STATE OF RHODE ISLAND
PUBLIC UTILITIES COMMISSION

IN RE: 2024-2026 RENEWABLE ENERGY GROWTH – CLASSES, CEILING PRICES, AND CAPACITY TARGETS AND 2024-2026 RENEWABLE ENERGY GROWTH PROGRAM – TARIFFS AND SOLICITATION AND ENROLLMENT PROCESS RULES	:	**DOCKET NO. 23-44-REG**

REPORT AND ORDER

I. Overview

In 2014, to facilitate and promote grid-connected generation of renewable energy within The Narragansett Electric Company's load zone (generally Rhode Island), the Rhode Island General Assembly enacted the Renewable Energy Growth Program (Program).[1] Under the Program, each year the Public Utilities Commission (Commission) is required to approve: (1) the classes of renewable energy projects that can participate in the Program; (2) the target amount of capacity that Rhode Island Energy may enroll in each class; and, (3) the ceiling prices the projects may seek from what is generally known as a "feed-in tariff."[2] The Commission is also required to approve annual Tariffs, Solicitation, and Enrollment Rules filed by The Narragansett Electric Company d/b/a Rhode Island Energy (Rhode Island Energy or Company). In June 2023, the General Assembly amended the law to create larger class sizes, add siting restrictions, and allow for multi-year pricing and allocations.[3]

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[1] R.I. Gen. Laws § 39-26.6-1 to 27. Unless otherwise noted, all filings in this matter can be accessed at https://ripuc.ri.gov/Docket-23-44-RENEWABLE ENERGY GROWTH or at the Commission's office at 89 Jefferson Blvd., Warwick, RI 02888.

[2] The Distributed Generation Board and Office of Energy Resources (OER) recommend classes, targets, and ceiling prices to the Commission. Projects in the small classes are paid at the ceiling prices. All other classes must bid into the program up to the ceiling price. An explanation of a feed-in tariff can be found on the U.S. Energy Information Administration's website at: https://www.eia.gov/todayinenergy/detail.php?id=11471 (last visited May 16, 2024).

[3] P.L. 2023, ch. 300 and 301 (June 24, 2023).

On November 15, 2023, Rhode Island Energy filed its proposed 2024-2026 Renewable Energy Growth Program Tariffs, Solicitation, and Enrollment Process Rules with the Commission.[4] On December 20, 2023, the Distributed Generation Board (DG Board) filed a Report and Recommendations Relating to the 2024-2026 Renewable Energy Growth Classes, Ceiling Prices, and Capacity Targets (2024 Report) with the Commission.[5] On January 16, 2024 MassAmerican Energy LLC d/b/a Gridwealth Development, a renewable energy developer filed a timely Motion to Intervene which was unopposed. On March 28, 2024, the Commission approved Rhode Island Energy's Motion to extend the 2023 Program Year by one month, through the end of April 2024, to avoid a disruption of the Program while the Commission finished its review of the first multi-year plan filing.[6]

The Commission conducted two days of evidentiary hearings on April 9-10, 2024, to further examine prefiled testimony and responses to discovery requests. The DG Board and OER presented two witnesses, Jim Kennerly and Tobin Armstrong, their consultants from Sustainable Energy Advantage, LLC (SEA). These witnesses also provided written testimony and responded to discovery over the course of the proceedings. Rhode Island Energy presented three witnesses, Carrie Gill, PhD, Senior Manager of Electric Regulatory Strategy, Kenneth Campbell, Senior Energy Request for Proposals Specialist, Gerald Ferris, Supervisor to the Interconnection team, and David Bates, a Distributed Generation Program Manager. Dr. Gill and Mr. Campbell had provided prefiled testimony and discovery responses along with Erica Russell-Salk, Manager of

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[4] Renewable Energy Growth Program Tariffs, Solicitation, and Enrollment Process Rules.
[5] Report and Recommendations Relating to the 2024-2026 Renewable Energy Growth Classes, Ceiling Prices, and Capacity Targets (Dec. 20, 2023).
[6] As a result of the complexities of developing the first multi-year proposal, the DG Board filed its recommendations a month later than if has in the past. Typically, the Commission conducts its review and ruling in the February to March timeframe. The one-month delay in filing resulted in scheduling conflicts with other annual filings in March, resulting in the hearing and ruling in this matter to be moved into April. No party or member of the public objected to the requested extension.

Customer Energy Integration. Ms. Russell-Salk was unavailable for the hearing so the other witnesses adopted her testimony as necessary. Gridwealth presented Ian Springsteel, Vice President of Policy and Regulatory Affairs who also submitted prefiled testimony. The Division presented its consultant, Michael Brennan who had also submitted prefiled testimony.

At an Open Meeting held on April 29, 2024, following a full review of the record, including testimony, comments, discovery responses, evidentiary hearings, and post-hearing comments made by the DG Board,[7] Rhode Island Energy, intervenor MassAmerican Energy LLC d/b/a Gridwealth Development (Gridwealth), and the Division of Public Utilities and Carriers (Division), the Commission: (1) approved all proposed renewable energy classes for the three years; (2) approved the proposed capacity targets for Program Year 2024, with a conditional approval of the Large Solar II and Large Solar III categories; and (3) approved modified ceiling prices for each of the three years for each class, with the exception of the Small Solar classes which were only approved for Program Year 2024. The Commission rejected proposed incentive payment adders for renewable energy projects requiring remediation and invited the parties to file a new pilot proposal for consideration.

The Commission also approved Rhode Island Energy's tariffs and enrollment rules with modifications that reflect the Commission's decisions on capacity allocation and ceiling prices. The Commission rejected a proposed tariff change related to performance guarantee deposits. The Commission approved Rhode Island Energy's final compliance filing on May 9, 2024, for effect May 1, 2024.[8] The Commission also directed Rhode Island Energy to provide the DG Board with

[7] On February 2, 2023, the DG Board filed Rebuttal Testimony in response to the Division's testimony on the treatment of bonus depreciation.
[8] Rhode Island Energy filed its initial compliance filing on April 30, 2024. On May 2, 2024, the Commission approved it subject to incorporating certain clarifying language, making no substantive changes. The Company filed the revised compliance filing on that same date, following the open meeting.

cost estimates, market value of products purchased, and net cost to ratepayers for its consideration as it develops the Program Year 2025 capacity allocation and Small Solar ceiling price proposal.

Finally, the Commission will open a docket to develop an integrated clean and renewable energy procurement plan to consider technology options, procurement mechanism options, and policy alternatives. The Commission seeks to complete the process by July 1, 2025.

II. Renewable Energy Classes

The DG Board proposed fifteen renewable energy classes, including different sized solar, wind, anaerobic digestion, hydropower, and community remote distributed generation. The tariff length for each technology and type was twenty years, except for the Small Solar I category. As in prior years, Small Solar I tariff lengths were fifteen years.[9] For the first time, in response to the 2023 statutory amendments creating three categories of Large Solar classes, the DG Board proposed three solar classes in excess of 5 MW. No party objected to the proposed classes and the Commission found that the classes are consistent with the law.

III. Ceiling Prices

The DG Board proposed ceiling prices for Program Years 2024, 2025, and 2026. The proposal was developed through a facilitated stakeholder process. The DG Board and OER routinely engage SEA to manage the stakeholder process and to develop and support the proposals. SEA utilizes the Cost of Renewable Energy Spreadsheet Tool (CREST) model, a publicly available discounted cash flow analysis tool. According to witnesses Jim Kennerly and Tobin Armstrong of SEA, the CREST model "is designed to calculate the cost of energy, or minimum revenue per unit of production, necessary for the modeled project to cover its expenses, service its debt obligations (if any), and meet its equity investors assumed minimum required after-tax rate

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[9] DG Board Recommendation at 5.

of return."[10] The Commission has previously accepted the CREST model and considered its results when setting ceiling prices in the Renewable Energy Growth Program tariffs. Projects enrolled in the Small Solar classes receive the ceiling price while projects in all other classes bid in a competitive solicitation.

The recommended ceiling prices for program year 2024 were all higher than the 2023 ceiling prices for each class. Also, the ceiling prices proposed for Large Solar III and Large Solar IV were higher than those for Large Solar II.[11] In other words, at the proposed ceiling prices, ratepayers would pay less for three 5 MW Large Solar projects than for one 15 MW Large Solar IV project. The same is true of the relationship in ceiling prices between Small Solar II and Medium Solar. At the proposed ceiling prices, ratepayers would pay less for eight 25 kW Small Solar II projects than for one 200 kW Medium Solar project.[12]

In support of increasing ceiling prices from Program Year 20203 to Program Year 2024, Mr. Kennerly and Mr. Armstrong's testimony cited limitations on the supply of parts and labor, geopolitical events, higher interest rates, and the expected expiration of a grace period on solar panel import duties as factors applying upward pressure to distributed renewable energy project costs.[13] In support of the atypical proposal that some larger solar categories have higher ceiling prices than smaller solar classes, the witnesses raised two specific factors. First, the witnesses stated that the statutory restriction on developing Renewable Energy Growth projects in core forest areas and the requirement that certain larger projects be located on preferred sites have increased the costs of deploying renewable energy projects.[14] Second, Mr. Kennerly and Mr. Armstrong

[10] Jt. Test. of Kennerly and Armstrong at 22.
[11] DG Board Report, at 9 (Table 3).
[12] *Id*.
[13] Jt, Test, of Kennerly and Armstrong, at 18-19.
[14] *Id. at* 20

explained that interconnection costs borne by developers affect the overall capital costs of projects, and indicated that they arrived at input values for interconnection costs by using a mix of Rhode Island specific and regional interconnection cost data points from states with high-penetration of distributed generation.[15]

The DG Board also proposed a price adjustment mechanism in response to concerns about the uncertainty in predicting future market conditions and project costs raised by the Division and Rhode Island Energy. The SEA witnesses explained that the proposed price adjustment mechanism would be used to update the 2025 and 2026 Program Year ceiling prices if any of the following minimum thresholds are met: (1) major deviations (±10%) from SEA's forecasted installed capital cost inputs; (2) major deviations (± 50 basis points (bps)) in interest rate on term debt inputs from SEA's forecasted values; and (3) any changes in state or federal law, regulation, or policy that have a direct, material, and mandatory impact on program design, cost, performance, and financing inputs for eligible projects, or upon any other factor that would change the expected rate of return for such projects.[16] In response to discovery, SEA clarified that the proposed price adjustment mechanism would recalculate the ceiling prices by adjusting only one relevant input to the CREST model, as opposed to updating all of the model inputs based on the most up-to-date information.[17]

A. Division's Position on Ceiling Prices

The Division filed testimony from its consultant, Michael Brennan, opposing the Small Solar Ceiling prices, supporting the remaining 2024 ceiling prices, and opposing establishing ceiling prices for all classes for the following two years due to the volatility of future market

[15] *Id. at* 22
[16] *Id*. at 30-31.
[17] DG Board Response to PUC 2-12.

conditions. Mr. Brennan challenged the financing and post-tariff revenue assumptions used in the modeling of the Small Solar ceiling prices.[18,19] With respect to the 2025 and 2026 ceiling prices for all classes, Mr. Brennan highlighted the recent volatility in interest rates tied to treasuries, which increases the uncertainty of future financing predictions beyond 2024.[20] He also mentioned the potential cost reductions due to easing supply chain constraints, particularly in solar panel pricing.[21] While these cost savings could benefit larger competitively bid projects, Mr. Brennan emphasized the Division's strong opposition to setting multi-year ceiling prices for the Small Solar classes that are not subject to competitive bidding.[22]

Mr. Brennan strongly opposed SEA's assumptions about the value of the post-tariff revenue in determining the proposed ceiling prices. He explained that in previous filings, SEA estimated the future value of net metering credits by escalating current values to future years, and then reduced this value by 40 percent to account for uncertainty in net metering policy. The 2023 changes in the Renewable Energy Growth statute require the Renewable Net Metering Credit be reduced by 20 percent for virtual net metering projects once the cumulative capacity of such facilities reaches 275 MW.

In response to this legislative change, the DG Board's consultant reduced the expected value of net metering by an additional 20 percent on top of the 40 percent already assumed in the

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[18] Post-tariff revenue refers to the ability of Renewable Energy Growth facilities to transition to the net metering program at the end of their tariff term.
[19] Brennan Test. at 13. Mr. Brennan recommended modifying the Small Solar ceiling prices to include a higher value for post tariff market revenues, and set the Small Solar class ceiling prices at "a level that is more in line with the 2022 prices." While he expressed similar concerns with larger classes, and suggested ceiling prices should be recalculated to account for recent interest rate changes, he stated: "Recognizing that the competitive classes will reflect the changing dynamics of interest rates, project costs and other factors in the prices that they bid and that Rhode Island Energy will select only the most competitive eligible projects in the open enrollments, the Division believes that the ceiling prices recommended by SEA and the DG Board should be approved for Program Year 2024." *Id*. at 14-15.
[20] Brennan Test. at 11-12, 15.
[21] *Id*. at 15.
[22] *Id*. at 15-16.

ceiling price calculation. Mr. Brennan argued that the "whole point of the 40% reduction was to account for precisely these types of changes in law, in other words, the 20% reduction in the new law should be considered part of the 40% adjustment that has been historically assumed for the purpose of making a conservative estimate of future net metering credit values."[23] Therefore, Mr. Brennan concluded that SEA's revised assumptions about post-tariff revenue are unreasonable and likely produce ceiling prices that are too high.[24]

B. Hearing

Where the Commission has previously accepted the CREST modeling as appropriate to developing ceiling prices, the impact of inputs is an important component of the Commission's review. In the current proposal SEA changed both the inputs and methodology for developing the ceiling prices from previous years, due to low enrollment in 2023 (arguably because the ceiling prices for 2023 were set below what a reasonable investor would expect to achieve).[25] In the past, SEA averaged the lowest quartile and median costs to derive input costs. In the current proposal, SEA used a blend of median and 75th percentile costs for projects larger than 25 kW, and solely median costs for smaller projects. This change led to an increase in the estimated installed costs, and, correspondingly, the ceiling prices for small and large solar projects compared to the old methodology with updated inputs.[26]

Evidence showed that using updated cost data with the old methodology would increase the 2024 ceiling prices over the approved 2023 ceiling prices, but not as high as the current proposal before the Commission.[27] Likewise, using 2023 inputs with the new methodology would

[23] *Id*. at 8-9.
[24] Brennan Test. at 8-9.
[25] *Id*. at 37.
[26] DG Board Responses to PUC 1-26.
[27] *Id*.

have resulted in higher ceiling price proposals for 2023.[28] At the hearing, DG Board witness, Mr. Armstrong agreed that updating the inputs with the old methodology would have resulted in better participation in 2023.[29] Given that changing either the inputs or the methodology would result in higher ceiling prices, the Commission questioned whether updating both the installed costs and changing the methodology simultaneously resulted in ceiling prices that were too high.

Additionally, at the hearing, it became clear that SEA's assumptions about interconnection costs might not reflect the fact that distributed generation projects in Rhode Island have purpose-built substations and tie-lines to existing substations that go directly to the transmission system but are classified as sub-transmission and considered distribution-connected.[30] SEA's calculation of interconnection costs was based on a simple average of three states' interconnection costs, potentially resulting in higher interconnection cost inputs than experienced by Rhode Island facilities.[31] Finally, no consideration was given to the fact that certain types of interconnection costs allocated to DG projects may be subject to cost sharing or reimbursement by ratepayers.[32]

Another issue addressed at the hearing was the precision of ceiling prices. Ceiling prices have typically been set out to two decimal points. While the proposed 2024, 2025, and 2026 ceiling prices are also distinguished out to two decimal places, witnesses for the DG Board could not provide evidence that the model is precise out to two significant figures. During the hearing, the witnesses testified that they had not analyzed whether the precision of the inputs into the CREST model reasonably resulted in the purported level of precision of the outputs.[33]

[28] DG Board Responses to PUC 1-24.
[29] Hr'g. Tr. at 115.
[30] Hr'g. Tr. at 144-48.
[31] DG Board Responses to PUC 1-16.
[32] DG Board Response to PUC 1-18.
[33] Hr'g. Tr. at 122-39.

Turning to the issue of the ceiling price adjustment mechanism design, the stated goal was to address situations where approved ceiling price changed due to underlying input changes, such that the return was no longer within a zone of reasonableness.[34] The DG Board's proposal would use only two inputs (installed costs or interest rates) to trigger adjustments and re-run the CREST model based solely on these inputs without refreshing all inputs.[35,] Responses to discovery questions showed that the proposed mechanism did not have a consistent impact on ceiling prices, with one provision allowing the return to investors to reach 8 percent before triggering an adjustment, while the other only allowed the return to reach 9.3 percent.[36]

C. Commission Findings on Ceiling Prices

The Commission must determine whether the ceiling prices for each technology will allow a private owner to invest in each project at a reasonable rate of return, and the Commission may, but is not required to, approve ceiling prices for up to three years. After considering the evidence and final positions of the parties, the Commission approved 2024, 2025, and 2026 ceiling prices for all classes except Small Solar. The Commission was persuaded that setting ceiling prices for 2024, 2025, and 2026 allows the market to plan for larger projects with longer lead times. The Commission approved the proposed ceiling prices for Small Solar I and Small Solar II for 2024 only, because it was persuaded by the Division's testimony that the financial markets are too volatile to set 2025 and 2026 prices, particularly where enrollment is not based on a competitive bid process.[37] The risk of setting the ceiling price too high is greater for non-competitive classes

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[34] Hr'g. Tr. at 199.
[35] OER/DG Board Response to PUC 2-12.
[36] Hr'g. Tr. at 192-97; OER/DG Board Responses to PUC 2-13 and PUC 2-14.
[37] Brennan Tr. at 15-16.

because, unlike competitive classes, there is no such opportunity for ratepayers to benefit from lower actual costs through competitive bidding.

The Commission also found that that ceiling prices for each size class should not be higher than the price for lower size classes. Specifically, Medium Solar should be set no higher than Small Solar and Large Solar III and IV should be no higher than the ceiling price for Large Solar II.[38] This decision reflects Division witness Brennan's testimony that "if larger projects don't achieve economies of scale, it doesn't seem like there's much value in pursuing them,"[39] and his advice that it would not be reasonable for ratepayers to pay for the same number of megawatts at a higher price.[40]

Even with this requirement, the evidence demonstrates that the approved ceiling prices are still designed to allow a private owner to invest in a project of those respective sizes at a reasonable rate of return.[41] The record indicates that the proposed ceiling prices might be higher than necessary to achieve target returns due to the changes in methodology, potentially overstated interconnection cost inputs, and the Division's argument that SEA applied an excessively large discount to the assumed value of post-tariff revenue. While the CREST model assumes a certain return to investors, the record shows that SEA has both previously and currently assumed a range of reasonable returns.[42] Furthermore, while each of the inputs may have a certain level of accuracy,

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[38] All other class size ceiling prices followed a decreasing price with increased size and did not require further Commission action.
[39] Hr'g. Tr. at 506.
[40] Hr'g. Tr. at 502.
[41] Under the proposed price adjustment mechanism, the rate of return for Large Solar I could go as low as 8% before the DG Board would trigger the price adjustment mechanism in the context of a multiyear ceiling price plan. This suggests that the rate of return could got down over 2 percentage points before it would be unreasonable. OER/DG Board Response to PUC 2-13.
[42] SEA assumes a 10.3% internal rate of return for larger solar classes, but PUC-DGB 4-3 shows that the assumed IRR has ranged from 9.3% to 13% for medium solar and larger classes over the last 5 years.

there are times when SEA uses its professional judgment and uses average cost inputs.[43] Finally, no evidence was presented to show that the model's results are precise to two decimal places, indicating that the approved ceiling prices may not be significantly different from the proposed prices.[44]

The Commission rejected the price adjustment mechanism, deciding instead that any party may request that the prices be adjusted prior to the start of the next program year. However, the requesting party must provide evidence that the established prices will not result in the statutorily "reasonable rate of return," bearing the burden of proof for the adjustment. The Commission will consider these proposals after allowing other parties to respond.

The Commission rejected the proposed design of the ceiling price adjustment mechanism because it is inconsistent with regulatory price-setting principles. First, by choosing two discrete inputs (installed costs or interest rates) that would trigger the price adjustment and re-running the model using only the triggering event instead of all inputs would be akin to single-issue ratemaking, something disfavored by this and other regulatory commissions.[45,46] Because the Commission views the ceiling price setting process as akin to setting a revenue requirement, similar to that of a utility, the Commission cannot approve an adjustment mechanism that only looks at one input to adjust a previously approved revenue requirement without reviewing the totality of costs.

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[43] Hr'g. Tr. at 133.
[44] The adjustments in ceiling prices to Large Solar III and IV are within two decimals.
[45] For clarification, in the past, SEA has previously updated ceiling prices when federal tax policy has changed between the initial ceiling price filing and the respective evidentiary hearing (one to two months apart). While SEA, in that instance, is refreshing just one input, it is doing so in the context of the same ceiling price setting process where all other costs have also been refreshed. The proposal before the Commission in this case is to only refresh one input in a calculation that was based on many different inputs at a previous point in time.
[46] OER/DG Board Response to PUC 2-12.

Furthermore, the triggering events would result in significantly different returns that investors would expect.[47] The inconsistent impact fails to support the equivalent of single-issue ratemaking. This is particularly true where Mr. Kennerly testified that he was not necessarily proposing an 8% or 9.3% return as a reasonable target return.[48] Finally, SEA had not considered approaching the price adjustment mechanism as re-running the model with refreshed inputs to determine if the resulting return was unreasonable.[49] For these reasons, the Commission rejected the design of the price adjustment mechanism.

IV. Megawatt Allocation Plan

The DG Board made recommendations to the Commission regarding annual megawatt solicitation targets for each of the proposed renewable energy classes. The DG Board proposed a total target of 107.5 MW for Program Year 2024. The DG Board also proposed capacity allocation targets of 133.5 MW and 185.5 MW for Program Years 2025 and 2026, respectively.[50]

In addition to proposing the total capacity allocation, the DG Board also proposed how much capacity to allocate to each technology and size class for program years 2024, 2025, and 2026.[51] The DG Board's testimony explained that its consultants initially found that it was unclear how much capacity was viable for bidding into the Large II, III, and IV classes during the three-year period. Therefore, the DG Board initially allocated zero capacity to those classes for the 2024 program year.[52] Following the first stakeholder meeting, Rhode Island Energy proposed allocating capacity to Large Solar II and Large Solar III based on a review of the interconnection queue and

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[47] Hr'g. Tr. at 192-97; OER/DG Board Responses to PUC 2-13 and PUC 2-14.
[48] Hr'g. Tr. at 197.
[49] Hr'g. Tr. at 198-99.
[50] Small Solar categories are enrolled on a continuous open enrollment through a first come, first serve basis. The remaining classes are enrolled through a competitive bid process that occurs three enrollments during the program year. Joint Test. at 17.
[51] *Id*. at 57.
[52] *Id*. at 60.

belief that the transmission level Affected System Operator (ASO) studies being conducted in compliance with ISO-NE requirements would be completed in time for projects to enroll in the 2024 Program Year.[53]

A. Division's and Gridwealth's Positions on Megawatt Allocation Plan

Mr Brennan noted that while the 2023 legislative changes mandate reserving 30 MW of the annual recommended capacity target for projects less than 1 MW, the proposed capacity allocation for projects under 1 MW is 33.5 MW for 2024, with further increases planned for 2025 and 2026. He recommended limiting the allocation for the smaller classes to 30 MW because the smaller classes are less cost-effective than the larger classes. His testimony explained that limiting the allocation to classes less than 1 MW would allow more capacity to be allocated to more cost-effective classes.[54] Additionally, Mr. Brennan advised that the Division supported a multiyear capacity allocation to allow developers to understand the program capacity available in future years, providing them with critically important information for planning and development.[55]

On behalf of Gridwealth, Mr. Springsteel testified that the proposed capacity allocation plan did not permit substantial and proportional scaling of capacity between Medium, Commercial I, and Commercial II solar classes. According to Mr. Springsteel, the proposed allocations for these classes are inadequate to meet the customer demand for these systems in the coming years. He explained that solar facilities ranging from 25 kW to 999 kW are most likely to be sited on commercial and industrial rooftops, rather than requiring open space, and are less likely to cause issues on the distribution grid. These projects do not require review and study by ISO-New England and affected transmission owner and operators, enabling the projects to move more

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[53] OER/DG Board Response to PUC 4-6.
[54] Brennan Test. at 23.
[55] *Id*. at 24.

quickly and efficiently through interconnection than larger projects. Mr. Springsteel recommended increasing the total annual MW allocations by 27 MW in 2024, 37 MW in 2025, and 47 MW in 2026 by increasing the Medium and Commercial Solar allocations. He also recommended updating the benefit cost analysis supporting the proposed allocation with values from the 2024 edition of the Avoided Energy Supply Component (AESC) in New England analysis instead of the 2021 version, citing that avoided cost components are much higher now than they were in 2021.[56]

B. Hearing

Because the 2023 statutory changes require 30 MW to be allocated for projects under 1 MW and now allows the Commission to approve a total annual allocation up to 300 MW, it is important to understand the rationale for the proposed allocations. The DG Board proposed 107.5 MW for 2024, 133.5 MW for 2025, and 185.5 MW for 2026, with allocations of 33.5MW, 39.5 MW, and 46.5 MWfor classes under 1 MW, respectively[57]. The DG Board's witness testified that SEA and the Office of Energy Resources did not discuss any strategy guiding the capacity proposal.[58]

The SEA witnesses testified that they were directed to "analyze capacity allocations that considered the direct relative cost to ratepayers of the Plan, as well as the availability of capacity presently in Rhode Island Energy's interconnection queue that would be eligible to bid" in each year of the plan.[59] SEA's testimony explained that they analyzed the relative cost-effectiveness of the combined ceiling prices and proposed incentive payment adders.[60] Mr. Kennerly indicated that the direct cost to ratepayers is determined entirely in the context of the benefit cost analysis

[56] Springsteel Test. at 6-13.
[57] DG Board Recommendation at 13, Table 6.
[58] Hr'g Tr. at 255.
[59] Jt. Test. of Kennerly and Armstrong at 57; Hr'g. Tr. at 250-56.
[60] *Id*.

associated with the Renewable Energy Growth Program.[61] Mr. Kennerly explained that cost-effectiveness was determined on a per-megawatt basis.[62]

Additionally, SEA's approach to the benefit cost analysis raised several questions of consistency with prior Commission orders.[63] For example, the record reflected that SEA had included benefits that may not be realized or which are indirect.[64]

Commission questioning at the hearing sought to understand the parties' perspectives on the total net financial cost of the proposed capacity allocation which is determined by comparing the cost of purchasing the resources at the proposed ceiling price to purchasing power at the forecasted market price of energy and renewable energy certificates.[65] Viewing the cumulative above-market cost as a financial loss to ratepayers, the evidence indicated financial impact associated with the 2024 allocation and the three-year allocation. The 2024 program alone was projected to lose as much as $376 million through the long-term commitments of above-market payments, while the three-year allocation, coupled with the proposed ceiling prices, was projected to lose up to $1.34 billion.[66] Based on previously enrolled projects plus the proposals in this proceeding, the rate impact would increase approximately three-fold for all customer classes.

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[61] Hr'g. Tr. at 232-33. The analysis did consider the price effects of current procurements but did not consider how future procurements would impact the analysis. Nor did it fully consider other price suppression elements. Hr'g. Tr. at 397-406.

[62] Hr'g. Tr. at 252-53. Mr. Kennerly agreed on questioning that if the proposal was cost effective on a per MW basis, infinite MWs could be allocated and the benefit cost analysis would still be positive.

[63] Furthermore, it became clear during the hearing that SEA would benefit from additional insight into not just the interconnection queue, but also how many developers had projects in a certain class size to guard against the risk that a single developer could achieve a competitive advantage within the allocation. While the witneses' intent was to limit capacity allocations to lead to competition, it was not clear they had all the necessary information. Tr. at 236-250, 286-87.

[64] Hr'g. Tr. at 233; 407-08; 416-420.

[65] R.I. Gen. Laws §§ 39-26.6-2, 39-26.6-3. The statute directs that the program shall be designed to finance the development, construction, and operation of renewable energy distributed generation projects through a performance-based incentive system that is designed to achieve specified megawatt targets at reasonable cost through competitive processes.

[66] Rhode Island Energy Response to PUC 3-2.

Residential customers' Renewable Energy Growth Factor would almost triple from approximately $4 per month in 2025, to over $11.50 per month in 2034, while the largest customers would see a Renewable Energy Growth factor growing from approximately $525 per month in 2025, to approximately $1,550 per month in 2034.[67]

Mr. Kennerly's and Mr. Tobin's testimony showed that the DG Board did not consider whether the net cost of the proposed capacity targets is reasonable.[68] They testified that they had not been asked to calculate the net cost of the program and that this information was not communicated with the DG Board. Dr. Gill testified that she was unaware of the net cost of the program until the last day of the hearing, with Mr. Campbell advising that it was only in the few days prior to the hearing that he became aware of the cost.[69] In other words, it did not appear that any party was evaluating the financial impact on ratepayers associated with the cumulative impact of the above-market purchases from purchasing the proposed annual allocation of megawatts at the above-market ceiling prices.

Following up on Rhode Island Energy's recommendation to allocate capacity to Large Solar III and IV during the stakeholder meeting, Mr. Campbell testified that in the time since Rhode Island Energy had advised the DG Board that the ASO Study would be completed in mid-June, a subsequent project subject to Federal Energy Regulatory Commission (FERC) jurisdiction had entered the queue and could cause a further delay beyond June.[70]

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[67] Rhode Island Energy Response to PUC 2-3.
[68] Hr'g. Tr. at 150-51; 512-513; 571. SEA did question whether the costs were overstated given that enrollment is usually lower than the annual allocation. However, the Commission finds that the analysis conducted at least provides an order of magnitude for comparison, for example, to the Revolution Wind 400 MW project that, over 20 years, has an expected contract cost of approximately $3.2 billion nominal. Tr. at 576; Order No. 23809 (May 28, 20219).
[69] Hr'g Tr. at 571-72.
[70] Hr'g. Tr. at 595-97.

Addressing the impact on the total projected cost of reallocating capacity from a lower-cost class to a higher-cost class or non-competitive class, Mr. Brennan and Mr. Campbell each testified it would be reasonable to analyze the impact of a significant transfer of capacity to higher cost classes prior to the Company agreeing to a reallocation.[71]

C. Office of Energy Resources Post-Hearing Comments

In post-hearing comments, OER recommended that: (1) Rhode Island Energy be required to update the Commission and parties no later than May 31, 2024, on the status of the ASO Study; (2) Rhode Island Energy provide an update of the volume of projects expected to be eligible to bid into the 2024 Program Year for each of the large solar classes; and (3) if the ASO Study is further delayed into the summer/fall period, then the capacity for the Large Solar II and III classes be paused for 2024 and re-examined with the 2025 Renewable Energy Growth program proposals.[72]

D. Commission Findings on the Megawatt Allocation Plan

The Commission must determine whether the proposed allocation plan meets the statutory requirements, whether to approve capacity allocation targets for one year or multiple years, and whether the capacity allocations to each class should be approved as filed. The Commission approved the recommended 2024 capacity allocations to each renewable energy class. In the absence of a standard for evaluating capacity allocation proposals between 30 MW and 300 MW, the Commission adhered to past practice of combining the statutory minimum and carryover capacity from previous years. In this case, that methodology results in a total capacity allocation nearly identical to the proposed 2024 capacity allocation.[73]

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[71] Hr'g. Tr. at 512, 607.
[72] OER Post-Hearing Comments (Apr. 22, 2024).
[73] Rhode Island Energy's Response to PUC 3-4.

Approval of the 2024 Program Year capacity allocation is, however, subject to removal of capacity from the Large Solar II and Large Solar III classes if the Affected System Operator studies that were anticipated to be completed in June 2024 are delayed, based, in part, on OER's post-hearing recommendation. To effectuate this condition, the Commission directed Rhode Island Energy to provide an update on the status of Affected System Operator interconnection studies no later than May 31, 2024. Rhode Island Energy will also provide an update of the volume of projects expected to be eligible to bid into the 2024 program year for each of the Renewable Energy Growth large solar classes as a component of that update. Rhode Island Energy shall make a recommendation to the Commission and OER on whether it believes healthy competition may be achieved within these class capacity allocations. Regardless of Rhode Island Energy's recommendation, if Affected System Operator interconnection studies are further delayed, Rhode Island Energy will remove the capacity allocated to the Large Solar II and III classes from the Program Year 2024 total capacity allocation.

The Commission declined to approve capacity targets for Program Years 2025 and 2026 and required the DG Board to file a new allocation plan for Program Year 2025. The record did not support the need for the procurement, or the reasonableness of the benefit cost analysis or total cost of the proposed allocations. Nor did the record support Gridwealth's proposed increase to the total MW allocations, including the increases to Medium and Commercial capacity. Gridwealth did not provide evidence to support exceeding the statutory target of 30 MW for project sizes below 1 MW. Furthermore, Gridwealth's proposal would have further increased the rate impacts to customers associated with the above-market ceiling price payments without showing a clear need for the procurement of those resources.

The DG Board's primary case for the proposed capacity allocation was the analysis of net benefits per-megawatt, and the Commission's concerns about the actual realization of the estimated benefits is key to its decision. The benefit cost analysis raises concerns about the actual realization of estimated benefits. The realization of net benefits depends on values that are unlikely to benefit the electric customers funding the program, such as rest-of-pool benefits that flow to customers in other states. The Commission determined in Docket No. 5189, In re: The Narragansett Electric Company d/b/a National Grid 2022 Energy Efficiency Plan, that economic development multipliers are too unreliable for decision-making, and the Commission questions the weight given to the evidence of economic development benefits in this case too (by far the largest or one of the largest categories of benefits presented by SEA).[74,75] Furthermore, there are several reasons that the proposed capacity investments may not reliably deliver the benefits calculated. First, the analysis did not consider how market price suppression impacts fully hedged contracts or the market value of Rhode Island's existing long-term contracts.[76] Second, the

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[74] In Order No. 24440 at 47, the Commission stated:
The Commission is concerned about the weight that stakeholders may be giving to economic development benefits. While the Commission considers economic benefits in its analysis and evaluation of proposals, it is concerned that these benefits are not as certain as some stakeholders may believe. The Commission notes that, as it does with all evidence, it determines the weight that it will give to evidence of economic benefits. This year, the Commission questioned the weight to be given these economic benefits as it appeared that some of the methods for determining economic benefits appear counterintuitive. For example, evidence presented this year showed that certain incremental spending for information technology would formulaically calculate a different economic benefit impact depending solely on whether it is characterized as residential or C&I spending. This non-sensical result reveals how unreliable the formulaic calculation of economic benefits can be if the dollar figures being yielded by the models are treated too literally as benefits that are reasonably certain to be achieved.

In addition, the Commission is concerned with how the economic development impacts are presented in the annual plan. In particular, the inclusion of large economic benefits in the benefit cost analysis may skew stakeholders or other interested parties' perception of the value of certain program investments. Going forward, as the Company and the Division agreed, the benefit cost ratios that Company presents should not include the economic benefits but should present those benefits separately.

[75] SEA Schedule 12, Updated Docket 4600 Benefit Cost Analysis of Megawatt Allocation Plan and Incentive Payment Adders, at. 17.

[76] H'rg. Tr. at 407-08; 558-60.

property value loss and loss of ecosystem services were not included in the analysis.[77] Third, the volatility of the AESC suggests that the avoided cost values benefits can swing significantly and often.[78, 79] Therefore, the benefit cost analysis did not produce reliable results upon which to base the total megawatt capacity allocations for the multi-year program. [80]

Further, there was insufficient evidence to support that the proposed multi-year capacity allocation would achieve the purpose of the Renewable Energy Growth program to procure resources at reasonable cost, as required by the statute. As discussed above, the cumulative financial impact of procuring the proposed three-year allocation at the above-market payments totaled $1.34 billion. The record is clear that no party considered the reasonableness of procuring those allocated amounts at that net financial cost to ratepayers. Relying on an analysis of net benefits per megawatt to guide the allocations suggests that infinite capacity could be cost-effectively procured; this framing may have obscured the parties' understanding of whether the total cost of the proposed capacity allocation is reasonable. Just because a procurement may be cost effective under one set of analyses does not automatically lead to the conclusion that the procurement is necessary or appropriate for ratepayer funding.

The Commission emphasizes that the program's size must be justified based on need and reasonable cost. Therefore, when OER and DG Board file the proposed capacity allocations for Program Year 2025, they must consider the overall total cost of the program based on the approved ceiling prices and quantities. To support this, Rhode Island Energy is directed to provide the

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[77] Hr'g. Tr. at 356.
[78] The benefit cost analysis was originally performed by SEA using the 2021-2023 Avoided Energy Supply Costs in New England (AESC) analysis. On March 15, 2024, OER/DG Board submitted an updated benefit cost analysis based on the 2024-2026 AESC analysis.
[79] Hr'g. Tr. at 407-10.
[80] SEA Table 12 and SEA Revised Table 12. Even using the updated AESC analysis, projects below 1 MW do not result in a benefit cost ratio greater than 1.0. These, however, as previously noted, are statutorily required to be procured up to 30 MW.

following information to the DG Board for their consideration of the Program Year 2025 allocations and Small Solar ceiling price: (1) overall cost of the program; (2) value of market products which should include the impact of other procurement activities; and (3) net cost to ratepayers and bill impacts.

Rhode Island Energy will also be required to justify the prudence of any capacity reallocation agreed to between itself, the DG Board, and the Office of Energy Resources. This requirement is intended to ensure that any reallocation during the program year, given the variability in project sizes and prices, is justified. If capacity is reallocated from a class with a lower price to one with a higher price, or to a class with a worse benefit-cost ratio, the Company must make a compelling case for the reallocation at the cost recovery stage.

Finally, the Commission ruled to open a docket to develop an integrated clean and renewable energy procurement plan that considers technology options, procurement mechanism options, and policy alternatives. A primary challenge in this case was determining an appropriate annual procurement target for the Renewable Energy Growth Program. Gridwealth's Post Hearing comments highlighted the need for a comprehensive plan to serve Rhode Island's load requirements before maximizing the General Assembly's authorization to allocate up to 300MW per year. In its comments, Gridwealth recognized the Commission's expressed concern that Rhode Island lacks such a plan to fully understand and best serve its clean energy load requirements.[81]

As the Commission considers the expansion of the Renewable Energy Growth Program while maintaining reasonable cost to ratepayers, developing a more integrated clean energy strategy is essential. This strategy will guide proponents, intervenors, and the Commission in making informed procurement decisions, that align with various statutory mandates. An

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[81] Gridwealth Post Hearing Comments at 5.

integrated clean energy procurement plan will inform future decisions by detailing how clean energy is procured, the state's requirements, the total MW needed for various outcomes, and the most cost-effective programs or processes, especially with ratepayer funds are involved.

V. Incentive Payment Adders

OER and the DG Board proposed a cents-per-kWh adder for projects sited on landfills or brownfields. The proposal was modified during the proceeding with the final proposal providing an adder ranging from 3.3 cents per kWh to 4.3 cents per kWh above the awarded performance-based incentive rate for projects sited on uncapped landfills. Projects located on Brownfields/Superfund sites would receive an adder ranging from 2.7 cents per kWh to 3.6 cents per kWh above the awarded performance-based incentive rate. The adder was developed based on large solar modeling but the DG Board chose to also apply an adder to smaller solar classes, indicating that those smaller projects still have a "strong chance" of being cost effective.[82] The adder was based on the "incremental cost methodology" where SEA considered additional costs associated with siting on these type of sites.[83]

A. Division's Position on Incentive Payment Adders

In his testimony, Mr. Brennan testified that the Division did not support the proposed adders because the benefit cost ratio for projects with adders in each class is lower than the benefit cost ratio for that class with no adders.[84] Mr. Brennan further testified that the proposed adders do not result in net benefits to ratepayers once the economic development benefits were removed. According to Mr. Brennan, including those benefits, as SEA did, is inconsistent with the

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[82] OER/DG Board Jt. Test. at 52-53.
[83] *Id*. at 53-55.
[84] Brennan Test, at 18.

Commission's directive in energy efficiency proposals.[85] Using the information provided in OER/DG Board Response to PUC 2-8, specifically Tables 11 to 15, Mr. Brennan stated that "[t]hese revised Tables present the BCA results without the inclusion of economic development benefits. The resulting B/C ratios declined substantially for all classes. For the adder cases, the resulting B/C ratios were all below 1.0 for all proposed adder cases."[86] Therefore, according to Mr. Brennan, approval of the adders would not result in a prudent ratepayer investment.[87]

In addition, because the adder reduces the cost-effectiveness of numerous renewable energy classes, Mr. Brennan indicated that the Division found "no compelling reason to support this adder." He suggested the Division could consider supporting an adder if it results in the same or improved cost-effectiveness. He advised that such an adder needs to be less costly than that which was proposed.[88]

B. DG Board Rebuttal Testimony

In their joint rebuttal testimony filed on March 29, 2024, Mr. Kennerly and Mr. Armstrong indicated that they found the Division's suggestion to scale the adders to their incremental benefits to be without merit, but did not provide further explanation for this position.[89] They asserted, however, that if the Commission were to require such an approach, the incremental benefits would need to include avoided property value losses and ecosystem services/value of open space.[90]

SEA's rebuttal testimony shows the results of benefit cost analysis of the brownfield and landfill adder for each solar class with and without economic development benefits. [91] The

[85] Brennan Test. at 18-19, citing PUC Order No. 24440 (July 22, 2022).
[86] Brennan Test. at 19.
[87] *Id*.
[88] *Id*. at 21.
[89] Jt. Rebuttal Test. of Kennerly and Armstrong at 22.
[90] *Id*. at 23.
[91] *Id*. at 23-26.

testimony shows that in most cases, the incremental costs of the adders exceed the incremental benefits. Furthermore, when economic development benefits are excluded from the analysis, the incremental costs of the adder exceed the incremental benefits in all but two classes. [92]

Subsequently, the DG Board filed a revised benefit cost analysis based on the 2024-2026 AESC analysis. The revised schedule showed that the benefit cost ratio is increased when the value of various avoided costs are updated.[93]

C. Hearing

Various issues were explored at the hearing related to the proposed adders, including the inclusion of conservation benefits and avoided property value loss in the benefit cost analysis together with questions of equity. Mr. Armstrong acknowledged that while larger projects on landfill or brownfield sites might offer measurable conservation benefits, this might not hold true for smaller projects that would be less likely to offset development on greenfields.[94] Questions about the timing and feasibility of project development were asked to understand the impact of the incentive payment adder on the deployment of solar projects. There was also discussion about competition for land use. Mr. Armstrong indicated that, without the adder, fewer projects might be developed without the incentive payment adder, particularly on more challenging sites like unremediated landfills. Another point raised was the economic, environmental, and equity impacts of developing Renewable Energy Growth program projects on landfills and brownfields instead of elsewhere, including questions about the applicability of the study upon which SEA relied. Further questions from the Commission sought to understand the witnesses' perspectives on the equity

[92] *Id*. at 23-26.
[93] Revised Schedule 12.
[94] Hr'g. Tr. at 295.

implications of the proposal for electric customers to subsidize preservation of suburban and rural property values through the incentive payment adder.[95]

D. OER Post-Hearing Comments

In post-hearing comments, OER recommended the Commission consider an 18-month pilot program for the adder, as calculated by SEA, applicable to 10 MW of capacity from the Large Solar I and Large Solar II classes. The target solicitation for projects seeking the adder would be the Fall 2024 open enrollment.[96]

E. Commission Findings on Incentive Payment Adders

The Commission rejected the proposed adder and invited the parties to file a new pilot proposal at least 105 days prior to the proposed commencement of the pilot. The purpose of the pilot should be to align improved siting in the Renewable Energy Growth program with other programs and ratepayers' interests. At a minimum, any such proposal shall consider the design of the incentive, the level of compensation, total program size, and alignment with other sources of funding for similar policy outcomes including, but not limited to the Renewable Energy Fund's Brownfield incentive, Rhode Island Infrastructure Bank (RIIB) Brownfields Revolving Loan Fund, and the Department of Environmental Management's Brownfield Site Preparation and Remediation Grant.

The evidence did not support the DG Board's claims that the proposed adder would avoid property value loss and ecosystem service losses. One of the primary challenges to these claims is that the proponent did not demonstrate that these losses are realized in the base case. The benefit

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[95] Hr'g. Tr. at 295-346.
[96] OER Post-Hearing Comments at 3-4. OER also responded to an issue raised at the hearing about whether projects could qualify for the adder in RENEWABLE ENERGY GROWTH and remote net metering brownfield/landfill incentives. OER advised that its intent would be to clarify the program rules so that a developer would need to choose one incentive program.

cost analysis presented shows that solar development on greenfield sites does not reduce property values or ecosystem services. Consequently, it remains unclear how solar development on a preferred site would avoid such losses. Therefore, the proponent's position appears contradictory, as it suggests no negative impacts from solar in the base case while asserting positive value from solar on preferred sites.

Furthermore, avoided property value loss is not recognized as an eligible benefit under the statute.[97] The supporting paper relied upon by SEA fails to provide a pre-and post-solar analysis, leaving open the possibility that developers are siting projects on the least expensive land, which could have already lower surrounding property values. [98] This raises concerns about causation versus correlation.[99] The paper does not address persistence in the findings. As a result, the Commission has given little weight to the property value study submitted to support the adder's benefit-cost analysis.

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[97] See R.I. Gen. Laws § 39-26.6-22 "In order to provide the electric distribution company and the board with the flexibility to encourage distributed-generation projects to be located in designated geographical areas within its load zone where there is an identifiable system benefit, reliability benefit, or cost savings to the distribution system in that geographical area, or conservation benefit, or climate resilience benefit in that geographical area, the electric distribution company, the board, or the office, shall propose to include an incentive-payment adder to the bid price of any winning bidder that proposes a distributed-generation project in the preferred sites that require remediation. The company, board, or office can also propose disincentive subtractors for projects outside of preferred sites. The electric distribution company also may propose other incentive payments to achieve other technical or public policy objectives that provide identifiable benefits to customers. Any incentive-payment adders must be approved by the commission and shall not be counted as part of the bid price when the bids are selected at an enrollment event."

[98] Gaur, V. and C. Lang. (2020). Property Value Impacts of Commercial-Scale Solar Energy in Massachusetts and Rhode Island. Submitted to University of Rhode Island Cooperative Extension on September 29, 2020. This working paper, based on a study conducted in 2019, has previously been questioned by the Commission. Given the time that has passed, the lack of peer review, and the various law changes, the Commission does not find this to be authoritative for purposes of analyzing the Renewable Energy Growth Program's costs and benefits. (See Hr'g. Tr. at 322-332).

[99] Hr'g. Tr. at 322-325.

The Commission also considered the inequity of the proposal because it would result in requiring all ratepayers, including those without property or those in urban areas, to subsidize the protection of suburban and rural property values.[100]

The Commission acknowledged the adder proposal aims to address a significant issue that it also takes very seriously—the protection of forest land. However, the Commission notes that the DG Board's proposal has left several critical aspects unexplored. Specifically, the DG Board's proposal did not address nor analyze the design and efficacy of existing programs meant to compensate solar developers for brownfield remediation. To address these gaps, the Commission invited the DG Board to investigate existing programs with similar goals and return with a proposal that is aligned with the Renewable Energy Fund Brownfields Solar PV grant program. A new submission should explore flexible forms of the adder. The DG Board must consider alternatives to a cents per kWh rate such as dollars per kW, dollars per acre, or an adder based on actual remediation costs. Additionally, the proposal must consider the possibility of compensating Renewable Energy Growth developers with a grant payment structure, which can be on-going or one-time, the latter of which is similar to the Renewable Energy Fund. It should also align with the parameters of other programs, including the amount of compensation, per project maximum compensation, and total funds available per year or for multi-year caps, and integration with RIIB's Brownfields Revolving Loan Fund, Department of Environmental Management's Brownfield Site Preparation and Remediation Grant.

VI. Rhode Island Energy Renewable Energy Growth Program Tariff and Rule Changes

Rhode Island Energy proposed several changes to the 2024 Renewable Energy Growth Program Tariffs and Rules. The proposed changes to the Tariffs and Rules are intended to: (1)

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[100] Hr'g. Tr. at 335-345.

reflect the 2023 amendment to the Renewable Energy Growth statute; (2) propose changes to the Program stemming from the statutory amendment; (3) address stakeholder and developer feedback to the existing Program; and (4) clarify and improve the overall structure and flow of the Tariffs and Rules.

The proposed changes to address statutory amendments include distinction made for project siting in "core forests" and "preferred sites," the creation of three additional large solar classes, and expansion of targets and enrollment MW targets between one and three years.

Rhode Island Energy proposed additional changes, including recommending that the Tariffs and Rules remove the maximum performance guarantee deposit value of $75,000 and instead for the deposit to scale with the size of the project. Rhode Island Energy also recommended allowing for Letters of Credit, instead of a performance guarantee deposit for Large Solar II, III, and IV projects, and a recommendation that changes to the three-year ceiling prices be permitted if a determination has been made that there has been a significant change to interest rates, total project costs, and state or federal laws or regulations.

The Company also proposed to allow Medium Solar Projects to extent their 24-month deadline for meeting all Tariff requirements by two 6-month periods and proposed to allow for inspection reports to be shared with customer account holders.

A. Positions of the Parties on the Tariff and Rule Changes

The Division recommended that Small Solar projects be removed from the performance guarantee language because these projects are not required to provide performance guarantee deposits. The Division recommended that if the Commission approves incentive payment adders, the associated Rules should be clarified. Specifically, clear definitions for Brownfield (including Superfund sites) and Landfill should be established. The Division also recommended that the process for awarding proportional adders should be clarified, including specifying the minimum percentage of capacity required and validation steps based on "as-built" drawings. Additionally, expectations for cost data submission should be detailed, with developers providing total project costs and incremental costs for preferred sites, both at the application stage and updated upon commercial operation. The Division explained that this data will corroborate the assumptions used to establish the adder value.[101]

B. Hearing

Mr. Campbell explained that the performance guarantee deposit has been assessed as $15 per renewable energy certificate estimated to be generated by smaller facilities in the first year of operation, and $25 per certificate for larger projects, with a cap of $75,000. He indicated that this deposit is based on renewable energy certificate generation to protect ratepayers from the volatility of the certificate market. He also explained that a purpose of the performance deposit was to provide some certainty that the accepted project capacity would materialize. Mr. Campbell had not considered how the proposed changes to the performance guarantee and 2023 legislative changes might prevent other market participants from bidding.[102]

C. Commission Findings on the Tariff and Rule Changes

The Commission rejected Rhode Island Energy's proposal to remove the cap on the performance guarantee deposit without prejudice. After consideration through testimony at the hearing, the Commission was persuaded by Revity Energy's public comment that uncapped performance guarantees could serve as a barrier to entry into the program and at the hearing, the

[101] Brennan Test. at 3-4.
[102] Hr'g. Tr. at 542-49.

Company did not provide a correspondingly convincing reason for needing to raise the cap given the statutory changes to the program.

The Tariffs, Solicitation, and Enrollment Process Rules filed by Rhode Island Energy on November 15, 2023, as revised on January 29, 2024, with modifications ordered by the Commission at the April 29, 2024 and May 2, 2024[103] open meetings, (1) provide a multi-year stream of performance-based incentives to eligible renewable distributed generation projects for a term of years; (2) set forth the rights and obligations of the owner of the distributed generation project and the conditions upon which payment of performance-based incentives will be paid; and (3) contain reasonable non-price conditions. The Solicitation and Enrollment Rules include how the solicitations take place, they include the ceiling prices and term lengths for each tariff, and they include the statutory prohibitions on project segmentation.[104]

VII. Rhode Island Energy's Compliance Filings – May 31, 2024 and July 12, 2024

On May 31, 2024, Rhode Island Energy submitted a compliance filing advising that the ASO Study analysis had been extended to August 2024. The Company also submitted an analysis and recommendation about the volume of projects expected to be eligible to bid into the large solar classes. For Large Solar II, the Company concluded that healthy competition is unlikely given the recommended megawatt allocation. The Company advised that healthy competition may be achieved if the megawatt allocation for Large Solar II is decreased to 10 MW DC for the third open enrollment in Program Year 2024. For Large Solar III, the Company concluded that healthy competition is unlikely for any megawatt allocation in Program Year 2024. Therefore, the Company recommended that the Program Year 2024-megawatt allocation for Large Solar II be set

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[103] Edits for clarity.
[104] *See* R.I. Gen. Laws § 39-26.6-5, setting forth requirements of the Solicitation and Enrollment Rules.

at 10 MW DC, which would have enabled one project to be awarded and that the Large Solar III be reduced to 0 MW.[105]

On July 12, 2024, the Company filed a new Compliance Filing indicating that it had removed the capacity from the Large Solar II and Large Solar III because of the delayed ASO Study timeline. In addition, the Company filed revised Enrollment Rules pages. Finally, the Company indicated that because it had removed the capacity, it was not seeking any Commission action on its recommended changes to the Program Year 2024 Large Solar II or Large Solar III allocations.[106]

Accordingly, it is hereby,

(25141) ORDERED:

1. The proposed renewable energy classes are approved.

2. The proposed 2024 Class Allocations are approved except for Large Solar II and Large Solar III.

3. The proposed 2024 Large Solar II and III allocations are approved subject to the following conditions:
   a. Rhode Island Energy shall provide the Commission with an update no later than May 31, 2024, on the status of Affected System Operator interconnection studies. As a component of that update, Rhode Island Energy will also provide an update of the volume of projects expected to be eligible to bid into the 2024 program year for each of the Renewable Energy Growth large solar classes.
   b. Rhode Island Energy shall make a recommendation to the Commission and OER on whether it believes healthy competition may be achieved within these class allocations.
   c. Regardless of Rhode Island Energy's recommendation, if Affected System Operator interconnection studies are further delayed, Rhode Island Energy will remove the capacity allocated to the Large Solar II and III classes from the PY 2024 total allocation.

4. The recommended 2025 and 2026 Program Year allocations are rejected. The DG Board shall file a new recommended allocation plan for Program Year 2025 by November 15, 2024.

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[105] Rhode Island Energy Compliance Filing (May 31, 2024) at 5-6.
[106] Compliance Filing (July 12, 2024).

5. The proposed ceiling prices for Program Years 2024 through 2026 are approved for all classes except Small Solar I and II subject to the following adjustments:
    a. Program Year 2024 Medium Solar ceiling price shall be 33.15 cents per kWh; Program Year 2025 Medium Solar ceiling price shall be 31.95 cents per kWh; and Program Year 2026 Medium Solar ceiling price shall be 31.35 cents per kWh which is equal to the recommended Small Solar II ceiling price in each respective year.
    b. Program Year 2024 Large Solar III and IV ceiling price shall be 18.05 cents per kWh; Program Year 2025 Large Solar III and IV ceiling price shall be 17.45 cents per kWh; and Program Year 2026 Large Solar III and IV ceiling price shall be 17.25 cents per kWh which is equal to the Large Solar II ceiling price in each respective year.
    c. Any party may request that the prices be adjusted, but an adjustment will be made only if the evidence shows that the established prices will not result in the statutorily required "reasonable rate of return." The party proposing the adjustment, either up or down, will bear the burden of proof.

6. The proposed Small Solar I and II ceiling prices are approved for Program Year 2024. The DG Board shall file new recommended Program Year 2025 ceiling prices for Small Solar I and II by November 15, 2024.

7. If there is any reallocation agreed to between Rhode Island Energy, the DG Board, and OER, the Company will be required at the time of seeking cost recovery of program expenses to justify the prudence of agreeing to the reallocation if the reallocation involves (a) moving megawatts to a class with a higher ceiling price from a class or classes with a lower ceiling price or (ii) moving megawatts to a class with a lower benefit-cost ratio from a class or classes with a higher benefit-cost ratio.

8. The proposed landfill and brownfields adders are rejected. Parties may file a new pilot proposal at least 105 days prior to the proposed commencement of the pilot. The purpose of the pilot should be to align improved siting in the Renewable Energy Growth program with other programs and ratepayers' interests. At a minimum, the proposal shall consider the design of the incentive, the level of compensation, total program size, and alignment with other sources of funding for similar policy outcomes including, but not limited to the Renewable Energy Fund's Brownfield incentive, Rhode Island Infrastructure Bank Brownfields Revolving Loan Fund, and DEM's Brownfield Site Preparation and Remediation Grant.

9. Rhode Island Energy's proposal to remove the cap on the performance guarantee deposit is denied without prejudice.

10. Rhode Island Energy shall provide to the DG Board for consideration of the Program Year 2025 components the following information based on SEA's allocation and ceiling price proposals during the development process: (1) overall cost of program; (2) value of market products (should include impact of other procurement activities); (3) net cost to ratepayers and bill impacts.

11. Rhode Island Energy's Tariffs, Solicitation, and Enrollment Process Rules filed on May 2, 2024 are approved.

12. Rhode Island Energy's Compliance Filing made on July 12, 2024 is accepted.

13. The Distributed Generation Board/Office of Energy Resources request for confidential treatment of certain developer-specific project information is hereby granted under the exception to the Access to Public Records Act R.I. Gen. Laws § 38-

14. The parties shall comply with all other orders and directives of the Public Utilities Commission as set forth in this order.

EFFECTIVE AT WARWICK, RHODE ISLAND ON MAY 1, 2024, PURSUANT TO OPEN MEETING DECISIONS ON MARCH 28, 2024, APRIL 29, 2024, MAY 2, 2024, AND MAY 9, 2024. WRITTEN ORDER ISSUED AUGUST 29, 2024.

PUBLIC UTILITIES COMMISSION

Ronald T. Gerwatowski, Chairman

Abigail Anthony, Commissioner

John C. Revens, Jr., Commissioner

NOTICE OF RIGHT OF APPEAL: Pursuant to R.I. Gen. Laws § 39-5-1, any person aggrieved by a decision or order of the Commission may, within seven days from the date of the order, petition the Rhode Island Supreme Court for a Writ of Certiorari to review the legality and reasonableness of the decision or order.