July 21, 2014

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SoCore Energy and SunEdison's Joint Response to IPA's Request for Comments on Distributed Generation (Issued July 3, 2014)

Please accept these joint comments from SoCore Energy and SunEdison. Our companies are national leaders in the solar industry with development experience in dozens of markets nationwide. We are pleased to offer collective feedback in response to the IPA's July 3rd, 2014 solicitation of comments regarding Distributed Generation. Our responses are generally consistent (with a few modifications) with the commercial/industrial (C&I) program proposal for DG systems >25kW that SoCore presented at the IPA's June 12th DG workshop, key points briefly outlined below. Our comments do not address the <25kW portion of the procurement.

- IPA conducts a competitive procurement for a five year strip of SRECs from qualifying DG projects
- Three-tier procurement: Small systems (<99kW) / Medium systems (100kW-499kW) / Large systems (500kW-2MW)
- $50/kW deposit required with bid. Deposit is refunded if a project is not selected or when the system is energized, but forfeited if the project is selected and later cancelled
- Project must be installed by an Illinois certified DG installer per statute, but the installer need not be selected at the time of bid submission
- Bid certification/site control forms required with bid to demonstrate project viability
- Two-week bid submission window
- Projects not initially selected are placed on a wait list and may be substituted for cancelled projects
- Third-party SREC aggregators may participate but are not required
- Selected projects must be energized by October 31st in the calendar year after contract execution, though extensions may be granted by the IPA

1. For DG between 25 kW and 2 MW in nameplate capacity, should the IPA consider holding procurements for more than one size range category? Are there other attributes that should be considered (e.g., net metering eligibility, community solar projects, residential/non-residential) in determining procurement categories?

There are three distinct segments of the solar market within the 25kW – 2MW range. On the higher end of the spectrum are large C&I rooftop projects and ground-mounts. On the lower end of the spectrum are schools, municipal buildings, smaller industrial and retail projects. It is unlikely that a bid from the smaller market segment could prevail against a bid from a 2MW or even a 500 kW project due to the economies of scale a larger project can obtain. We feel that a three-tiered procurement with capacity subdivided into blocks of 25kW-99kW, 100kW-499kW, and 500kW-2MW would best create apples-to-apples competition and ensure diversity in the types of projects supported by the program.

We recognize that the limited funding available to the IPA for this current procurement may constrict its ability to conduct a three-tier solicitation. If IPA feels that it can deploy funds more efficiently with a two-tier solicitation, we recommend establishing tiers of 25kW-499kW and 500kW-2MW in this procurement only, and moving to a three-tier program for subsequent procurements.

We do not recommend subdivisions based on attributes other than system size.

2. How should the IPA define a distributed generation system? Is size of a system defined at the inverter, at the meter, or in some other way?

The size of the DG system should be defined at the meter. The meter is the point of interconnection between the system and the distribution grid and is the least arbitrary measure of system size. Note – a system may have one central inverter, several dozen string inverters, or hundreds of micro inverters, depending on the technology choices made by the developer. Defining system size at the inverter would arbitrarily limit available choices.

3. If the IPA holds separate procurements for new and existing systems, how should those terms be defined? For example, is a system under development but not in operation at the time of the procurement new or existing? If RECs procured from new systems are anticipated to be of higher value than those from existing systems, what can the IPA consider that will prevent the procurement process from having a short-term impact on project development?

We recommend limiting this procurement to "new" systems, focusing the limited dollars available to catalyze solar projects and economic development that would not have happened but for the procurement. We do not see any benefits to ratepayers or the broader public interest in allocating ratepayer dollars to existing projects that were developed, constructed and paid for without requiring SREC payments as part of the capital stack.

Among other programs, the most common demarcation between "existing" and "new" systems is the opening date of the procurement event. Only projects that were placed into operation after that date qualify as "new" for purposes of program eligibility. We recommend this demarcation because it is the cleanest way to distinguish projects that are incented to move forward because of the procurement and those that would have happened anyway. That said, we recognize that this is the first year of the program and the IPA may want to avoid inadvertently chilling the market prior to the procurement event. Therefore, for this first procurement only, we would support an IPA proposal to draw the line between "new" and "existing" systems on June 30, 2014, the day that Governor Quinn signed HB 2427 authorizing the supplemental procurement.

4. How long and what flexibility should the IPA allow for new systems to commence operation after the procurement event?

Allow systems at least twelve months from the date of *SREC contract execution* for the system to commence operation. There may be a time lag between the procurement event and the contract execution date, and until the contract is executed, developers will generally not begin to procure materials, sign contracts with installation partners, etc. The development timeline for a larger commercial project involves pre-construction approvals (permitting and interconnection) for which turnaround time is largely out of a developer's control. Construction schedules must work around the several months of the year when rooftops are liable to be covered with snow or ice, resulting in costly start-and-stop construction deployment at best or dangerous working conditions at worst.

Ideally, IPA would set the deadline to commence operation at the end of the construction season (e.g. October 31st) in the calendar year following contract execution. That would allow developers to complete pre-construction design, procurement, and approvals over the winter months and preserve a full spring-summer-fall cycle for construction. The IPA should also maintain discretion to grant contract extensions.

5. What are the advantages and disadvantages of REC contracts of five year terms and those of a longer duration? Please be specific by market segment/size, and between new and existing systems.

The price that developers will bid for SREC contracts will be calibrated to close the gap between costs and required revenues in the project's overall financial pro-forma. Whether SREC revenues are stretched out over five years or ten years, they still have to cover the same financial gap. Accordingly, the price *per SREC per year* will be higher for a five year contract and lower for a ten year contract. But because investors and lenders will risk-adjust and discount the real value of SREC revenues in the out-years of a longer-term contract (see Question #8 below), prices bid per SREC will be more efficient in a five year contract versus a ten year contract.

6. What are the trade-offs between contract terms for new systems that pay for RECs as they are delivered versus contract terms that would allow for some upfront payment upon the system going into operation, but with commensurate enhanced credit requirements and clawback provisions?

It is common for C&I solar incentive or SREC programs to be structured via performance-based payments, e.g. SREC payments are made monthly subsequent to delivery. National C&I developers and investors are comfortable with this model. As long as the full term of SREC payments are fully contracted and the counter party is a credit-worthy entity such as the state of Illinois, stretching payments out over a term of five years will not present a barrier to participation. Developers bake adjustments for the time value of money into their bid prices, so in theory bid prices could come back slightly higher if SREC payments are made over time as opposed to upfront, if all else were equal. However, in practice, the cost and complexity of enhanced credit requirements and the perceived risk associated with clawback provisions would likely negate this advantage. The administrative burden of managing ongoing credit accounts on behalf of suppliers in an upfront payment scenario may be onerous as well.

For these reasons, we recommend that the IPA structure the program to pay suppliers for SRECs as they are delivered over a five-year contract term.

7. What elements may be necessary to include in clawback provisions to ensure that Agency, ratepayer, and stakeholder interests are properly protected?

Clawback provisions are not necessary in the scenario in which the IPA is paying for SRECs as they are delivered on an annual basis over a five year contract. In the rare case where a system ceases to perform and generate SRECs, the IPA would simply not pay for SRECs that are not delivered.

8. What are the perceived risks that developers, property owners, lending institutions, utilities, utility ratepayers, and other stakeholders may be exposed to as a consequence of the IPA entering into REC procurement contracts with terms of more than 5 years?

In this procurement, we do not recommend that the IPA enter into SREC procurement contracts for more than five years. Since Illinois has never offered this type of program in the past, developers and lending institutions will price a certain risk premium into the cost of capital issued for participating projects. The longer the contract term, the greater the perceived regulatory and budgetary risk, the higher the cost of capital, the less efficient SREC bid prices will be. The IPA can maximize the efficiency of the use of ratepayer dollars and still accomplish the goals of the DG program by offering five year contracts.

9. What credit requirements may be appropriate for aggregators and other counterparties (i.e., self-aggregating system owners)? Should these requirements vary based on REC portfolio size and system size? If so, how?

We recommend requiring bidders (whether aggregators, developers, or system owners) to submit performance assurance in the form of a deposit of $50/kW, due upon bid submission. Deposits for projects that are not successful in the auction should be returned immediately. If a project is selected, the deposit should be held by the IPA until the project is energized, at which point it should be returned. Deposits for projects that are selected in the auction but ultimately do not move forward should be forfeited.

A deposit of $50/kW is sufficiently expensive to ensure that only real bids for real projects are submitted into the IPA auction, yet not so expensive to discourage participation. Similar performance assurance mechanisms are used in numerous programs around the country to try to discourage auction-distorting bidding behavior. Programs that do not require relatively hefty deposits have been subject to high fall-out rates because developers bid on highly speculative projects, or bid lower prices than the projects ultimately need to move forward. This puts "real" projects with appropriate bids at a disadvantage in the auction and ultimately creates administrative hassles for program managers to backfill the program after projects drop out.

As long as contracts are structured so that payments are made as SRECs are delivered, there would be no significant advantage for the IPA to hold deposits beyond the date on which a project is energized and it starts producing power and SRECs. If, for some reason, the project stops producing and delivering SRECs, the IPA would simply not pay the supplier. In reality, the risk of this happening is extremely small. Once a solar system has been energized, the developer, system owner, and IPA's interests are well-aligned in making sure that the system continues to produce power and SRECs.

10. Are there timing considerations other than those related to DCEO rebates, state and federal tax incentives that the IPA should consider?

Only the weather-related notes regarding construction schedule discussed in Question #4.

11. If aggregators are allowed to bid speculatively (e.g., not all projects in their aggregation identified at the time of bidding), what would be a reasonable length of time for aggregators to be given to provide evidence of viable projects, and what provisions

should be considered to reallocate quantities of RECs to other aggregators if an aggregator is not able to verify progress on project development?

Certainly on the C&I side, we do not recommend that the IPA permit speculative bidding. The budget available to IPA in this procurement is small compared market potential in the C&I space. There are plenty of developers who are willing to do the up-front work to develop real projects with real customers and submit real, competitive bids. Speculative bids will result in auction distortion and increase the likelihood that selected projects will not be completed.

To discourage speculative bidding on the C&I side, we recommend that (a) IPA collect a $50/kW deposit from bidders, due upon bid submission, as discussed in Question #9; and (b) bidders are required to submit site control documentation or a bid certification form that indicates all parties' intent move forward with the project as described should a bid be successful. This could take the form of a non-binding letter-of-intent signed by the developer, system owner, property owner and energy offtaker to avoid parties having to incur legal costs before they know whether their bid has cleared the auction.

12. What additional provisions, if any, should be included to allow entities to be their own aggregator?

None are necessary on the C&I side. We are not aware of a precedent in any other C&I solar market in the country in which an aggregating entity is required to stand between a solar developer and an incentive or SREC contract. Implementing such a requirement in Illinois would impose the unintended consequence of increasing the costs, complexity, and administrative burden of the program for no purpose.

13. Given the framework of the Illinois RPS and provisions of the new Section 1-56(i), what models from other states should the IPA consider? Are there aspects of other state's models that the IPA should be aware of to avoid, and why?

The program that we are recommending for C&I systems is a hybrid with elements modelled after the following programs:

- Connecticut's Medium and Large System ZREC Program
- The New York State Energy Research and Development Authority's (NYSERDA) Competitive Solicitation
- The California Solar Initiative's Performance Based Incentive (PBI) Program
- The Delaware SREC Program
- Oncor (Dallas-area utility) Solar Photovoltaic Program

Our comments generally reflect the good, the bad, and lessons learned that we have observed by participating in these and other solar incentive and SREC programs throughout the country.

14. Should the IPA consider tracking RECs using systems other than PJM-GATS and MRETs?

No. PJM-GATS and MRETs are the only REC tracking mechanism that the IPA should allow.

15. Are there policies and procedures for tracking DG RECs (e.g., system certification) that need updating under current M-RETs and PJM-GATs frameworks?

Not that we are aware of at this time.

16. Participants in our June 12th workshop included project developers, solar installers, both local and national businesses, utilities, trade associations, environmental organizations, consumer advocacy groups, and state agencies. Are there additional entities (or categories of entities) that should be engaged in this process?

This list represents a sufficiently broad cross-section of interested stakeholders.

Thank you for the opportunity to provide this feedback. We are happy to answer any follow-up questions and/or submit supporting documentation upon your request.

Sincerely,

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