STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS
PUBLIC UTILITIES COMMISSION

IN RE: THE NARRAGANSETT ELECTRIC	:	
COMPANY d/b/a NATIONAL GRID'S	:	DOCKET NO. 4774
RENEWABLE ENERGY GROWTH PROGRAM	:	

DISTRIBUTED GENERATION BOARD'S RESPONSE TO THE COMMISSION'S FIRST SET OF DATA REQUESTS

1-1. **Please provide all Board meeting minutes that include discussions of the current program year.**

Response: Please see attached Exhibit 1 which includes the meeting minutes of the Rhode Island Distributed Generation Board ("Board" or "DG Board") as well as presentations made to the Board during these meetings.

1-2. **Please explain why the larger wind categories (Wind I, II, III) were consolidated into one category (Large Wind). What was the motivation? What was the intended effect of the decision? What other effects are anticipated?**

Response: Large wind project development efforts in Rhode Island are limited, as local municipal permitting of projects has been challenging over the past several years. Historic market participant feedback has indicated that the coordinated development of multiple turbines is necessary for projects to be economically viable. Therefore, the proposal for a single category – rather than three categories representing one, two, and three turbine projects – is intended to more closely represent how wind projects are developed in Rhode Island. Recent examples of large wind projects are the multiple wind turbines installed in Coventry in 2016 and the new large wind project scheduled to be installed in Johnston over the next several months.

1-3. **Please explain why the Board is recommending that the medium scale solar class and associated ceiling price be shifted from a set fixed price submittal to a competitive bidding process. What is the intended effect of this recommendation? What other effects are anticipated?**

Response: The Board recognizes that in a market economy, competitive bidding is a means of achieving cost effectiveness. This has proven the case in the larger and commercial solar classes. Based upon the increased activity within the medium scale solar class in 2017 and the number of applications exceeding the available capacity in 2017 and likely to occur again in 2018, it was determined that the medium scale solar program and associated megawatt capacity should shift to a competitive bidding process in 2018, which is an option under the Renewable Energy Growth ("REG") Program law, R.I. Gen. Laws § 39-26.6-1 et seq. The intended effect is like the other competitive solar bidding categories, that competition will determine the awarded ceiling prices during the three commercial enrollment periods and secure prices at or below the approved 2018 ceiling price.

1-4. **Please explain how the 10% to 15% savings anticipated on all solar installations due to the statewide solar permit application generates an overall savings of 1%.**

Response: The quantitative impact of the new statewide solar permitting application is not yet known. Until actual data are available, the cost savings on permitting expenses is estimated at 15%. According to the United States Department of Energy's Office of Energy Efficiency & Renewable Energy's February 2016 report titled Soft Costs 101: The Key to Achieving Cheaper Solar Energy, permitting expenses represent approximately 3% of total project costs. Therefore, a cost reduction equal to 15% of 3% of total project costs is applied in the CREST model.

1-5. **The table on Slide 7 (Exhibit C, SEA's August 24, 2017 Presentation) shows that Rhode Island had the third highest average installed cost per kW for the small solar I category among northeastern states in 2016. What are the drivers of the relatively high installed costs in Rhode Island? What are the drivers of the relatively low installed costs in Vermont? Slide 11 shows that the 2016 average installed costs for commercial solar are relatively low compared with the small solar I category and low compared to other northeastern states. What accounts for the difference?**

Response: It is difficult to provide firm conclusions as to why all-in installed costs in Rhode Island are different from those in other states without undertaking a bottom-up benchmarking of the components of solar installed costs in Rhode Island and the state in question. (For an example of such a bottom-up analysis in a single state, please see the Vermont Solar Cost Study[1] (which draws on estimates that are approximately two years old)).

However, most differences unrelated to hardware and system performance (which are driven most by (1) module and inverter efficiency/performance and (2) the availability/quality of the solar resource in the area) are the result of differences in non-hardware "soft" costs. These potential sources of non-hardware "soft" cost differences include:

- Differing costs of installation labor (especially if state laws require unionized labor for the installation);
- Differing costs and timelines associated with permitting, interconnection and inspection (PII);
- Differing engineering and design costs;
- Differing customer acquisition costs;

[1] Seddon, L. *Vermont Solar Cost Study: A Report of Photovoltaic System Cost Differences Based on Design and Siting Factors.* Prepared for the Clean Energy States Alliance and the Vermont Department of Public Service, February 2016. Available at: https://www.cesa.org/assets/Uploads/Vermont-Solar-Cost-Study.pdf

- Differing profit expectations; and
- The availability of lower-cost financing options than market rates for debt, sponsor equity or tax equity.[2]

1-6. **Slide 14 (Exhibit C, SEA's August 24, 2017 Presentation) shows that the average and median installed cost for small solar I increased from 2016 to 2017. What is driving the increase in the average and median between 2016 and 2017?**

Response: It is difficult to discern the exact Rhode-Island specific drivers of changes in total installed costs without undertaking a bottom-up benchmarking of the components of solar costs on a year-to year basis. One possible Rhode-Island specific driver of higher costs is that the average system size for small solar I fell from 6.4 kW DC to 6.0 kW DC from 2016 to 2017 (through June 1, 2017, representing a 5.1% drop), which would slightly reduce the scale benefit of having larger systems installed in the Rhode Island market.

On a national basis, GTM Research recently found that customer acquisition costs are expected to rise from 17% to 20% of total installed costs from 2016 to 2017.[3] An increase in customer acquisition costs, without an accompanying decrease in hardware and other non-hardware soft costs delivered by Rhode Island installers, could notionally cause an increase in overall installed costs (as reported through June 1, 2017).

1-7. **Slide 15 (Exhibit C, SEA's August 24, 2017 Presentation) shows that the average and median installed cost for small solar II decreased from 2016 to 2017. What is driving the decrease in the average and median between 2016 and 2017?**

Response: The same difficulty in discerning exact Rhode-Island specific drivers of changes in total installed costs exists for small solar II as for small solar I, as well as potential explanations regarding customer acquisition in the context of overall installed costs. However, while the average small solar II system size fell from 11.2 kW DC in 2016 to 10.9 kW DC in 2017 (through June 1, 2017, representing a 2.2% drop), that drop is smaller relative the 5.1% drop for small solar I, which suggests reduction in system scale benefits is likely to be a less significant driver of increased installed capital costs (as reported through June 1, 2017).

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[2] For more information about non-hardware "soft" costs, please see Woodhouse, et al. *On the Path to SunShot: The Role of Advancements in Solar Photovoltaic Efficiency, Reliability, and Costs*. Prepared for the U.S. Department of Energy SunShot Initiative, May 2016. You may download the report at https://energy.gov/eere/solar/downloads/role-advancements-photovoltaic-efficiency-reliability-and-costs/

[3] Wesoff, E. "Costs to Acquire U.S. Residential Solar Customers are High and Rising". 6 July 2017, Available at: https://www.greentechmedia.com/articles/read/costs-to-acquire-us-residential-solar-customers-are-high-and-rising#gs.TlhwaeY

1-8. **Slide 20 (Exhibit C, SEA's August 24, 2017 Presentation) shows that the weighted average cost for interconnection for the medium solar category for Massachusetts and Rhode Island is $15.10 and the weighted average cost per kW DC for Rhode Island only is $41.92. Please discuss the drivers of the Rhode Island only weighted average cost per kW DC for interconnection.**

Response: Sustainable Energy Advantage, LLC ("SEA") utilized a database of interconnection costs furnished by National Grid to the DG Board and the Rhode Island Office of Energy Resources ("OER"). The values were calculated based on the interconnection costs for systems in varying states, which were divided by the nameplate capacity ratings for systems. The resulting costs were applied as shown on Slide 20 of the August 24, 2017 presentation. However, the data does not specifically explain why the costs are different for systems in Rhode Island relative to Massachusetts or the weighted average of both states. We believe National Grid may be able to provide a more complete and specific answer regarding the observed differences.

1-9. **Why are wind projects assumed to be financed with a greater percentage of debt than solar projects?**

Response: The differences in capital structure estimates between wind and solar are based on stakeholders' recent and historic responses to requests for data on the expected capital structure of REG projects. Wind projects have reported higher D/E ratio expectations than solar projects. This *may* be due to the technologies' differing relationships with tax equity, or the developers' need (or absence of need) to attract external sources of tax equity.

1-10. **What evidence or models did the Board use to determine the internal rates of return (IRRs) used to calculate the ceiling prices? Please provide all data and workpapers supporting this specific input to the ceiling price models. If the IRRs are region-based, please provide a comparison to other regions. If the IRRs are RI-based, please provide a comparison to other states in the region as well as to other regions.**

Response: In general, return targets are based on perceived overall risk (including permitting, development, construction, operating, and revenue risk) rather than geography. The Board and consultants relied primarily on stakeholder feedback to establish target internal rates of return. In response to the June 2017 data request, market participants provided the following target IRRs:

- <u>Solar Respondent #1, quantitative response:</u> 6.5% after-tax equity IRR, levered

- <u>Solar Respondent #1, qualitative elaboration:</u> "*The long-term financing market for renewable energy projects is quite robust. Both private and public capital (through YieldCos) is readily available. In fact, the* *demand for placing capital may actually exceed the supply of quality, bankable renewable energy projects. Accordingly, the long-term capital for projects is readily available*." And, "*Financing of RE facilities in R.I. is generally similar to financing of other Northeast markets. Project sizes in R.I. may be a bit smaller than say Massachusetts which might reduce the number of potential investors as some investors have a project threshold size. But generally R.I. is similar to other Northeast markets.*"

- <u>Solar Respondent #2:</u> Answered other questions, but left the request for IRR feedback blank. The data request instructions indicate that a field left blank will be interpreted as satisfaction with the previous year's assumption.

- <u>Solar Respondent #3</u>: Respondents focusing on the Small Solar market did not provide comments on IRR. These developers, and their customers, tend to focus instead on estimated payback period.

- <u>Solar Respondent #4, quantitative response:</u> "*unlevered returns in the 8-10% range – which translates into a ~12% return on an after-tax, levered basis*"

- <u>Wind Respondent #1:</u> After-tax target equity IRR (%), unlevered = 8%. Levered = 10%

- <u>Wind Respondent #2:</u> Not currently active in RI. Develops larger projects in northern New England. Would need target IRR of 15% or more to enter RI small project market.

- <u>Hydro Respondent #1:</u> After tax target equity IRR, unlevered = 7.0%. After tax target equity IRR, levered = 8.8%

- <u>Other Sources:</u> Several Chadbourne & Parke / Norton Rose Fullbright *Project Finance NewsWire* articles indicating average tax equity requirements of 7% to 9% depending on project size, contract term, contract counterparty creditworthiness, and other factors.

1-11. In determining the proposed ceiling prices, how does the Board consider the competition experienced in previous years?

Response: When the Board has SEA design and develop the annual ceiling prices, the Board has always directed SEA to consider competitive prices from prior years of the REG program, in addition to the regional data and market trends that SEA examines. This directive began during the Distributed Generation Standard Contracts Program and continued into the Renewable Energy Growth Program when it was launched in 2015. SEA factors in competitive results from the prior years REG enrollments when developing ceiling prices for the next year of the REG program.

1-12. **Was the megawatt cap for small solar reached in the previous program year? If so when? And, if so, did the Board consider this as evidence supporting a lower ceiling price for this category? Please explain.**

Response: Yes, the megawatt cap was reached with the small solar program in mid-October. The Board and SEA did take this information into account when developing and approving the 2018 small solar ceiling prices in October.

1-13. **Has the Board investigated whether or not any non-energy benefits and costs (such as property value changes) flow to certain program participants? If not, why not? If so, did the Board include these costs and benefits in calculating ceiling prices? Why or why not?**

Response: Yes, the Board recognizes that ceiling prices are sensitive to non-energy costs and that renewable energy installations can have non-energy benefits, and has factored-in for program participants non-energy items, such as the statewide taxation formula for commercial renewable energy systems that sell power back to National Grid; property tax exemptions on residential solar systems; and the statewide solar permit (building/electric) application. These non-energy items were a result of legislation developed by OER in collaboration with multiple stakeholders that were adopted by the General Assembly during the 2016 (renewable taxation law) and 2017 (statewide solar permit) sessions.

1-14. **Please update the 2018 ceiling prices to reflect the impact of recent tax law changes.**

Response: Please see attached Exhibit 2 which includes a SEA memo regarding the impacts of the federal tax reform law. Due to the Trump Administration issuing a decision on the federal solar trade case, SEA has also included the impacts of the solar trade case decision within this memo. The SEA memo reflects the final recommended ceiling prices for the 2018 REG Program. A summary of the final recommended ceiling prices for the 2018 REG Program is also included within Exhibit 2.

Dated: January 23, 2018
Prepared by or under the supervision of: Christopher Kearns, Office of Energy Resources; Kenneth Payne, Distributed Generation Board; Jason Gifford, Sustainable Energy Advantage, LLC

CERTIFICATE OF SERVICE

I certify that the original and ten copies of this Data Request Response will be hand-delivered to the Public Utilities Commission. In addition, PDF copies of the Data Request Response were served electronically on the entire service list of this Docket. I certify that all of the foregoing was done on January 23, 2018.