July 21, 2014

Anthony Star, Director
Illinois Power Agency
160 North LaSalle Street, Suite C-504
Chicago, IL 60601

Dear Director Star,

Thank you for soliciting comments from the solar industry regarding the upcoming Distributed Generation procurement. Please note the following in response to the IPA's July 3rd, 2014 solicitation. In general our comments and experience relates to systems <2MW and in particular focuses on smaller commercial and residential projects.

ISEA strongly suggests keeping this one-time procurement simple and transparent to ensure the greatest success as well as creating consumer and legislative confidence with the aim of demonstrating a working, long term solution for the RPS program. The successful launch and execution of this program could be used to help craft legislative language for the permanent fix to existing laws and goals for a 25% renewable energy portfolio by 2025.

Questions

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?**

   Given the vast differences in development costs and basic economics for systems between 25kW and 2MW, we recommend that the IPA consider subcategories within this segment.
   - 2MW – 400kW
   - 25kW – 399kW
   - <25kW – multiple procurements with declining

   Although we do not recommend additional attributes for consideration, there may be some value in creating geographic divisions to ensure the entire state benefits from this program, though there should be flexibility if the development of projects naturally seems to be diverse.

   Pricing between each of these categories should be distinct and weighted as the financial needs of each group differs as does the contribution each offers in terms of job creation and economic development to the state. Additionally, ISEA agrees that the <25kW tier incorporate a "declining block" as described in the comments submitted by the ELPC. During the 2012 workshops, it was agreed that a "standard-offer" for residential projects be created as a multiplier from larger commercial scale projects. ISEA recommends this approach is still a valid recommendation.

This approach would need to be transparent to the public and clearly communicated to encourage early adoption of the program with the aim to quickly secure the required volume of SRECs.

Finally, pricing distinctions systems should reflect a higher value for "new" versus "existing" systems in the <25kW category as demonstrated in other state procurement models. This segment would be priced below the lowest "declining block" model as the value to the industry is the lowest having already been built. This is further discussed in Q3 below.

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 system should be measured at the meter or point of interconnection. This will eliminate any confusion that could be construed based on the design elements and inverter selection for the array or any subsequent sub-arrays.

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?**

   As the RPS has been broken for several years and a permanent fix has not yet been established, it is in the opinion of the ISEA and supporting companies that the IPA makes some consideration for "existing" as well as "new" systems. In some instances, existing system owners may have anticipated a working RPS when purchasing their solar installation. Therefore ISEA recommends that "existing" systems be defined as those that were energized between July 1, 2013 – June 30, 2014 (or the equivalent of Energy Year 2014). "New" systems should be defined as those that were energized after July 1, 2014 (or the equivalent of Energy Year 2015). These dates will not have a negative impact or chilling effect on development of "new" projects as the definition of new is effective immediately. We feel it is important that "new" be related more to the passage of HB2427 as opposed to the final definition of both process and terms by the IPA as this is a meaningful indicator to the market that a new policy has been established in IL.

   Existing systems will only receive credit for new generation created during the procurement period as defined by the IPA and older REC's should not be considered as viable for payment.

   All "new" systems should be installed by a qualified and registered DG Certified installer. This requirement would not be applicable for "existing" systems as many may not qualify retroactively.

   Pricing distinctions systems should reflect a higher value for "new" versus "existing" systems as previously referenced in section 1.

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

   Eligible systems should be completed no later than 12 months after the date of the SREC contract. This should allow adequate time for developers to complete the installation. However, possible delays resulting from a variety of legitimate reasons could occur and therefore, applicants should be allowed to apply for a 6 month extension. The extensions would be reviewed by the IPA or by a program administrator and could possibly result in some kind of fee based on the size of the array to encourage completion in the revised time allotment.

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.**

   Answers to this question depends in part on the price of the SREC but in general it is assumed that final pricing will be designed in such a way that it will have a meaningful impact on the project ROI and therefore encourage development of DG assets in Illinois. Assuming the economics to be equal between a 5 year and 10 year term, a 5 year contract would have a marked advantage in terms of financing and market confidence.

   Unfortunately the state of Illinois does not have a strong economic outlook and there may be some hesitation from developers that the state can honor agreements greater than 5 years in duration. Therefore, we recommend shorter contracts that will yield greater market confidence and potentially a stronger ability to achieve program goals.

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?**

   The trade-offs may vary between the size categories for the procurement. The ISEA therefore recommends that systems differ in treatment based on system sizing.
   - 2MW – 400kW – As there could be potential tax implications from revenue resulting in the procurement of SRECs there may be economic benefit to keeping the payments to annual allotments as opposed to an upfront payment.
   - 25kW – 399kW: The same guidelines for larger categories could apply here although it is possible that upfront payments could serve as a financing mechanism that would secure funding for these sized arrays in lieu or in addition to possible grants. Therefore, it is recommended that flexibility be allowed and system owners could choose the payment terms for this category.
   - <25kW: It is likely that this category would have the greatest growth opportunity if allowed upfront payment of SRECs at the time the system was energized. In addition, as the volume of individual contracts in this category will be the greatest, a single upfront procurement would help to lower administrative costs, maximizing the IPA investment in solar assets as opposed to operational fees. Some verification for system performance and SREC calculations based on system parameters should be established from verifiable sources such as NREL or similar forecasting models. These systems are smaller and therefore less of a credit risk individually than larger systems but collectively could have the greatest room for fraud. Therefore it is important to verify system has been installed and is operational. This could be completed by a Third Party Administrator by requiring an executed interconnection or net metering agreement from the utility. Random 3rd party performance verification could be put in place by program administrators to verify systems are operational within the 5 year performance period.

As all systems are required to have an approved inspection by AHJs for utility interconnection, similar requirements could be in place for SREC procurement to help avoid “phantom” systems, ensuring that projects are real and functioning.

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

   Clawback provisions will not be necessary for 400kW and larger tiers if the IPA pays SRECs annually over the 5 year period of the contract. However, clawbacks make be necessary for the remaining two tiers which have the potential for one time upfront payments.

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?**

   There is significant risk on all involved. As stated previously, the State of Illinois does not have a strong economic track record which may create doubt and hesitation in the market, resulting in the need for higher pricing to offset this risk. Therefore, the ISEA recommends that the IPA not enter into agreements that are longer than 5 years in duration. As this is the 1st procurement of its kind, keeping the program both short and simple could be an excellent test for future procurements while minimizing risk to all parties. Many states offered longer commitments in their early procurements only to find that the program required adjustments based on learnings from those early offerings. It is, therefore, in the best interest for the state to use this one-time procurement as a starting point and minimize both regulatory and budgetary risk by offering shorter contracts initially.

   We suggest that the IPA review program design in California, Colorado, New Jersey, and Massachusetts for examples.

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?**

   The ISEA does not recommend using aggregators for this one-time procurement but instead hire a Third Party Administrator (TPA) who would be authorized to enter into contracts on behalf of the IPA and execute the terms and goals of the procurement under IPA guidance and authority. ISEA believes that traditional aggregators, and the subsequent competitive bidding, could create undue confusion and expense during this first SREC offering. A TPA could instead provide a performance bond, ensuring the program expectations are met based on predefined program goals.

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

    ISEA is not aware of timing considerations at this time and does not see a conflict with DCEO rebates, state or federal tax incentives.

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?**

As stated in Q9, ISEA does not see the need for aggregators in this initial one-time procurement. Projects should, as stated previously, be allowed a 12 month compliance to going live with a possible 6 month extension to be reviewed as necessary by the IPA and TPA. A waiting list should be developed within each category and tailored to individual caps as previously defined accordingly. Progress should be verified by proof of an executed interconnection or net metering agreement to reserve a spot in line.

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

The IPA should put in place clear evidence that systems are real, minimizing the risk of phantom projects. Deposits, site control requirements, interconnection proof, etc., are all provisions that will prevent this from happening.

In both categories projects should be given a year to energize with an optional 6 month extension. If projects fail to meet this deadline, the money will be reallocated to participants on a published waiting list.

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?**

Several states have had success in implementing successful SREC programs. Those to consider modeling would include: California, New York, Connecticut and Massachusetts.

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

No, GATS and MRETS should be used to track system performance.

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?**

We are unaware of any policies and procedures that need updating.

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?**

No, ISEA feels that the IPA has done a very good job of including various entities in the industry and cannot recommend any additional stakeholders at this stage.

**The Illinois Solar Energy Association respectfully submits these comments on behalf of the organizations member businesses; including Solar Service, Straight Up Solar and WindSolarUSA who participated in the drafting of this language.**