Centrica Business Solutions Successor Program Stakeholder Feedback

Overall program design: Staff proposes to establish a bifurcated Solar Successor Incentive Program in which residential projects, community solar projects, and non-residential net metered projects 2 MW or smaller are offered an administratively set $/MWh incentive. All other projects would participate in the competitive solicitation.

1. *Please comment on the benefits and consequences of this suggested division. Does this program design provide a pathway to maximizing solar development while minimizing ratepayer costs and supporting the industry? Please explain and include alternative suggestions if you believe there is a better approach that Staff should consider.*

The 2MW bifurcation should not be used. Instead all net metered projects 5MW AC and below should be part of the administratively set program.

2. *Please comment on the proposed breakdown of market segments in the administratively set program (e.g., net metered residential, net metered non-residential rooftop and canopy, net metered non-residential ground mount, community solar, and LMI community solar). Would you suggest any changes, and if so, why?*

Simply using the same incentive level ("one size fits all") for all projects segments does not account for the difference in cost inherent to these different project types. The utility avoided cost also has a significant impact on the savings and overall economics of a project. As such, there should be a different incentive level for different segments and system types to account for these factors.

The preferences of the state in terms of where to incentivize development should be considered. Rooftops and carports are less invasive compared to ground mounts, therefore there should be a higher incentive value for roofs and carports. Ground mounts should receive a lower incentive value. Residential customers have a much higher utility avoided rate which helps to provide greater savings to those projects, therefore the needed incentive should be lower than that of the commercial incentives.

At the currently proposed $85/MWh is simply far too low for projects to pencil and development in the state will largely come to a halt. Based on project costs and return expectations of financing parties, we recommend a $125/MWh for rooftop and carport projects and a $95/MWh for ground mounts. This seems to be closely aligned with what the Cadmus Capstone Report proposes in the Scenario recommendations (roughly $100-140/MWh). Furthermore, it is worth pointing out that the Cadmus assumption that a 15% discount from the customer's $/kWh avoided cost is significantly underestimated. Instead, we typically must offer a 30-50% discount to customers in order for a customer to consider a PPA. It's important to note that the Cadmus yields for commercial systems were very high compared to what we are seeing the market. All of the Cadmus yields were in the 1300 range, while we are seeing yields much closer to mid or low 1200s. It's also extremely important to note that weather data has been revised down significantly and most financing partners are requiring much more conservative weather data be used when created Helioscope or PVsyst models. In the last year alone we've seen decreases in overall project yields around 6-7%. This has a large impact on project economics and the modeling considerably over estimates system output.

3. *As currently proposed, all net metered projects in the administratively set program would qualify for an incentive of $85/MWh for the first three-year period (EY 2022-2024); community solar*

projects would qualify for an incentive of $70/MWh, and community solar LMI projects would receive an incentive of $90/MWh. Please comment on these proposed incentive levels and if you disagree, please reference specific concerns with the modeling or historic performance assumptions used to develop the proposed levels.

As mentioned above, we recommend a rooftop and carport incentive of $125/MWh and a ground mount incentive of $95/MWh. The community solar incentives of $70/MWh and $90/MWh for LMI projects should be increased to $85/MWh and $$95/MWh respectively. Community solar is a high priority for New Jersey and is a great way to ensure participation in solar, particularly for previously underserved demographics. However, the low bill credit rates specifically for commercial offtakers can make community solar projects difficult to finance. To improve the financial viability and ensure a robust community solar sector in the future, we recommend increasing the REC prices to $85/MWh for the general program and $95/MWh for LMI community solar projects.

4. *The Straw proposes that selected projects would receive a 15-year qualifying life, consistent with the TI Program. Staff seeks comments on whether this is the appropriate term due to the nature of heavily discounting outer-year incentives, as well for consistency with the proposed competitive solicitation program. Please comment on this proposal and explain any alternative suggestions.*

Yes, the 15 year term is appropriate. However, for community solar projects we recommend considering a fixed price REC for years 16-20 even if the price drops to something akin to the PJM Class I pricing, perhaps $15/MWh for years 16-20.

5. *Staff proposes to establish annual capacity allocations for each market segment on an annual basis, as discussed in the Cost Cap section. The annual program capacity allocation would be divided (by four) into a quarterly allocation. Developers would then be able to reserve a spot within each quarter's allocation.*

   a. Staff proposes to allow projects to reserve capacity against the quarterly capacity allocation on a first-come, first-served basis. Please provide any comments on this proposal.
   b. Staff anticipates that there may be situations in which a quarter's allocation becomes over-subscribed. How should the Board handle over-subscription?
   c. What different or additional measures could the Board take to ensure that there is sufficient opportunity to participate in the incentive program throughout the year?

The quarterly allocation can slow down project development as the market has to wait for each round of solicitation. Instead, we recommend using project maturity requirements to prevent an excessively large amount of applicants from applying without having high level of certainty they will ultimately be built. Specifically, we recommend maintaining the requirement to submit an Interconnection Service Agreement from the utility for **all** projects (not just on projects greater than 2MW).

6. *Concern of "ghost projects" or "queue sitting" threatens the productive functioning of the incentive program. Please comment generally on the slate of project maturity requirements as proposed on page 13 of the Successor Straw or suggest alternative bidding requirements, including minimum criteria to demonstrate project maturity, site control, or escrow amounts to discourage speculation.*

As previously mentioned, we believe an Interconnection Service Agreement should be required for **all** projects.

7. *Staff proposes that projects awarded within a quarterly window pay a fee to the program administrator to cover the costs of administering the program. The fee would vary based on project size (under 25 kW, between 25 kW and 500 kW, and over 2 MW). Please comment on what fee should be required for the three project sizes.*

No fees for applications should be used. Instead, we recommend requiring a performance assurance on projects accepted to the program, which would be refundable upon successful completion of the project. We recommend calculating a performance assurance by multiplying $25 per each REC anticipated to be created in Year 1 of system operation, with a max of $75,000. This is equivalent to how Rhode Island calculates their assurances for the Renewable Energy Growth Program and it works very effectively, as it is reasonable, but not too overwhelming. Again, this also helps act as a deterrent against immature projects with low likelihood of being built.

8. Staff proposes that developers seeking an extension beyond the initial 12-month deadline must submit a deposit, refundable upon project completion, equal to 10% of the project cost and not to exceed a value determined with stakeholders. Please comment on how Staff should determine the deposit fee for a deadline extension request.

10% of the project cost is excessively high. We recommend the first 6 month extension should be free. A second six month extension should cost the same as the performance assurance.

9. Staff proposes to set incentives every three years to provide market certainty. However, using an administratively set incentive risks the potential for market under or over performance in any particular sub-market. What measures could be used to stop an overheated market and prevent inefficient use of incentive funds? Should the Board consider implementing measures such as a declining block structure, downward adjustments on the quarterly capacity allocation for the market segment, or others? How should the Board consider and assess market underperformance?

Reviewing the program every two years is a better target. We understand many stakeholders have proposed a yearly review, but this will most certainly be overly burdensome and will also create far too much market uncertainty. It's critical the incentive program not create additional uncertainty in the market. If developers do not have clear visibility into what the incentive pricing will be in 12 months it creates too much uncertainty to develop projects. This is a very important point and while we understand the state believes it is important to ensure the program is correctly calibrated, conducting an annual review will cause far too much uncertainty and the market will stop and start every single year, much like it has done currently. As such, we recommend a two year review rather than a one year review.

10. *What are the benefits and consequences of allowing or prohibiting behind-the-meter projects in non-EDC territories to register in the Successor Program?*

Allowing projects in non-EDC territories is not recommended, as those organizations are not typically equipped to properly handle these types of projects.

27. Should the annual capacity targets for the administratively set program be set broadly for the whole program, or should the administratively set program be further sub-divided into market segments with individual cost caps? In other words, should the Board set cost caps for the residential sector, net metered commercial rooftop, net metered commercial ground-mount, etc., or simply allocate a certain amount of money to the whole net metered program? Staff notes that the community solar segment will have its own cost cap.

The program should keep the amount of funds for all net metered programs. If a subdivision is, created it should just be to exclude residential projects from the rest of the commercial net metered projects.

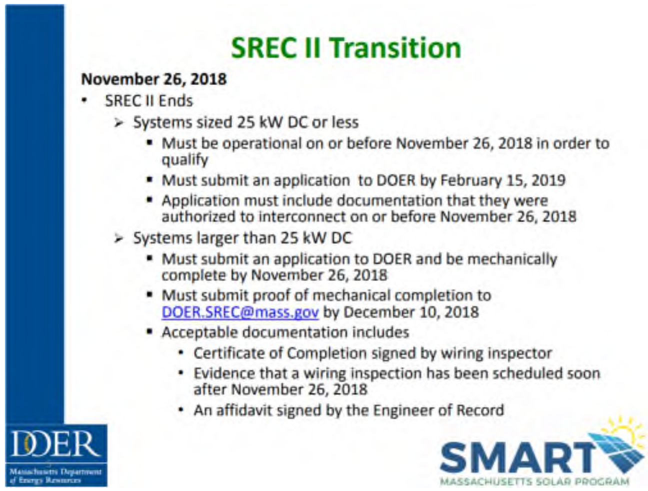
34. Please comment on the Staff proposal that, following the close of this stakeholder process, the Board will issue an Order directing Staff to close the Transition Incentive Program within 30 days. After that 30-day period, the administratively set program will open immediately. The competitive solicitation is targeted to commence in the second half of 2021. Staff notes that there will be a seamless transition for residential, community solar, and net metered projects at 2 MW or less, but there will likely be a gap between the end of the TI Program and the start of the competitive solicitation that will affect large net metered and grid supply projects.

We believe this seems reasonable, as it will give developers time to understand that the transition to the successor program is imminent.

The more important point in the transition to the Successor Program is to ensure that projects that are under development in the TREC Program are able to ensure they receive the TREC incentive and are not at risk of being pushed to the Successor Program because the utility may delay in granting Permission to Operate. This is a fundamental point that we respectfully request the BPU must include in the transition to the Successor Program. Currently, projects that receive a TREC award must complete the installation and receive Permission to Operate from the utility in order to ensure they maintain their TREC status, otherwise they will get pushed into the Successor Program. While we understand the TREC Program was designed to be temporary and must close at some time, the current requirement to provide PTO puts too much control in the hands of the EDCs and places far too much risk on projects that will have been under development for long periods of time. The EDCs are historically slow at working with developers and providing PTO. And there will very likely be a lot of systems reaching PTO at the same time (12 months from the close of the TREC program). Developers must have certainty that projects planned for the TREC program will not be bumped to the Successor Program simply because the EDCs took too long to provide PTO. Receiving PTO can often take 2-3 months and developers who have managed their project timelines effectively should not be at the mercy of the EDC to ensure projects get into the TREC program.

As such, we strongly recommend the BPU consider using Mechanical Completion as the necessary requirement to ensure access into the TREC Program rather than PTO. This is what was done in Massachusetts when the state closed their SREC Program and it worked very effectively. Acceptable documentation to prove mechanical completion included a **Certification of Completion signed by wiring inspector**, evidence that a wiring inspection has been scheduled soon after the target deadline of November 26th 2018, or an affidavit signed by the Engineer of Record. We recommend a Certificate of Completion signed by the wiring inspector be the required documentation for mechanical completion in the TREC Program as it is clear what the requirement is and is easy to provide the certification to the state.

Below are the details on how the closure of the SREC II Program and transition to SMART was handled, illustrating that Certification of Completion signed by wiring inspector was used as the necessary evidence.



35. Should "adders" or "subtractors" be used to further differentiate incentives by project attributes in both the administratively set incentive program and the competitive solicitation, only one program, or neither? Explain why.

If the pricing is segmented by residential, net metered commercial projects in the administratively set program, and then the competitive solicitation and within each of those segments the pricing is calibrated correctly for rooftops, carports, and ground mounts there should be no reason for additional adders. No subtractors should be considered, as they are not necessary.