DG Illinois Solar, LLC (Vendor #88) is one of the leading developers of solar under the Illinois Shines Program with four large operating Large DG projects and two operating Traditional Community Solar projects. We also have eight Traditional Community Solar projects in late-stage development / construction (already allocated REC contracts) and dozens of Large DG Projects in late-stage development with plans to submit applications in Q4-2023 and Q1-2024. A number of these projects are in Ameren (Group A), and they represent more than 35 MW+ of Large DG solar capacity, which is more than the entire proposed Group A Large DG program capacity for 2024-2025. These projects have required a considerable amount of effort and time from both DG Solar Illinois, LLC and its customers, including extensive site diligence, zoning permits, interconnection applications/agreements, site control agreements, and PPA negotiations.

For reasons not entirely clear to even us, we have seen considerably more demand for Large DG projects in Ameren than ComEd, despite the fact the projected economic savings to customers in ComEd are generally greater than Ameren. Rather than trying to figure out the various reason why we consistently see more opportunity in Ameren, we would choose to accept it as the current state of the market, **and thereby broadly support any and every proposed method that would allow more Large DG (and Traditional Community Solar) development in Group A**. We have provided more detailed responses to each of the IPA's proposed solutions below.

1. Altering the 30%/70% capacity split between Group A/Group B to feature a greater percentage split to Group A
    a. If this is the only path available to create more capacity in Ameren, then we would support it over nothing. That being said, we would rather see a solution that adds capacity rather than shifts existing capacity.
    b. Addressing the issue of cross-subsidization, we understand the potential concerns, however we are unaware of a specific prohibition against this.

2. Dropping (or reducing) the distinction between Group A and Group B for the Small DG and Large DG blocks
    a. Repeating our above comment, we would first prefer any additive solution to a solution involving reallocation.
    b. That being said, we prefer this solution to solution 1 above as the IPA will simply never be able to correctly anticipate the actual demand in each category (nor should it be expected to). We strongly support any method for allocation of RECs which relies on market demand versus forward projections.
    c. If a pure statewide Large DG allocation is not possible, we would still prefer option 2iii to option 1 as it is a more market-based approach.

3. Increasing overall Program size, thus resulting in larger Group A Small DG and Large DG blocks
    a. We are strongly in favor of the IPA increasing block sizes based on market demand.
    b. The proposed deals and projects that are waiting on program capacity are HIGHLY COMPLEX: requiring long-term engagement, and considerable human and capital investments across dozens of large organizations. Our experience is that "time kills all deals", and customers tend to get "deal fatigue" while waiting for projects to happen. If they form an opinion that the IPA and the state of Illinois don't support these projects either due to lack of program capacity or constantly changing and decreasing REC prices, they may judge that the momentous effort required to make these projects happen is simply no longer worth it. Once these clients walk away from a project, they are not

coming back: that project, those RECs, and those customers are likely gone for the foreseeable future.

    c. In short, we recommend the IPA add more capacity and buy RECs from the projects that are ready now because customers don't typically wait indefinitely.

4. Creating flexibility around capacity allocations with setting aside a specific amount of discretionary capacity
    a. While this is obviously preferable to nothing, and any accretive capacity is preferable to a reallocation of existing capacity; we prefer proposed solution 3 to 4 as we agree solution 4 would create more of a "start and stop" structure than solution 3. We recommend the IPA seek stability and consistency wherever possible.
5. Discontinue the netting of waitlisted capacity against a new Program Year’s block of capacity
    a. This solution may actually be a net negative as it provides no line of sight to when projects may be accepted, versus the current situation where the number of projects on the waitlist can be netted against projected capacity allocations.
    b. Without a waitlist, developers and clients will be left guessing what year their project may get accepted; again we always favor consistency over inconsistency.
6. Adjustment to the prioritizations for uncontracted capacity at close of Program Year
    a. We are fully in favor of this method and would recommend it be applied to Group A Traditional Community Solar as well.
    b. We believe this method can and should be combined with any of proposed solutions 1-4 above.

In summary, we are strongly in favor of any method the IPA can use to allocate more capacity to Large DG in Group A in the near-term. In our opinion, the most immediately effective approach would be to combine proposed solution 3 with solution 6 to allocate RECs to the projects the market has already developed. We would emphasize our belief that many of our currently developed projects awaiting acceptance into the program become infeasible if forced to wait years for capacity with an unknown REC price.

We would also like to address the issue of the currently proposed REC prices for Large DG and TCS. We have more detailed comments to the model below, but first, we would like to confirm the IPA's suspicion that a constantly changing REC price makes it incredibly challenging to develop projects. As mentioned above, DG Illinois Solar, LLC and its clients invest an incredible amount of time and money into preparing projects for submission into the program. We invest these resources completely at our respective risks under the assumption that there will be enough capacity allocated to each category and the REC prices will be consistent and stable. In short, projects currently under development are worth the time and risk under the 2022-2023 REC pricing and will likely be severely challenged with the newly proposed 2023-2024 REC pricing. We would strongly support the IPA introducing some method to ensure REC prices don't change so drastically from plan to plan. The previous program had a 4% step down in price from block to block, and one potential solution could be to introduce a percentage cap (4% is fair and has precedence) between plans as 12-28% changes (as currently proposed) are far too dramatic.

To this end, we have studied the REC pricing model in considerable depth and believe REC prices are being dramatically lowered based on the outlier a year of 2022. The IPA correctly uses the avoided LMPs of energy in PJM and MISO to determine payback thresholds for solar owners and PPA offtakers in Illinois. However, the IPA's model used a 5-year backward look including the year 2022 which saw a historical and anomalous peak in natural gas prices which created a one-time spike in the cost of energy.

As a developer and owner of Large DG systems who sells energy to customers at a fixed PPA price, our customers compare our proposed PPA prices to their view of the cost of energy. We believe large energy buyers are generally not basing their decisions on the year 2022, so we feel the IPA should also remove (or discount) the year 2022's historically high pricing in the REC Pricing Model. By our calculations, the value of the 2023 C&I "Net-Metering Credit" in the model would decrease by $7/MWh in ComEd and $8/MWh in Ameren respectively if the year 2022 was excluded from the calculations.

Even a cursory look at 2023 energy prices shows that LMPs have normalized to pre-2022 values. In sum, a historic and drastic shock to the markets last year drove a shock to LMPs, which has caused the Net-Metering Credit to be inflated and proposed REC prices to be significantly reduced. We believe that it is well within the IPA's rights to adjust the inputs of the model based on a historic one-off event and would caution that the success of the dozens of projects we have in active development (and the jobs and property taxes that go along with them) across the state (both Large DG and TCS) could be at risk if the currently proposed REC prices were to be adopted.

Lastly, we believe we may have found an anomaly in the model itself which is suppressing REC pricing. We would make a major disclaimer that we do not have access to all inputs and may be mistaken in this analysis, but at least wanted to bring it to the IPA's attention. The process for calculating Renewable Energy Credits (RECs) involves determining Net Levelized Cost of Energy (LCOE) in dollars per REC. This is done by dividing the 25-year Revenue Shortfall Net Present Value (NPV) by the 15-year REC Total production (or 20-year REC Total production for community solar projects). The 25-year Revenue Shortfall NPV is the discrepancy between the NPV of required revenue (computed using the CREST model) and the NPV of Net Metering Credit Revenue over 25 years. The 15-year REC total production is the cumulative annual energy production for the first 15 years during which RECs are credited.

The potential issue stems from the fact that LCOE is conventionally defined as the ratio of the present value of total cost over a project's lifetime to the present value of electricity (in this case, RECs) generated over lifetime. In the provided formula, the numerator employs NPV, while the denominator does not, leading to an underestimation of Net LCOE, and consequently, the REC value. In practical terms, this means that the REC Revenue NPV based on the current model's RECs rate falls short of satisfying the Required REC Revenue NPV calculated using the CREST model. Adjusting the model to account for NPV in both the numerator and the denominator would result in a substantially higher REC price.