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TO: Sustainable Energy Advantage (SEA) on behalf of Rhode Island Office of Energy Resources (OER) and the Distributed Generation Board (DG Board)

FROM: Rhode Island Energy

DATE: September 15, 2023

SUBJ: Response to Request for Comments on 1st Draft of Rhode Island Renewable Energy Growth (REG) Ceiling Prices for Projects Less Than or Equal To 5 MW

Rhode Island Energy respectfully submits the following comments in response to the first draft of ceiling prices for projects less than or equal to 5 MW in the Renewable Energy Growth program. Rhode Island Energy is dedicated to providing safe, reliable, affordable, and sustainable energy to our customers. Encouraging development of renewable energy resources and the resulting clean electricity is a cornerstone of our mission. We consider the Renewable Energy Growth program to be a preferable compensation model for renewable electricity, when compared to other existing policies such as net metering, because of the data-driven approach to developing ceiling prices and the defined tariff term. Together, these program design elements result in a program that encourages renewable energy development at least cost for our customers. As such, Rhode Island Energy reviews these first draft ceiling prices with the dual objective of (i) using our expertise to be a productive partner in advancing Rhode Island's climate and clean energy mandates and (ii) vetting program costs on behalf of our customers. We provide general observations followed by specific comments in response to the three prompts provided in the Request for Comments.

General Observations

Overall enrollments in the Renewable Energy Growth program have been relatively low in recent program years. However, we strongly caution against considering enrollment in Renewable Energy Growth in isolation; one must consider the full context of compensation alternatives available to developers, including both compensation rates and program design elements. One potential erroneous conclusion is that ceiling prices are lower than they need to be to attract projects. This conclusion is erroneous because it fails to compare ceiling prices to the alternative net metering compensation value, which is arguably greater for many projects. Furthermore, we urge the DG Board and OER to prevent any artificial upward pressure on ceiling prices that is not directly supported by data, in alignment with the intent of the Renewable Energy Growth statute.

In considering program design, the legislature has insightfully allowed for ceiling prices to be developed for multiple years at a time – this program design change allows for improved predictability for developers and their financiers (more thoughts on this below). Despite this change, developers still show a revealed preference for net metering, especially for non-solar resources. Rhode Island Energy is eagerly open to identifying other program design modifications that, while consistent with statute, not only remove barriers to enrollment in Renewable Energy Growth but also make the program design of Renewable Energy Growth more palatable than compensation alternatives that are more costly for customers writ large. We invite ideas from developers, stakeholders, program participants and non-participants alike – please email Carrie Gill at cagill@rienergy.com and thanks in advance for helping to make Renewable Energy Growth a stronger program.

Rhode Island Energy observes that the first draft of ceiling prices for renewable energy classes less than or equal to 5 MW are substantially (on the order of 30%) higher than previous years. In addition to some specific technical comments and questions below, we ask that OER and the DG Board describe the main drivers of these cost increases in order to open policy discussion about how to mitigate and/or reduce those cost pressures in a sustainable, long-term manner. Increasing ceiling prices to account for those cost pressures is a short-term, unsustainable solution that results in higher bills for customers and fails to resolve root issues prevalent across all renewable energy development.

Finally, we acknowledge the decision at hand for the term and design of ceiling prices. The first draft of ceiling prices suggests that prices may change year-over-year and that the decision on whether to have a two-year or three-year term will not be made until ceiling prices are final. Rhode Island Energy observes several principles that OER and the DG Board may consider when making this decision:

1. One objective is to avoid opportunities to game enrollment that would result in higher-then-necessary program costs. If ceiling prices increase year-over-year and there is not a likely cap imposed on open enrollments (such as because of low class MW allocation or low demand), then an opportunity is created whereby developers may defer enrollment in the first year to achieve a higher ceiling price in a subsequent year. Although the first draft of ceiling prices for these classes have decreasing ceiling prices (two exclusions being Wind and Anaerobic Digestion), year-over-year, this objective may lead to a structural preference for ceiling prices that are constant year-over-year.
2. One objective is to appropriately compensate renewable energy projects given current macroeconomic conditions. While this objective may contrast with the first objective above, there may be some exogenous factors that could result in the adjustment of the ceiling price from year-to-year that mitigate the benefits of deferring enrollment. For example, a base price that is then multiplied by some economic factor (say, indexed at interest rate or inflation rate) from year-to-year could, in theory, adjust compensation to keep up with inflation while not imposing an incentive for deferred enrollment. Because such an adjustment mechanism would be structural to program design, it should be given due diligence through public discourse if it were to be considered.
3. One objective is to improve certainty for developers and their financial backers by providing a longer-term price signal more aligned with the timing required to develop renewable energy projects. This objective seems to point to deciding on either a two- or three-year ceiling price a priority and committing to keep that ceiling price. Suggesting that a ceiling price may be changed annually defeats the certainty provided by a longer-term ceiling price. However, OER and the DG Board may consider building in thresholds or triggers that could initiate a revision of ceiling prices. This objective also seems to favor a longer-term (three-year) term for ceiling prices over a two-year team.

Request for Comments Prompts

1. Please describe any specific modifications to the modeling implications described in the "Overview of Key Stakeholder Feedback and Modeling Implications" shared on pages 10-28 of the stakeholder presentation linked above, including any specific documentation to substantiate these changes. ***Please note that SEA will hold this documentation (which may include all appropriate redactions as needed) in strict confidence.***

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Q1. Please define 'installed costs', including the components of installed cost included in this calculation.

Q2. Regarding slide 8: Please describe the method used to estimate CRDG values and the definition of 'calculated value'- as used in the footnote. Please also confirm the footnote on slide 8 is accurate. Based on the information provided on slide 8, the following Tables are constructed. It appears that, for Commercial II CRDG and Large Solar CRDG, a 15% premium was applied. For 2023, it is not clear how Commercial I CRDG was derived (purple highlight), and why calculated values were not used for Commercial II CRDG and Large Solar CRDG (green highlight).

2023

	System Size	Non-CRDG	Non-CRDG*1.15	Calculated Values (Footnote)	CRDG
Commercial I	>250-500 kW	22.05	25.36	22.95	25.15
Commercial II	>500-1,000 kW	19.05	21.91	19.95	21.91
Large Solar	>1,000 -5,000 kW	14.35	16.50	15.15	16.50

Q3. Slide 8 includes the following footnote "Average of (1) 60-20% bonus depreciation and (2) no bonus depreciation", which seems to imply some level of bonus depreciation is assumed. However, Slide 28 notes that bonus depreciation is not used. Please clarify whether bonus depreciation was used in calculating ceiling prices and, if so, for which renewable energy classes.

Q4. Regarding the interconnection costs assumed within slide 17: Rhode Island Energy suggests SEA define and/or disaggregate the term 'interconnection costs'. Rhode Island Energy supplied cost data for the interconnection costs charged to developers for renewable energy projects. Developers may incur additional costs related to interconnection but unrelated to electric power system modifications. Without further definition and disaggregation, we are concerned that some costs may be double-counted. We also ask that the same level of scrutiny for cost data be applied to data supplied by non-utility stakeholders in the development of ceiling prices.

Q5. Slide 18 provides estimated CapEx Impact of Meeting Prevailing Wage Requirements. In order to better understand the scale of this increase and vet the reasonableness of wages assumed, Rhode Island Energy requests SEA provide the assumed total labor cost per kW before and after prevailing wage adder is applied.

Q6. One may expect economies of scale to result in lower ceiling prices for larger projects. However, ceiling prices for medium-scale solar are larger than ceiling prices for small-scale solar in 2025 and 2026. Can SEA please explain the drivers of this dynamic and comment on whether the resulting ceiling prices make logical sense?

Q7. Slide 20 includes post-tariff revenue based on forecasted net metering value. What method and underlying assumptions are used in forecasting net metering value? How is this forecast vetted?

Q8. Slide 20 also notes a 40% discount applied to net metering value for some renewable energy classes. Could SEA please provide a more complete description of what this 40% discount represents and how the 40% level was determined?

2. Should the inputs marked in green in the "Characterization of Frequency of Change in [Cost of Renewable Energy Spreadsheet Tool] CREST Model Inputs" section contained on pages 29-35 of the stakeholder presentation linked above be the only inputs to the CREST model that should change on an annual basis during a potential three-year REG program filing? Why or why not?

See above comments regarding year-over-year changes in General Observations, above.

Q9. Could SEA kindly share the CREST model with all inputs and assumptions with Rhode Island Energy?

3. Please describe any requested changes to specific input values shown in "Appendix A: Detailed Cost, Performance and Financing Assumptions" section contained on pages 38-46 of the stakeholder presentation linked above, including any specific documentation to substantiate these changes. ***Please note that SEA will hold this documentation (which may include all appropriate redactions as needed) in strict confidence.***

Q10. How do Total Capital Cost values on slide 40 reconcile with values presented on the slide 44? One may reasonably expect 2023 inputs in slide 44 to be the same as the Total Capital Costs in slide 40.

Q11. Slide 44 shows a year-over-year decrease in Installed Costs, yet Total Capital Cost is increasing on slide 40. Can SEA help reconcile this seeming contradiction by describing the drivers behind this dynamic?

Q12. Please define O&M Costs, including constituent components.

Q13. Regarding slide 40, what is the driver behind the higher O&M costs for CRDG relative to non-CRDG projects in the same renewable energy size class?

Q14. How are the different replacement schedules for different types of inverters accounted for in the ceiling price model? Does SEA make any simplifying assumptions about inverter models and replacement schedules, and if so, what are those assumptions and their reasoning? This question is particularly pertinent for small-scale solar systems.

Q15. One might expect O&M Costs to escalate similarly regardless of renewable energy class because of common drivers (i.e., escalation in labor costs which affect all project sizes). However, the O&M Escalation Factor is set at 2% for small-scale projects but 3% for non-small-scale projects. What is the reasoning behind this difference?

Q16. Regarding slide 41: why is the O&M Escalation Factor 0% for hydroelectric projects? Consistent with the previous question, one may otherwise expect common drivers to result in the same O&M Escalation Factor across resource types.

Q17. In slide 45, how is % Debt derived? Please provide all underlying assumptions (e.g., assumed debt service coverage rations for each renewable energy class).