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December 28, 2020

SENT VIA ELECTRONIC MAIL ONLY [Luly.Massaro@puc.ri.gov]:

Luly E. Massaro
Commission Clerk
Rhode Island Public Utilities Commission
89 Jefferson Boulevard
Warwick, Rhode Island 02888

RE: OER's Responses to the Commission's First Set of Data Requests Directed to the Office of Energy Resources (Issued December 3, 2020) (Docket No. 5088)

Dear Ms. Massaro:

Enclosed for filing on behalf of the Office of Energy Resources ("OER") is a PDF copy of OER's responses to the Commission's First Set of Data Requests Directed to the Office of Energy Resources (Issued December 3, 2020) (Docket No. 5088)

If there are any questions, please feel free to contact me.

Sincerely,

Albert J. Vitali III, Esq.

AJV/njr

Enclosure

c. Docket List: 5088

STATE OF RHODE ISLAND
PUBLIC UTILITIES COMMISSION

IN RE: 2021 RENEWABLE ENERGY GROWTH PROGRAM: CLASSES, CEILING PRICES, AND CAPACITY TARGETS AND 2021 RENEWABLE ENERGY GROWTH PROGRAM – TARIFFS AND SOLICITATION AND ENROLLMENT PROCESS RULES : DOCKET NO. 5088

COMMISSION'S FIRST SET OF DATA REQUESTS
DIRECTED TO THE OFFICE OF ENERGY RESOURCES
(Issued December 3, 2020)

CREST Model and Proposed Ceiling Prices, Classes, and Allocations

1-1. Please provide the original draft ceiling prices, classes, and allocations. Please compare to the proposed and provide the rationale for each change.

The first draft, second draft and final recommended Ceiling Prices and all changes to inputs and assumptions (along with the rationale for each change made between drafts) are documented in JK Schedule 6. The renewable energy classes utilized for developing ceiling prices are documented in the same Schedule.

See page 99 for a comparison of the first and second draft solar ceiling prices to the proposed final solar ceiling prices, and page 100 for the same comparison for Wind, Small-Scale Hydroelectric, and Anaerobic Digestion. The drafted allocation plan that was proposed by the Office of Energy Resources ("OER") in the summer was the same allocation plan that the DG Board approved in October.

Respondents: Jim Kennerly, Sustainable Energy Advantage, LLC ("SEA") and Chris Kearns, OER.

1-2. Please provide the second draft of the proposed ceiling prices, classes, and allocations.

Please see OER's reply to 1-1 regarding the ceiling prices, renewable energy classes and capacity allocations.

Respondents: Jim Kennerly, SEA and Chris Kearns, OER.

1-3. For each class and category, please provide the modeled system size used in the CREST model.

Please see the table below, which contains a matrix of renewable energy classes, eligible system sizes and the corresponding modeled size in CREST.

Renewable Energy Class	Eligible System Size	Modeled Size in CREST
Small Solar I	1-15 kW_{DC}	5 kW_{DC}
Small Solar II	16-25 kW_{DC}	25 kW_{DC}
Medium Solar	26-250 kW_{DC}	250 kW_{DC}
Commercial Solar	251-750 kW_{DC}	500 kW_{DC}
	751-999 kW_{DC}	900 kW_{DC}
Community Remote – Commercial Solar	251-750 kW_{DC}	500 kW_{DC}
	751-999 kW_{DC}	900 kW_{DC}
Large Solar	1-5 MW_{DC}	4.5 MW_{DC}
Community Remote – Large Solar	1-5 MW_{DC}	4.5 MW_{DC}
Wind	$\leq$ 5 MW_{AC}	3 MW_{AC}
Community Remote – Wind	$\leq$ 5 MW_{AC}	3 MW_{AC}
Anaerobic Digestion	$\leq$ 5 MW_{AC}	725 kW_{AC}
Small Scale Hydropower	$\leq$ 5 MW_{AC}	500 kW_{AC}

Respondent: Jim Kennerly, SEA.

1-4. For Large Solar, were any cost efficiencies that may have been gained by co-siting projects with net metering facilities included in the CREST model?

No. The proxy project modeled in CREST is assumed to be a newly developed, permitted, financed, and interconnected project not co-sited with an existing project. We do not assume co-location in setting the Ceiling Prices because:

- **There is not sufficient evidence to suggest that the typical project in a given renewable energy class would be eligible to be co-located with an existing project under the anti-segmentation provisions included in Section 1.1.2.3.2 of National Grid's non-residential REG solicitation and enrollment rules;[1] and**

- **Doing so would *de facto* limit the economic potential for REG projects overall (and would especially limit the potential of projects unable to co-locate).**

Respondent: Jim Kennerly, SEA.

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[1] OER notes that anti-segmentation provisions in National Grid's proposed 2021 REG tariffs and program rules are unchanged from the ones currently included in Section 1.1.2.3.2 of *Rhode Island Renewable Energy Growth Program Solicitation and Enrollment Process Rules for Solar (Greater than 25 kW), Wind, Hydro and Anaerobic Digester Projects (Effective April 1, 2020)*. Given the complex array of potential project configurations that can and cannot qualify under the anti-segmentation provisions proposed for 2021, OER would not recommend making such an assumption when setting Ceiling Prices.

1-5. Referring to Table 4B of the DG Board's recommendations, please explain the proposed changes greater than 10% in the ceiling prices between what was approved by the PUC in 2020 compared to the 2021 recommendations. Please itemize the differences including changes attributable to taxes.

Overall, OER and the DG Board are proposing Ceiling Price increases of 10% or more in the Ceiling Prices for Small Solar II, Anaerobic Digestion, and Small-Scale Hydropower projects, and decreases of 10% or more for Commercial Solar (751-999 kW), Commercial Solar CRDG (751-999 kW), Large Solar and Large Solar CRDG. We detail the changes in assumptions that led to changes in the recommended Ceiling Prices below.

Investment Tax Credit (ITC)-Related Impacts for Solar Projects

The consultants to the Board found that the proposed 2021 Ceiling Price for Small Solar II, which is 10% higher relative to the approved 2020 price, would have only increased by 4% if the 26% ITC value had been maintained by Congress for calendar year 2021. Furthermore, the 14% decrease in Commercial Solar and Commercial CRDG (751-999 kW) would have been 18%, and the 13% decrease in Large Solar and Large Solar CRDG would have also been 18% if the 2020 statutory value had been maintained by Congress into 2021.[2]

The impact on the Ceiling Prices of assuming a 22% instead of a 26% ITC can be found in Table 1 below (which was previously shared in JK Schedule 6).

[2] The values of the hypothetical Ceiling Prices that maintain the 2020 ITC levels converge at 18% due to rounding to a whole number percentage.

Table 1: Comparison of Final Recommended Ceiling Prices (Assuming 22% ITC for CY 2021) with Hypothetical Prices at 26% ITC (CY 2020 Value)

Technology	Size Range kW (Modeled Size kW)	2020 Approved CP	**2021 Final Recommended CP (% Change from 2020 Approved, 22% ITC Statutory Value)**	**2021 2nd Draft CP (% Change from 2020 Approved @ Hypothetical 26% ITC)[3]**
Small Solar I (15 year)	1-10 (5)	29.65	**29.95 (1%)**	***28.75 (-3%)***
Small Solar II	11-25 (25)	23.45	**25.85 (10%)**	***24.35 (4%)***
Medium Solar	26-250 (250)	21.15	**22.25 (5%)**	***21.25 (0.5%)***
Commercial Solar (251-750 kW)	251-750 (500)	18.25	**19.05 (4%)**	***18.15 (-1%)***
Comm. Solar-CRDG (251-750 kW)	251-750 (500)	20.99	**21.91 (4%)**	***20.87 (-1%)***
Commercial Solar (751-999 kW)	751-999 (900)	18.25	**15.75 (-14%)**	***14.95 (-18%)***
Comm. Solar-CRDG (751-999 kW)	751-999 (900)	20.99	**18.11 (-14%)**	***17.19 (-18%)***
Large Solar	1,000-5,000 (4,500)	13.65	**11.85 (-13%)**	***11.25 (-18%)***
Large Solar-CRDG	1,000-5,000 (4,500)	15.70	**13.63 (-13%)**	***12.94 (-18%)***

[3] The values in this column are shown to illustrate the change from the 2020 Approved CP, which also assumes a 26% statutory ITC value, which is in effect during calendar year 2020. The proposed prices, which reflect a 22% statutory ITC value in effect during calendar year 2021, are in the column to the immediate left.

Impact of Expected Loss of Investment Tax Credit in Lieu of Production Tax Credit

On December 31, 2020, the one-year extension of the federal Production Tax Credit (PTC, for which eligible projects can take the ITC "in lieu of") will expire. Therefore, any eligible projects (which include Wind, Wind CRDG, Anaerobic Digestion and Small-Scale Hydropower) will lose access to this credit, which in 2020 was equivalent to 18% of project costs for wind and 30% of project costs for anaerobic digestion and hydropower. The consultants to the Board did not calculate what ceiling prices would have been if these expiring incentives remained in place during 2021, but are highly confident that the vast majority of the difference in price between 2020 and 2021 in these categories is due to expiration of tax provisions.

Changes in Non-Tax Inputs and Assumptions

We detail the non-tax related changes to inputs for the categories with proposed prices +/- 10% from the 2020 approved values below.

***Small Solar II*: The most impactful changes to Small Solar II prices resulted from increases in financing costs derived from a stakeholder survey, as well as feedback surrounding perceived customer risk due to the COVID-19 pandemic. We detail these changes to inputs in Table 2 below.**

Table 2: Changes to Small Solar II Inputs in Proposed 2021 Ceiling Prices

Input	**2020 Approved CPs**	**2021 Proposed CPs**	**Incremental CP Impact**
Upfront Capital Cost ($/kW$_{DC}$)	$2,979	$2,833	Decrease
% Debt in Capital Stack	40%	60%	Decrease
Interest Rate on Term Debt	6.7%	7.0%	Increase
Debt Term (Years)	15	10	Increase
Lender's Fee (% of Total Borrowing)	3.5%	2.3%	Decrease
Target After-Tax Equity IRR	9.5%	13.0%	Increase

***Commercial Solar/Commercial Solar CRDG (751-999 kW):* While updated operating and financing cost assumptions put upward pressure on commercial solar ceiling prices in general, the 14% decline in the Ceiling Price for Commercial projects 751-999 kW arises from the capital cost assumption associated with this new subcategory, which has a proxy system size of 900 kW$_{DC}$ (relative to 500 kW$_{DC}$). Overall, larger projects have lower upfront capital costs and higher levels of system production, which significantly reduce the proposed Ceiling Price for Commercial projects 751-999 kW$_{DC}$ compared to the prior commercial solar category definition. We detail the changes in assumptions for this category in Table 3 below.**

Table 3: Changes to Commercial Solar (incl. CRDG) Inputs in Proposed 2021 Ceiling Prices

Input	2020 Approved CPs	2021 Proposed CPs	Incremental CP Impact
Upfront Capital Cost ($/kW$_{DC}$)[4]	$1,988	$1,869	Decrease
Proxy Project Size (kW$_{DC}$)	500	900	Decrease[5]
Proxy Project Capacity Factor (%)	14.0%	14.6%	
Proxy Project Year 1 Production (kWh)[6]	613,200	1,151,064	
Fixed O&M ($/kW-yr)[7]	$14	$12	Decrease
Insurance (% of Project Cost)	0.27%	0.45%	Increase
Project Management ($/year)	$2,375	$4,000	Increase
Site Lease ($/year)	$12,500	$20,000	Increase
Interest Rate on Term Debt	6.0%	5.25%	Decrease
% Equity Share of Sponsor Equity	25%	40%	Increase
Target After-Tax IRR (Sponsor Equity)	11%	12.5%	Increase
% Equity Share of Tax Equity	75%	60%	Increase
Target After-Tax IRR (Tax Equity)	9.0%	9.5%	Increase

***Large Solar/Large Solar CRDG:* The changes in for Large Solar (and Large Solar CRDG, both of which have a proposed price 13% below the 2020 approved value) inputs are similar for Commercial Solar and Commercial Solar CRDG. Specifically, while certain operating expenses and financing assumptions point towards an incremental increase in those costs, the shift to a proxy Large Solar project size of 4,500 kW$_{DC}$ (4.5 MW$_{DC}$) from 2,000 kW$_{DC}$ (2.0 MW$_{DC}$) as modeled for 2020 results in both a lower upfront capital cost and substantially higher level of system production. Table 4 details the specific changes in assumptions.**

[4] Represents non-CRDG capital cost value. With CRDG, the consultants to the DG Board assume a $150/kW$_{DC}$ upfront cost premium.
[5] The increase in system size and capacity factor (in essence, the ratio of production per unit of nameplate capacity) came together to create a substantial increase in estimated production that was disproportionate to the increase in total costs, which thus led to a reduction in the Ceiling Price.
[6] The analysis assumes a 0.5% annual degradation rate following Year 1.
[7] Represents non-CRDG fixed O&M value. With CRDG, the consultants to the DG Board assume a $25/kW-yr O&M cost premium.

Table 4: Changes to Large Solar (incl. CRDG) Inputs in Proposed 2021 Ceiling Prices

Input	**2020 Approved**	**2021 Proposed**	**Incremental CP Impact**
Upfront Capital Cost ($/kW$_{DC}$)[8]	$1,602	$1,492	Decrease
Proxy Project Size (kW$_{DC}$)	2,000	4,500	Decrease[9]
Proxy Project Capacity Factor (%)	15.3%	15.1%	
Proxy Project Year 1 Production (kWh)[10]	2,680,560	5,952,420	
Fixed O&M ($/kW-yr)[11]	$14.50	$12	Decrease
Interest Rate on Term Debt	6.0%	5.25%	Decrease
% Equity Share of Sponsor Equity	25%	40%	Increase
Target After-Tax IRR (Sponsor Equity)	11.0%	11.5%	Increase
% Equity Share of Tax Equity	75%	60%	Increase
Target After-Tax IRR (Tax Equity)	9.0%	9.5%	Increase

***Anaerobic Digestion:* As noted above, most of the increase in the proposed Anaerobic Digestion Ceiling Price is due to the expiration of the PTC (and thus the ability to claim the ITC in lieu thereof). In addition, the loss of the tax credit leads to higher cost of equity (given that sponsor equity is higher cost than tax equity), which is offset in part by increases in the share of debt (as well as the cost of that debt). Table 5 below these additional revisions to the cost and financing assumptions supporting the proposed 2021 price.**

Table 5: Changes to Anaerobic Digestion Inputs in Proposed 2021 Ceiling Prices

Input	**2020 Approved**	**2021 Proposed**	**Incremental CP Impact**
% Debt	65%	70%	Decrease
Interest Rate on Term Debt	7.0%	6.25%	Decrease
% Equity Share of Sponsor Equity	20%	100%	Increase
Target After-Tax IRR (Sponsor Equity)	12.0%	12.5%	Increase

[8] See Footnote 4

[9] While the change in capacity factor technically reduces the ratio of production to the nameplate project capacity, the increase in system size led to a substantial increase in production that was disproportionate to the increase in total costs, which thus led to a reduction in the Ceiling Price.

[10] The analysis assumes a 0.5% annual degradation rate following Year 1.

[11] See Footnote 7

% Equity Share of Tax Equity	80%	0%	Increase
Target After-Tax IRR (Tax Equity)	9.0%	N/A (since tax equity share = 0%)	Neutral[12]

Small-Scale Hydropower: **Like Anaerobic Digestion, the increase in the proposed Ceiling Price for Hydro is due to the loss of the tax credit, and the impacts of that loss on project financing. However, the consultants to the Board also made some small (but largely offsetting) adjustments to the cost of insurance as well as of debt, which can be seen in Table 6 below.**

Table 6: Changes to Small-Scale Hydropower Inputs in Proposed 2021 Ceiling Prices

Input	**2020 Approved**	**2021 Proposed**	**Incremental CP Impact**
Insurance (% of Project Cost)	2.0%	2.7%	Increase
Interest Rate on Term Debt	7.0%	6.25%	Decrease
% Equity Share of Sponsor Equity	20%	100%	Increase
Target After-Tax IRR (Sponsor Equity)	12.0%	12.5%	Increase
% Equity Share of Tax Equity	80%	0%	Increase
Target After-Tax IRR (Tax Equity)	9.0%	N/A (since tax equity share = 0%)	Neutral[13]

Respondent: Jim Kennerly, SEA. **Please note that SEA is currently developing a new set of ceiling prices to reflect the December 27, 2020 enactment of the Consolidated Appropriations Act of 2021, and will update this data response and their previously filed testimony during the week of January 4th.**

[12] Increase due to lack of tax equity arises from 100% share of higher-cost sponsor equity.
[13] Increase due to lack of tax equity arises from assuming 100% share of higher-cost sponsor equity.

1-6. The total Community Remote Distributed Generation class allocation is increasing from 6 MW to 10.897, or almost double. Was any consideration given to increased land use requirements to support this increase? Please explain.

The DG Board increased the megawatt capacity allocation to the community solar classes and other eligible solar classes, as the DG Board must allocate unused or terminated capacity from prior program years to the upcoming program year plan. Potential increased land use requirements (type of zoned area, lot coverage restrictions, setbacks) with accessing the allocation plan are subject to renewable developers pursuing rooftop or ground mounted systems and working with the municipality and their respective zoning and/or planning boards that review land use applications.

Respondent: Chris Kearns, OER

1-7. Why is the DG Board recommending to almost double the capacity for the CRDG classes when the CRDG ceiling prices are 15% more expensive than the comparable sized solar and wind projects?

The annual program has unused or terminated megawatt capacity from prior program years that must be factored into the upcoming program's megawatt allocation plan by the DG Board to the different renewable classes. The DG Board supports community solar development and agreed with OER recommended allocation plan, including the increased capacity allocated to the community solar classes and the other eligible solar classes.

Respondent: Chris Kearns, OER

1-8. Do the CREST models or proposed ceiling price proposals have any consideration for any future Investment Tax Credits that might be applicable prior to the commercial operation date that 2021 enrolled projects would need to meet?

No. The proxy Solar projects modeled in CREST are assumed to either reach commercial operation during calendar year 2021, or (in the case of non-Small Solar I projects financed by "business" taxpayers, and governed by IRS Notice 2018-59) otherwise qualify as having "beg(un)..construction" under the "Physical Work Test" or the "Five Percent Safe Harbor" in calendar year 2021.

In addition, and as noted in the response to 1-5, SEA plans to file a revised set of 2021 recommended ceiling prices in early January 2021 to reflect the recent enactment of the Consolidated Appropriations Act of 2021, which extended all aspects of the ITC phase-out schedule by two years. The Solar prices filed in that update will reflect an assumption that the newly-enacted 26% ITC value for 2021 will be available to projects seeking REG qualification during the 2021 program year (rather than the

previous statutory value of 22%), and that non-Small Solar I projects "safe harboring" at that value (by satisfying one of the two tests in the IRS Notice listed above) have until January 1, 2026 (rather than the previous statutory deadline of January 1, 2024) to be "placed-in-service" (*read: reach commercial operation*). Thus, the forthcoming revised ceiling prices will implicitly assume that the proxy project will reach commercial operation by January 1, 2026.

Should there be?

SEA recommends maintaining the current approach (as described above) for the purposes of calculating 2021 Ceiling Prices, so long as eligible taxpayers continue to be eligible to claim the ITC after having "beg(un)…construction" in 2021 under the tests in IRS Notice 2018-59 described above. It is SEA's experience that, in Northeast distributed solar markets, project developers, sponsors and their tax equity partners have typically had success with "safe harboring" their projects that are greater than or equal to 25 kW_{DC} under either of the two tests from the IRS Notice described above. In addition, it is also SEA's understanding that most Small Solar I projects have a short enough interval from deal execution to commercial operation to allow for most, if not all, projects to reach commercial operation by the end of the calendar year.[14]

During the 2021 program year stakeholder process, several solar developer stakeholders suggested it might be wise to assume a 10% ITC value to avoid the risk that a project that is unable to be "placed-in-service" prior to January 1, 2024 (e.g., due to interconnection or other delays) would have to be canceled or terminated. However, these comments were made prior to the aforementioned two-year extension of the ITC phase-down schedule (including the two-year extension of the placed-in-service deadline from January 1, 2024 to January 1, 2026). The extension of this deadline makes it highly unlikely that any projects selected during 2021 would be at serious risk of failing to properly "safe harbor" at the 26% level available during calendar year 2021. As a result, SEA does not recommend utilizing the permanent 10% ITC value as the default assumption when calculating and recommending Ceiling Prices for the 2021 Program Year, since doing so would expose ratepayers to increased costs for all Solar classes.

Similarly, while it is possible some well-resourced developers submitting bids during the 2021 Program Year may, for example, have procured equipment under the Five Percent Safe Harbor (discussed above) that are "safe harbored" at the 30% value for 2019, SEA also does not believe it is reasonable to assume all projects selected in 2021 could benefit from such cost efficiencies.

Respondent: Jim Kennerly, SEA. **As noted in the text of the response, SEA is currently developing a new set of ceiling prices to reflect the December 27, 2020 enactment of the**

[14] This is because firms in the Small Solar market sector tend to time their sales cycles to allow potential host customers to reach commercial operation by the end of the calendar year (and thus capture the value of the credits).

Consolidated Appropriations Act of 2021, and will update this data response and their previously filed testimony during the week of January 4th.

1-9. Is the recommended ceiling price that results from the CREST model reduced to account for any non-energy generation benefits that flow to participants? Please refer to the table on Bates page 548 of National Grid's Energy Efficiency filing (http://www.ripuc.ri.gov/eventsactions/docket/5076-NGrid-2021EEPlan(10-15-2020).pdf) for guidance.

No. The Non-Energy Impacts (NEIs) assumed by National Grid in calculating the Docket 4600 benefits and costs for its three-year energy efficiency plan are based on an array of non-energy benefits specifically related to the eligible energy efficiency and demand response measures included in National Grid's program offerings, rather than ones that may be available for Solar projects.

Furthermore, it is not clear to SEA that the NEIs should reduce the compensation provided to project owners in all cases. More specifically, the REG Ceiling Prices are intended to compensate the project's owner(s) for their costs plus a market-rate return on their invested capital, and not all owners of REG-eligible projects are the participating customer that would receive a flow of non-energy benefits and/or costs from the project. For instance, many projects selected in REG Open Enrollments are stand-alone solar projects that only have National Grid as an off-taker. As such, these customers may not be able to realize the NEIs described in National Grid's TRM.

Respondent: Jim Kennerly, SEA.

Carport Adder

1-10. The DG Board proposed continuation of the carport adder pilot to gather more data. Please explain why the proposal also recommends expanding the availability of the adder to the medium solar category.

The DG Board proposed the expansion of the carport adder to the medium solar class as there are other potential parking lot opportunities beyond the commercial and large-scale solar classes. This information would provide additional data on project costs, locations and interconnection impacts for National Grid and the Board to evaluate the 2nd year of the proposed carport pilot program.

Respondent: Chris Kearns, OER.

1-11. What benefits does the medium solar carport category provide compared to rooftop solar in the medium category? What evidence is there that medium solar category facilities are not already being sited on rooftops?

Based on information provided by National Grid for this response, the benefits provided by the medium solar carport category are similar to those provided by the rooftop solar in the medium category. For example, National Grid noted in its testimony (pages 9 and 10) that medium-scale rooftop projects were found to provide meaningful system savings in the form of lower than average interconnection costs and associated ongoing operation and maintenance ("O&M") saving. However, National Grid did not recommend an adder for rooftop projects, noting that these projects represent the majority of projects awarded a COE in the medium-scale category, such that an adder would be likely to provide additional compensation to projects that would occur in the absence of the adder. National Grid's benefit cost analysis suggested that the expansion of the carputer adder to the medium is cost effective per the RI Test in both their central/mid and high benefits scenarios (See pages 27-38 of National Grid's testimony).

Respondent: Chris Kearns, OER.

1-12. Referencing page 65 of Ms. Daniel's testimony, did the total costs of the 2020 pilot adder include National Grid's administrative costs? If not, why not?

No. The costs included in the benefit-cost analysis represent the incremental costs of the carport adder relative to the standard competitive program, and therefore do not include any costs that would be attributable to administering the overall REG program. OER's consultants coordinated extensively with National Grid on the initial design of the carport benefit cost analysis and the main categories of costs and benefits. Any additional administrative costs to implement the Carport adder are expected to be *de minimis* and have not been quantified by National Grid.

Respondent: Jim Kennerly, SEA.

1-13. Given that carports were able to successfully enroll in the full MW allocation for each category in 2020 prior to the third enrollment, what is the rationale for continuing to reserve 20% of each category's allocation for carports?

If there is no reserve placed on the megawatt capacity for the carport opportunities and there are no carport (or minimal) applications submitted during the 1st enrollment period, then National Grid would be required to award all the megawatt capacity from that 1st enrollment period to roof and/or traditional ground mounted solar systems that have completed tariff applications. This could result in no carport applications being awarded, if the solar classes are fully subscribed after the 1st enrollment period.

Historically, the large and commercial solar classes are either fully (or nearly) subscribed due to the competition with those two solar classes in the annual program, as the solar market is developing projects for 8 to 12 months in advance, while waiting for the program capacity to become available for the 1st competitive enrollment period the following program year. Without a reserve on the allocation plan for the eligible solar carport categories, the Board is concerned that this could result in no (or minimal) additional carport data with the 2nd year of the proposed pilot program for National Grid to evaluate.

Respondent: Chris Kearns, OER

Medium Solar Issues

1-14. In Mr. Kennerly's testimony at page 27, he stated that based on data provided by National Grid, it appears that an unusually large number of Medium Solar projects selected during the 1st Open Enrollments of the past several program years have since been terminated, with a significant spike in 2019 after the introduction of competitive bidding in that class. Please explain what is meant by "unusually large number." Why was the first Open Enrollment important to reference?

OER attaches JK Schedule 23, an analysis of the total number of (and capacity associated with) terminated projects since the initial passage of the Renewable Energy Growth Act of 2015, based on data provided by National Grid in June 2020 as part of the 2021 Ceiling Price development process. OER's analysis of this data can be found on the tab entitled "Terminated and Selected".

As shown in JK Schedule 23, at least one Medium Solar project has been terminated in each Open Enrollment between the 3rd Open Enrollment of 2016 and the 1st Open Enrollment of 2019. Importantly, the data also showed that:

- **More Medium Solar projects have been terminated than any other class;**
- **A larger number of terminations occurred in the 1st Open Enrollment of the 2017, 2018 and 2019 program years than during any of the other Open Enrollments of those program years[15]; and**
- **No less than 5 Medium Solar projects have already terminated approximately one year after their receipt of a Certificate of Eligibility (COE) from National Grid.[16]**

Respondent: Jim Kennerly, SEA.

[15] Since a relatively limited time has elapsed between the PUC's approval of the First, Second and Third Open Enrollments of 2019, the first two Open Enrollments of 2020 and National Grid's production of this dataset in June 2020, no projects from those Open Enrollments were shown as of June 2020.

[16] Based on the date of National Grid's report to the PUC on the 1st Open Enrollment of 2019, National Grid appears to have issued a COE in June 2019 to the Medium Solar projects that have now terminated.

1-15. In Mr. Kennerly's testimony on page 27, he expressed concern that there is a disproportionate number of Medium Solar terminations. Please further describe "disproportionate."

Of the terminated projects selected in the 1st Open Enrollment of 2019, the analysis in JK Schedule 23 (in the tab entitled "Terminated & Selected") shows that five of the nine projects terminated thus far are Medium Solar projects.

The analysis also shows that across multiple metrics, Medium Solar projects and overall capacity are substantially more likely to be cancelled relative to Commercial and Large Solar projects (inclusive of CRDG projects within those categories).

The analysis in JK Schedule 23 (in the "Sum of Terminated Proj &MW" tab) shows that the proportion of terminated projects that are Medium Solar projects is much higher than the proportion of selected projects that are Medium Solar. Between 2015 and the 1st Open Enrollment of 2019, 62% of selected projects were Medium Solar, representing 18% of the selected capacity. Over the same period, 66% of the projects terminated were Medium Solar, representing 21% of the terminated capacity.

As shown in Table 8, disparities in project and capacity termination rates are even more pronounced when comparing Medium Solar to the combined termination rates for Commercial and Large Solar projects and capacity. Between the 2015 program year and the 1st Open Enrollment of 2019, Medium Solar project and capacity termination rates exceed those of Commercial/Large Solar projects by 3.8% and 5.0%, respectively. Narrowing the comparison to the period of more elevated Medium Solar terminations (inclusive of the 3rd Open Enrollment of 2016 through the 1st Open Enrollment of 2019) reveals an even more stark disparity between Medium Solar projects and Commercial/Large Solar projects (at 6.4% on a project basis and 10% on a capacity basis).

Table 7: Medium Solar vs. Commercial/Large Solar Termination Rates (by Project and Capacity)

Time Period	*2015-1st Open Enrollment of 2019*	*3rd OE 2016-1st OE 2019*
Medium Solar Termination Rate (by Projects)	25.5%	26.4%
Medium Solar Termination Rate (by MW_{DC})	25.5%	26.6%
Comm'l/Large Solar Termination Rate (by Projects)	21.7%	20.0%
Comm'l/Large Solar Termination Rate (by MW_{DC})	20.6%	16.6%
Medium vs. Comm'l/Large Solar (by Projects)	**3.8%**	**6.4%**
Medium vs. Comm'l/Large Solar (by MW_{DC})	**5.0%**	**10.0%**

Taken together, the high number of early terminations of 2019 selected projects and the increased tendency for Medium Solar projects to be terminated strongly suggests that still more Medium Solar projects are at risk of cancellation in the REG

program and that the number of recently selected projects that are terminated will increase as time goes on.

Given that cancellations of projects of any size can result in substantial sunk costs, inefficiency and frustration for project developers and customers alike, it is OER and its consultants' view that an increased incidence of cancellations concentrated in a given renewable energy class should be avoided where possible, and that assumptions that lead to somewhat more generous compensation for such projects are in order.

Respondent: Jim Kennerly, SEA.

Miscellaneous

1-16. When did the DG Board member seat that is supposed to represent low-income customers become vacant?

The seat has been vacant since 2018.

Respondent: Chris Kearns, OER

1-17. The Commission February 18, 2020 Open Meeting Minutes and subsequent Order states that "**if**" the DG Board wishes to proceed with a carport adder or any other public policy adder in 2021, they must follow the following process consistent with R.I. Gen. Laws § 39-26.6-22." Given the fact that the statement was premised with the word "if," what was the basis for the DG Board concluding that the Commission "requested that National Grid, OER, the DG Board and SEA to collaborate and consider and develop additional 'public policy adders?'" (reference DG Board Report and Recommendations at 18).

OER and the DG Board understand that the PUC never requested additional Adders with the proposed 2021 Renewable Energy Growth Program. This was simply an error in how it was communicated in the Report. It was intended to communicate OER and DG Board understanding of the PUC's desire (communicated in item 4(ii) of the February 18, 2020 Open Meeting Minutes) that OER's consultant would (in the event that National Grid and DG Board decided, as it ultimately did, to develop and recommend adoption of Public Policy Adders), closely collaborate with National Grid in developing said Adders.

Respondent: Jim Kennerly, SEA.