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of the Board
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Attn: BPU Docket No. QX23070434

In Response to Notice for Input on the Community Solar Energy Program

BPU Docket Number: QO22030153

The New Jersey Solar Energy Coalition (NJSEC), Coalition for Community Solar Access (CCSA), and Solar Energy Industries Association (SEIA), (collectively referred to as "Solar Parties") appreciate the opportunity to provide our responses to the New Jersey Board of Public Utilities ("Board") Notice seeking input from the public and interested parties on the Community Solar Energy Program ("CSEP") as part of Board Staff's one-year checkup proceeding.

While the first year of the CSEP has been largely successful, the Solar Parties caution against making any disruptive changes to the program until more data points can be ascertained and the implications of the federal elections are realized. The Solar Parties provide responses to each of the questions included in the Notice.

1.What parameters used in the modeling for the ADI Program's one-year refresh differ between community solar projects and projects in the market segments for small and large net-metered non-residential projects located on rooftop, carport, canopy, and floating solar?

The interconnection costs associated with Community Solar projects typically involve larger scale projects in the range of 1 MW or above. These projects, therefore, carry far higher EDC interconnection fees than that of commercial net metered projects which are now tracking at about 50% in the under 1 MW range. Additionally, through the first 5 months of EY2024 the commercial market continues to lag goals running at 59 MWs, likely 30 MWs short of 5 month of goal expectation.

The siting restrictions for Community Solar over net metered small and large almost exclusively require consideration for payment of significant roof top leases due to the scale of these projects. This too creates a significant cost factor over these other market segments.

Clearly, acquisition costs for LMI participants and the need to generate significant discounting

usually far higher than the program required 15% are significantly incremental to the commercial ADI markets, as well. Further, the administrative costs of maintaining the required level of LMI participants and the significant differential in credit risks posed for participants are also of major concern.

Taken together, it is difficult to compare these markets on a project cost comparison, as the Community Solar project cost and financial risk premiums are very different.

2.What cost adjustments should be considered for the community solar market segment?

At this early juncture of the program and until the success of the permanent program can be more accurately assessed, we would recommend that any consideration for altering the incentive levels be delayed for at least another year. In addition, the uncertainty of looming federal policy actions under the new administration could impact the financial viability of Community Solar in areas of the investment tax credit and tariffs placed upon panel imports. It would, therefore, be imprudent at this early stage of the program to make additional alterations in the underlying financials of this program.

3.Are different incentives required for community solar projects located in different EDC territories or with other characteristics?

Due to the vast differences in the EDC's franchise territories associated with load density and geography, in particular, it is not surprising that Atlantic City Electric and Jersey Central Power and Light's interconnection charges are usually far higher than that of PSE&G. However, as stated earlier in these comments, there is not enough data yet available to evaluate the cost impact of these grid system differences to make any meaningful assessments and recommendations.

We believe, therefore, that this issue should be further studied as additional interconnection data is collected and analyzed before making any recommendations in this area of concern.

4.The Inflation Reduction Act increased federal tax credits to 30%, with the possibility for increased incentives for projects using domestic content, projects sited in energy communities, and projects qualifying for the Low-Income Communities Bonus Credit Program. How should these changes be accounted for in modeling incentive requirements for community solar projects?

Without knowing how the incoming administration will propose changes to the Inflation Reduction Act, it is simply impossible to make any assumptions on the impact of these potential increased incentives. However, it is likely that there will be downward pressure and an unravelling of at least some of these provisions.

We would again urge the Board to wait until the smoke clears to make any judgements impacting the current level of incentives, as the unintended consequences of any precipitous modifications to the current program could have disastrous impacts on this important program.

5.Does the pace of registration submission into the CSEP and subscription of the full capacity allocation support a change in incentive level from the initial value of $90 per megawatt-hour?

No.

CSEP provides the opportunity to site projects on properties of scale that are simply unavailable to net metered ADI projects. Naturally, this significant increase in the number of hosting sites will generate a far greater number of project applications. Again, the incremental cost issues associated with Community Solar projects require appropriate levels of incentive for these projects to "pencil out." We do not believe therefore that the subscription rate of interest is based upon the potential for higher project returns, but rather upon the far greater universe of sites available under a "virtual" program.

Further, the significant market response in the first year of the program was, in large part, driven by pent-up demand that had been carried over from projects that were not awarded capacity under the Pilot program as well as new by projects developed in the interim while the permanent program rule process was being conducted. In fact, development is likely to be more challenging and therefore costly going forward, as a result of the lower hanging fruit project sites and available hosting capacity becomes more limited.

Here again, we would caution the Board to not make consequential decisions at this early stage of the program until additional data can be collected and appropriately analyzed.

6.How has the Community Engagement and Subscriber Acquisition Plan influenced project development and enrollment of LMI subscribers?

Thus far, the Subscriber Acquisition Plan has become a far greater and more costly administrative program problem than originally expected. We are, however, hopeful that these issues will ease with the new regulations and the enabling of consolidated billing and self-attestation, as well as in providing municipal "opt-out" alternatives. Again, we will not be able to assess the cost reduction impacts of these new programs until we gain experience and can analyze the cost data.

While it is clearly important to have a robust customer education program in place to ensure transparency and the accountabilities of both parties, with respect to some of the Community Engagement requirements, there have been some challenges with meeting these administrative requirements.

For example, local political and community officials can be reluctant to weigh in without some assurances that the program will be successful and achieve the cost and environmental goals promised. That said, while there could be adjustments to this aspect of the program the Solar Parties do see value in the community engagement and we do not recommend substantive changes at this time.

7.How has the interconnection process influenced project registration and advancement to construction?

The interconnection process has created substantial delays particularly for the Level 3 Community Solar projects exceeding 1 MW in capacity. Level 3 studies have left projects in limbo over many months with no cost information provided to assist developers in determining if these costs can or cannot be carried by the project economics. In many cases the EDCs have then delayed providing accurate final estimates and on some occasions have submitted substantially higher revised estimates well after the project construction has been started. Many of the estimated costs for the smaller >1Mw projects have also been revised jeopardizing those projects as well.

Projects have no avenue open to challenging the cost of the proposed interconnection work, the possibility of finding or even discussing less costly acceptable alternatives as well as obtaining details describing the cost factors involved.

We also understand that all the EDCs include substantial (~20%) contingency fees which are then retained by the EDCs whether or not they have been used to cover actual costs. Due to the proprietary nature of the grid work involved there is no recourse but to accept these estimates without oversight or any ability to challenge these costs. Clearly, there is need for greater transparency and speed in developing interconnection plans and estimates, and some form of oversight. The Board needs to consider these delays in granting extensions for projects that have been delayed due to no fault of their own.

Finally, the "queue squatting" issues need to be resolved. Currently, projects lining up behind others on that same circuit will not even be studied until those projects ahead of them in the queue either move forward or scuttle their project. We believe that projects should be studied quickly, rather than waiting for first project to proceed, and approved projects need to be provided a reasonable time to move forward to construction to unclog the queue. Currently, there are no established time limits to move the process forward.

8.Under existing project development and interconnection processes, how does the project completion deadline of 18 months, or 24 months for projects located on a landfill or contaminated site, with the possibility of a six-month extension affect registration in the CSEP?

These projects need to be judged individually based on their circumstances, which are all unique due to the overlay of environmental requirements and field conditions. Setting targets of 24 months with a six-month extension may work well in normal situations, but the Board should be open to liberally extending those targets as needed through a petition and review process. Given projects on landfills and contaminated sites are in the public interest as the highest and best use for these compromised sites, the Board should take every opportunity to assist these projects in becoming a reality and not focus upon largely meaningless development timelines.

9.What other issues should be considered in the one-year program review?

Based upon the foregoing discussion, we believe that the one-year review should only establish forward looking data collection targets in many of the areas discussed herein so that informed decisions may be made in future reviews.

It would appear very counterproductive to the goals of this important program to make incentive revision judgements based upon modeling that currently cannot reflect the impact of emerging federal policy as well as the interconnection and other cost issues discussed above.

Respectfully submitted,

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