December 16, 2024

Via Email

Sherri Golden
Secretary of the Board
New Jersey Board of Public Utilities
44 South Clinton Ave., 9th Floor
P.O. Box 350
Trenton, NJ 08625-0350

Re: One-Year Checkup – The Community Solar Energy Program ("CSEP")
BPU Docket No. QO22030153
Comments of CS Energy, LLC

Dear Secretary Golden:

Please accept this letter as CS Energy, LLC's ("CS Energy") comments on the Community Solar Energy Program's RFI relating to its one-year checkup. CS Energy is a leading integrated energy company that develops, designs, and builds optimized energy projects in the solar, storage, and emerging energy industries. CS Energy, based in Edison, NJ, has been a leader in the New Jersey solar industry for 18 years and has constructed over 2 GW of solar projects across the Northeast and the United States.

CS Energy has developed and constructed several landfill community solar projects including the 5 MW project on the City of Linden's Landfill and the recently completed 10 MW Berkeley Township Landfill Project, which included the capping of the 40-acre landfill prior to the installation of the solar array. CS Energy's comments are driven by our experience developing and building solar projects in New Jersey and experience participating in the State's Clean Energy Programs.

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?*

   Community solar projects are more heavily impacted by increased interconnection costs relative to net metered projects. In recent years developers are seeing massive increases in interconnections costs. For example, a simple line tap and standard equipment for interconnecting to a 34.5 kV line accounting for inflation used to cost a project in the range of $300k to 500k depending on the site, but recently the EDCs are telling developers that the new normal is in the range of $2MM not including any line extensions or system upgrades. These increases in costs are also being seen on lower voltage interconnections that are more common for CSEP projects. A recent project was told that it would cost a minimum of $3.2MM to interconnection to a 12.47 kV distribution line that didn't require any major upgrades or line extensions. These cost increases are going to create significant barriers for the feasibility of future projects connecting to the distribution systems of the EDCs. Behind the meter projects, such as those in the net-metered sector, require much less extensive interconnection facilities, often connecting to existing infrastructure in a given building, and are less likely to be impacted by these costs seen on front of the meter projects, such as those participating in the CSEP.

   As more projects are accepted to the program and are constructed, the number of potential LMI subscribers is going to decrease as more and more are subscribed to new projects coming online. Depending on the success of automatic enrollment, subscriber acquisition costs are likely to continue to increase. In addition, the varying subscriber discounts available between different projects is likely to lead to subscriber churn when new projects come in offering higher discounts. While it is a positive that subscribers are getting the best available discount, the downside of not having any firm commitments from subscribers is churn resulting in increased programmatic costs to keep projects fully subscribed, relative to behind the meter projects that don't have the subscriber acquisition aspect.

   Community solar projects must also pay market rate lease payments to incentivize land and building owners to move forward with a project. This differs since in a net-metered project the building or landowner is receiving the benefit of the electricity, in a community solar project that benefit from the electricity is going to the subscribers who otherwise can't access solar energy.

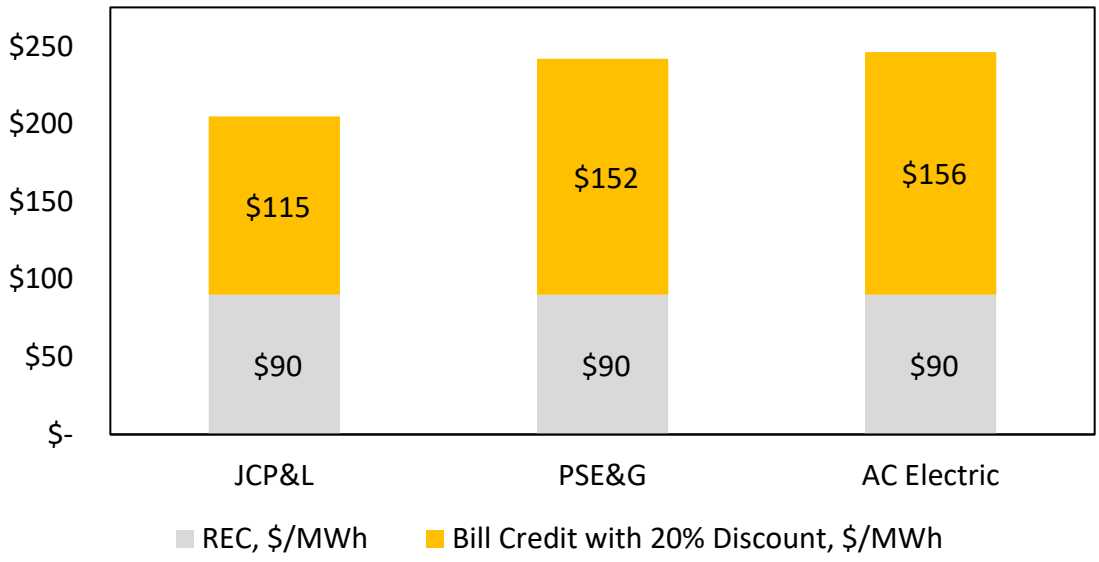
2. *What cost adjustments should be considered for the community solar market segment?*

As mentioned throughout this response, the Board should consider interconnection cost increases, costs associated with interconnection delays, and the impending risk of module tariffs and potential repeal of IRA Investment Tax Credit. At this point, it is unknown what impacts will come from tariffs and the stability of the Investment Tax Credit, so the Board should consider waiting until next year to consider any adjustments within this market segment when the new administration is in place and there is more certainty around these unknowns. The CSEP has proven to be the most successful across the State's clean energy programs and the Board should make every effort to ensure that this doesn't change.

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

The Board should consider different incentives for community solar projects in different EDC territories. There are several components of costs and revenues that could justify the need for varying incentive levels. The first, and easiest to quantify, is that the bill credit received by subscribers is different in each EDC, resulting in variable project revenues across the State. As illustrated in **Figure 1** below, the cost of electricity in JCP&L is significantly lower than that of PSE&G and AC Electric.[1] The total revenue stack in JCP&L is 16% lower than that of the average of the other two EDCs.

Figure 1. Electricity & REC Revenue Stack Per NJ EDC



[1] Community Solar Bill Credits | NJ OCE Web Site

This lower cost of electricity in JCP&L could be the reason why up until recently there was still available capacity in the EDC within the CSEP. The Board should consider increasing the REC in this EDC territory to equalize the total revenue per MWh available to projects.

Interconnection costs and timeframes likely vary across the EDC territories and should be another factor that the Board looks at in determining if different incentive levels are justified. This data is only available anecdotally to individual developers, but the Board should request this data from the utilities or require a public facing interconnection queue posted by the utilities to promote transparency and competition. The timeframe from submission of an interconnection application to receipt of a final engineering study and cost estimate varies between the utilities. The longer this process takes and the more uncertainty surrounding interconnection feasibility there is, the higher it is going to cost developers to finance these projects. Recently, we've seen that owners & operators of CSEP projects are devaluing projects within Atlantic City Electric's territory because of how much uncertainty and dysfunction there is around the interconnection process. In ACE, there have only been two community solar projects that have been successfully constructed evidencing the need for the BPU to act to ensure the success of future projects and the transition to clean energy. The lack of success of projects in ACE is shown in **Table 1** below.[2] Although the utility gets a much smaller allocation of MWs per year, they have only reached commercial operation of 4% of its currently awarded projects. The Board should take this into account when determining if it makes sense to create variable incentive rates across the EDCs. Without action and enforcement of a smooth and efficient interconnection procedure, the Board runs the risk of a community solar dead zone within the State where projects are awarded but will ultimately never get constructed because of the utility's dysfunctional interconnection process.

Table 1. Success Rate of Community Solar Construction in New Jersey EDC Territories

EDC	Awarded, No.	Awarded, MWdc	Constructed, No.	Constructed, MWdc	Success Rate, %
JCP&L	128	195.38	25	48.62	20%
PSE&G	290	403.16	80	110.51	28%
AC Electric	47	81.60	2	2.93	4%
Total	**465**	**680.15**	**107**	**162.05**	**23%**

Further, the respective costs and benefits of the different siting locations of projects should be considered by the Board. CS Energy has been a staunch advocate of reserving a certain percentage of the MW allocation for projects sited on landfills and brownfields. In addition to

[2] Solar Activity Reports | NJ OCE Web Site

creating renewable energy for LMI subscribers, these projects provide extensive public benefits such as putting blighted publicly owned land back to beneficial use in addition to lease payments to municipalities and in some cases capping landfills that have otherwise sat stagnant for years.

If the Board is considering a downward adjustment of the incentive levels, CS Energy strongly encourages the Board keep these incentive levels consistent at their current levels for landfills and brownfield sites, a segment that the Board has prioritized for years and seen great success from.

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?*

   There is significant uncertainty around the future of the investment tax credit as a result of the new administration coming into the White House in 2025. There are a variety of potential outcomes including a full repeal of the Inflation Recovery Act, to removal of Investment Tax Credit Adders, to an accelerated step down of the ITC. We strongly suggest not making any changes to the modeling until mid 2025 when we expect to have more certainty on the outcome of these potential changes. Additionally, the IRA was passed nearly two years ago, and projects currently in the program have been taking advantage of the benefits in the IRA, which have been a major contributing factor to the significant increase in bill credit discounts in the most recent solicitations. We expect that any new modeling the BPU does to lower incentive rates to reflect ITC bonuses will result in lower discounts to rate payers.

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, the pace of registration submission into the CSEP and subscription of full capacity allocation does not support a change in incentive level from the initial value of $90/MWh. The demand for the program was significant during the two pilot years of the program and when the Board cancelled the third pilot year and took several years to release the permanent program after the rulemaking proceedings, there was significant pent-up demand with developers who had fully developed projects that were waiting on CSEP awards and final interconnection approval to start their construction. This pent-up demand and backlog of projects caused a spike in the subscriber discount percentage offered and lead to several solicitations that were fully subscribed. We are now seeing things start to slow down as JCP&L

was not fully subscribed in the initial 10-day window that would have triggered the tie breaker.

The CSEP is still a very young program, and the Board should wait to see how the next several solicitations pan out and the pace that these projects are getting built before deciding if a potential drop in incentive level is warranted. A premature reduction in incentive level could destabilize the market segment and force developers to look at other programs or states.

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

The Community Engagement Plan has required projects to begin conversations with municipalities at earlier stages, which is beneficial, but some requirements, such as the letter of support have the potential to become overly burdensome on projects. Municipalities are usually reluctant to express "support" of a specific project before it has been approved by the planning board. While it is a requirement of the CSEP that a project provide proof of submission to the planning board, it could become a gating item that approval of this submission is required before a town is willing to sign off on a letter of support. While we recommend encouraging local outreach and transparency, we believe the letter of support at that stage of the project can be overly burdensome and once a project receives approval from the planning board, this should be viewed as their "support" of the project.

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

The interconnection process has created significant delays in the construction of awarded projects. PSE&G is still working on the final engineering studies and cost estimates of the projects that were awarded after the December 2023 solicitation. It is now a year into their 18 or 24 month COD deadlines, leaving them 6 months in most cases to complete local building and electrical permits and construction of the projects with no other room for delays. All of these projects will likely require the 6-month extension and likely beyond.

There are several major issues outside of the review times that developers are experiencing. Queue sitting has become a major issue, where a project doesn't have a specific timeframe in which it has to decide on moving forward after receiving final approval from an EDC. This causes projects that likely aren't moving forward to hold capacity on entire circuits over other projects that are ready to move forward. These projects should be required to demonstrate their commitment to moving their project forward (by making good faith deposits to secure

their interconnection position) or be removed from the queue if they do not make the deposit within a reasonable period of time.

The Board should require the EDCs establish a public facing queue similar to how New York State's distributed generation queue[3] operates and create framework similar to NYS Standardized Interconnection Requirements (SIR).[4] This queue equips developers with information to effectively make decisions on moving projects forward depending on what is in the queue on specific circuits and average interconnection costs within the utility. The NY model also creates an efficient queue – allowing good projects to stay in the queue and forcing bad projects out, to make room for more good projects. These processes were implemented through a queue reform in New York several years ago and are a major contributing factor to the success of the New York's community solar market – one of the most robust in the nation.

In the current interconnection landscape in NJ, the hosting capacity maps are not reflective of what is actually in the queue and are only updated once or twice per year based on recent feedback from one of the EDCs. The only way to know if you are in line behind another project is to submit an interconnection application and have the utility tell you that they can't study your project until the other project makes a decision on moving forward. The NYS SIR outlines mandated timeframes for utilities to respond to developers on initial studies, final engineering studies, and keeps developers accountable by mandating timeframes to make decisions on moving projects forward. Recent experience with Atlantic City Electric has left us in the dark on if our project's interconnection study has even started. The Board should consider establishing a similar framework of rules as the number of projects in the State is going to continue to increase, and without a streamlined and efficient process, very few of these projects will reach construction.

[3] National Grid Distributed Generation Queue October 2024 Public

[4] New York State Standardized Interconnection Requirements and Application Process for Systems 5 MW or Less

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?*

   With the current delays in interconnection, there is a lot of uncertainty around the project completion deadlines. Based on recent feedback the projects awarded in the December 2023 solicitation are still being studied by PSE&G, almost a year later, as previously mentioned. It would make sense to tie the start of this COD deadline to the date that a final approval to install is issued by the utility, not the current conditional approval that is provided. This conditional approval doesn't give a developer much insight into what the costs or the timing of the interconnection are going to be. Until the final approval from the utility, projects are stuck waiting until this is received before they can finalize engineering and submit for DCA permitting, which is already a lengthy approval process.

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

   As previously mentioned in prior stakeholder comments, interconnection costs provided in the Conditional Approval approach that the EDCs are taking is coming in significantly higher than where they should be, given the scope of work provided. This leaves the developer with no choice but to move forward with a CSEP application since the EDCs won't move forward on the final engineering study and cost estimate until a project is accepted to the program. This puts developers in the difficult position where they must post escrow on a project that is potentially too expensive to pencil but isn't able to find out unless they get a CSEP award. As such, the CSEP Escrow shouldn't be required to be posted until the EDC provides the final interconnection cost estimate to a developer.

   Similar to how the CSI Program publishes the REC value awarded to successful projects in the competitive solicitation, the BPU should publish the subscriber discount percentages of projects that register into the program. The blind auction approach to the tiebreaker significantly favors larger developers with more projects submitted to a given solicitation.

Respectfully submitted,

John Ervin

VP of Development