projects greater than 1,000 kW. (28.06(1)(d))
- SOQ applications are subject to review by DOER, the Solar Program Administrator and the Distribution Company, and each are allowed 30 business days to process the application. Ultimately, that means this could be a 4.5-month timeline, which we believe is too lengthy. We recommend limiting the total time for all parties to 45 business days during the 10-day open application period or 30 business days during the rolling enrollment period. Additionally, given an executed ISA is required for all projects greater than 25 kW, there should be no need for utilities to participate in this review timeline. (28.06(1)(e))

Understanding the rapidly rising demand for electricity and the fact that solar energy is the fastest deployed form of energy to the grid with the lowest levelized costs, we thank DOER for stepping up to offer a new iteration of SMART to meet the Commonwealth's ambitious but necessary climate and energy goals. We appreciate DOER's willingness to listen to the industry's concerns to ensure the program is as successful and implementable as possible. We are happy to answer any questions and provide any further data upon request. Thank you for your consideration.

Sincerely,

Nick d'Arbeloff, President

Lindsay Bourgoine, Vice President, Policy

Trish Fields, Executive Director

## Appendix: Proposed Changes to Address Issue 11

### 28.14 Calculation of Incentive Payments for STGUs

(2) Calculation of Incentive Payments for Behind-the-Meter STGUs greater than 25 kW. Payments provided to the Owner of a Behind-the-Meter STGU by a Distribution Company for RPS Class I Renewable Generation Attributes and Environmental Attributes will be fixed at the point in time that a STGU receives its Final Statement of Qualification for the duration that the STGU is eligible under 225 CMR 28.00 and will be equal to the total of the STGU's Base Compensation Rate plus any Compensation Rate Adders, minus the value of energy, multiplied by the total kWh generated by the STGU in the Distribution Company billing period.

$$\begin{aligned} & \textit{Behind-the-Meter Solar Incentive Payment} \\ &= [(Base Compensation Rate + Compensation Rate Adders) \\ &\quad - \textit{value of energy}] * \textit{total kWh generated} \end{aligned}$$

The methodology for calculating the value of the energy for a Behind-the-Meter STGU is dependent on whether the Generation Unit is qualified as a Net-Metered Generation Unit **other than a Cap Exempt Facility Servicing On-Site Load, a Cap Exempt Facility Servicing On-Site Load Net-Metered Generation Unit**, an Alternative On-Bill Credit Generation Unit, or a Non-Net Metering Generation Unit, and will be determined as follows:

(a) Value of Energy for Net-Metered Generation Units **other than a Cap Exempt Facility Servicing On-Site Load**. The VOE shall be equal to the sum of the Owner's current distribution kWh charge, current transmission kWh charge, current transition kWh charge, and the average of the basic service kWh charge from **March to November** in the prior three calendar years.

$$\begin{aligned} & \textit{Net Metered value of energy} \\ &= (\textit{distribution kWh charge} + \textit{transmission kWh charge} \\ &\quad + \textit{transition kWh charge} \\ &\quad + \textit{three year average from March to November of basic service kWh charge}) \end{aligned}$$

(b) VOE for Alternative On-Bill Credit Generation Units and Non-Net Metered Generation Units. The VOE shall be equal to sixty five percent (0.65) of the sum total of the average of the basic service kWh charge **from March to November** in the prior three calendar years, current distribution kWh charge, current transmission kWh charge, and current transition kWh charge, plus thirty five percent (0.35) of the average of the basic service kWh charge **from March to November** in the prior three calendar years, as of the date of the STGU's preliminary Statement of Qualification.

$$\begin{aligned} & \textit{Alternative On Bill Credit and Non Net Metered value of energy} \\ &= [0.65(\textit{three year average from March to November of basic service kWh charge} \\ &\quad + \textit{distribution kWh charge} + \textit{transmission kWh charge} + \textit{transition kWh charge}) \\ &\quad + 0.35(\textit{three year average from March to November of basic service kWh charge})] \end{aligned}$$

**(c) VOE for Cap Exempt Facilities Servicing On-Site Load Net-Metered Generation Units.**



The VOE shall be equal to sixty five percent (0.65) of the sum total of the average of the basic service kWh charge from March to November in the prior three calendar years, current distribution kWh charge, current transmission kWh charge, and current transition kWh charge, plus thirty five percent (0.35) times 60 percent (0.60) of the sum total of the basic service kWh charge from March to November in the prior three calendar years, current distribution kWh charge, current transmission kWh charge, and current transition kWh charge, as of the date of the STGU's preliminary Statement of Qualification.

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Cap Exempt Facilities Servicing On-Site Load *value of energy*  
= [0.65(three year average from March to November of basic service kWh charge  
+ distribution kWh charge + transmission kWh charge + transition kWh charge)]  
+ [0.35\*0.60(three year average from March to November of basic service kWh  
charge  
+ distribution kWh charge + transmission kWh charge  
+ transition kWh charge)]