IPA Requests for Comments: Distributed Generation
Wanxiang New Energy Responses

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?

   Yes, different categories would be appropriate. The financial metrics for successfully funding and constructing a PV Array are quite different from 25kW to 2MW. The per watt first cost for constructing a small system is nearly double that of a large system. Also, consideration should be given to the type of land that is utilized, with priority given to constructing a PV array on otherwise non-productive property.

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 industry standard defines nameplate size of a PV solar system in terms of Kilo-Watts DC. In other words the PV Module Wattage rating multiplied by the number of modules employed. The reasoning behind this is that there are several other mitigated factors such as shadowing, wiring losses, inverter efficiency, and so on, that can be manipulated to determine an AC Nameplate.

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?

   The difficulty in developing market based up-front payments for RECs produced by PV systems stems from the requirement for monthly meter readings. The REC buyer is required to pay their cash out up-front, but takes on the risk that the system owner will continue to ensure meter readings go in every month for many years. Past experience has shown that without the incentive of payment dependent on a meter reading or fixing metering issues, these become a very low priority for a PV system owner and they may take several months or longer to correct them. The potential REC buyer has to price this risk into their offering, making it unattractive to the seller. Because of this risk pricing, much of the benefit gained from forward minting of RECs could be obtained now by simply eliminating the complexity of the Production Tracking System for PV systems and allowing them to use production estimates that don't require monthly meter reading entry, as is currently allowed in states like Maryland, Pennsylvania, and Washington D.C. The current system costs far more in administrative overhead than the questionable benefit it provides over production estimates, and this proposal implicitly endorses the concept of using production estimates. If this is the case, why not eliminate the Production Tracking System now for all PV systems and allow them to use production estimates both in the existing and the new program?

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

   Each system regardless of array size should be certified as "commercially operational" before REC payment occurs.

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.

   PV solar systems have a payback of more than 5 years making it difficult to fund a project without a guaranteed revenue stream that is longer than the payback period. Lenders are looking for developers to have locked in REC strips of 7-10 years.

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 IPA should not partake in prepayment of RECs. There are existing brokers and aggregators and traders who will establish a prepayment or futures market.

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

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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?

   The IPA and the State should regulate volume and Minimum/Maximum price requirements only and should not attempt to regulate the actual price and terms of REC contracts. There are existing brokers and aggregators and traders who will establish a prepayment or futures market, relieving the State and the IPA of administration costs.

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?

Each system regardless of array size should be certified as "commercially operational" before REC payment occurs. There are existing brokers and aggregators and traders who will establish a prepayment or futures market, relieving the State and the IPA of administration costs.

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

    No other considerations at this time.

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?

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

    None, at this time.

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 best REC Markets are based in Massachusetts, Maryland, Washington DC, and New Jersey. To establish a robust Illinois REC market the IPA and State will need to review and adapt several "lessons learned" from other states, with the main points as follows:

    a. Creation of a separate PV solar carve out. There isn't a separate "carve-out" for solar with a higher ACP rate. This means that REC values are much lower than necessary to incentivize the solar market with RECs alone. For comparison New Jersey's RY2012 Solar ACP (SACP) is $658 per SREC.
    b. IPA should determine the Min-Max REC price based on projected supply and demand raising the ACP rate or change the compliance % so both utility types (IU and ARES) participate in the REC market. Currently utility companies may opt to meet their full solar requirement by paying the relatively low ACP fine for not complying, rather than meeting the other "optional" 50 % requirement by paying for RECs.
    c. Require certification of all REC producers and systems as Commercially

Operational (producing power) once their system is officially interconnected with the utility.

d. Do not allow RECs produced outside of Illinois to count towards the Illinois REC market.

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

    No need. Both are the industry standard for REC tracking.

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?

    None that need addressing until a REC market is created in Illinois.

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?

    NONE at this time.