RESPONSE TO ILLINOIS POWER AGENCY REQUEST FOR COMMENTS ON BEHALF OF THE SOLAR ENERGY INDUSTRIES ASSOCIATION, THE COALITION FOR COMMUNITY SOLAR ACCESS, AND THE ILLINOIS SOLAR ENERGY ASSOCIATION

December 3, 2021

The Solar Energy Industries Association, the Coalition for Community Solar Access, and the Illinois Solar Energy Association (collectively the Joint Solar Parties) appreciate the opportunity to respond to the Illinois Power Agency's most recent solicitation for comments on the REC Pricing Model.

The Joint Solar Parties thank the IPA for the updating of assumptions and inputs. While the CREST model is simply a (highly influential) starting point for REC pricing, the Joint Solar Parties believe that the program is enhanced when the CREST model is producing realistic results based on accurate assumptions.

1. The Agency updated a number of inputs including the level of the federal Investment Tax Credit, updated costs from a national cost benchmarking study, AC/DC ratios based on applications received, current net metering values, and community solar interconnection costs. The Agency would appreciate feedback on those updated input assumptions.

   JSP RESPONSE: Members of the Joint Solar Parties that focus on community solar have the following responses to updated CREST model inputs identified by the IPA applicable to community solar:

Topic	Assumption	Comments
Tax Rate	9.50%	The Joint Solar Parties have no comment
AC/DC Ratio	0.69	The Joint Solar Parties believe this is an acceptable assumption for systems that do not have DC-coupled storage
Capacity Factor	17.79%	The Joint Solar Parties note that this seems high for a fixed-tilt system; a lower percentage that is more typical or closer to average would be appropriate.
Project Useful Life (Years)	25	The Joint Solar Parties note that actual useful life may vary but many community solar systems have a longer timeframe
Property Taxes ($/MWac-yr)	$6,000	In the experience of the Joint Solar Parties, the mill rates in ComEd territory tend to be slightly higher than Ameren.
Land Lease ($/acre/year)	1000	The Joint Solar Parties believe this value is acceptable, but note that in members' experience as reported anecdotally to the Joint Solar Parties, land lease rates typically increase each year by 1.5 to 4 percent.
Acres/MWdc	5	The Joint Solar Parties believe this estimate is acceptable.
Interconnection ($/Wdc)	$0.15	This input is acceptable for Ameren but is very low for ComEd. While actual costs are not always the same as non-binding estimates, typical non-binding estimates (even

Topic	Assumption	Comments
		if only looking at projects that go forward) are far higher on average in the experience of the Joint Solar Parties members in ComEd than Ameren. The Joint Solar Parties suggest at least $0.30/Wac (converted to AC with whatever conversion factor the IPA chooses) for ComEd—while many systems are higher, this is the threshold for triggering the partial collateral recovery by the Approved Vendor.
Generation Equipment ($/Wdc)	$0.88	The Joint Solar Parties note that this may have been an accurate assumption a few years ago, but does not reflect tariffs on panels or scarcity/supply chain issues that have been ongoing since not long after the COVID-19 began
Balance of Plant ($/Wdc)	$0.32	The Joint Solar Parties note that while this may have been an accurate assumption a few years ago, it does not reflect increases in 2021 alone due primarily to supply chain issues and material shortages.
Total EPC ($/Wdc)	$1.20	The Joint Solar Parties believe this value is quite low, even before taking into account prevailing wage or additional costs related to integrating new EEC contractors or subcontractors. As noted above, the procurement piece of EPC has increased EPC prices further. For competitive reasons, the Joint Solar Parties members are not comfortable providing EPC costs even anonymously for these comments through the Joint Solar Parties but the feedback is that these prices underestimate even the pre-Public Act 102-0662 status quo. While the Joint Solar Parties have anecdotally heard of numbers up to $2.00 $/Wdc in the current market, at least a 20% increase, while still underestimating current conditions with prevailing wage, comes far closer.
Annual Reduction in Installed Costs (%)	4%	The Joint Solar Parties note that while this assumption may have tracked previous trends in reduction in equipment pricing, equipment (as noted above) is currently well above where it has been and wages increase in absolute terms every year in addition to new prevailing wage requirements.
Subscriber Savings (%)	20%	The Joint Solar Parties understand that there are a range of products in the market but this is a reasonable estimate for retained customer value as a percentage of community solar bill credits.
Asset Management ($/MWcd)	5000	The Joint Solar Parties note these costs are very low for Illinois, primarily though not exclusively because of the cost of addressing customer churn.
O&M Expense, Yr 1 ($/MWdc)	1000	The Joint Solar Parties member companies providing feedback had a range of opinions from this value being roughly accurate to being far below market.

The Joint Solar Parties wish to stress that any system-specific assumptions (including all but perhaps tax rate) are not necessarily applicable to behind-the-meter systems of any size. However, general trends with installation costs, wages (residential systems are exempt from prevailing wage but not general wage pressures) and component/EPC costs are impacting behind-the-meter systems as well. The Joint Solar Parties addressed these issues in greater depth in comments related to block reopening, including Large DG non-waitlisted pricing.

As also noted in comments related to block reopening, the cost of prevailing wage is not universal across all counties. The Joint Solar Parties continue to recommend an approach where systems in higher-prevailing wage counties receive an additional adder. The Joint Solar Parties wish to avoid a situation where there is a strong economic disincentive to build in higher-prevailing wage counties. Such a disincentive is contrary to the statutory goals of geographic diversity of projects and of accelerating the solar economy across the entire state.

In addition, any REC Contracts that are paid as delivered or paid on a less accelerated basis should take into account the reduced Net Present Value of REC payments—especially given high discount rates during an expanding economy.

2. The updated REC Pricing Model used updated capacity factors that varied by project type and group and were based on an analysis of project applications received by date. Are these capacity factors appropriate?

   JSP RESPONSE: The Joint Solar Parties confirm that the updated capacity factors are in line with what the Joint Solar Parties expected, with the exception that community solar appears to assume single axis trackers with the capacity factor but O&M and EPC that is more in line with fixed tilt. The Joint Solar Parties also recommend that the IPA publish a table with standard capacity factors (used for REC pricing) in a similar manner as it publishes block pricing, so that Approved Vendors and their vendors can easily identify and use those values as a target system capacity factor if they so choose on a voluntary basis.

3. Due to the lack of data from existing applications for smaller sized community solar projects, data from distributed generation project capacity factors were used as a proxy for the likelihood of these projects to be roof mounted and thus less likely to use trackers. Is this a reasonable proxy for smaller community-driven community solar projects?

   JSP RESPONSE: The Joint Solar Parties agree that this is a reasonable proxy for smaller community-driven community solar projects, particularly those in urban and suburban areas that may end up being located on rooftops or otherwise subject to layout or equipment constraints similar to rooftop projects.

4. The Agency updated interconnection costs for community solar projects based on a survey of community solar projects currently accepted in the program. Are these updated costs accurate?

   JSP RESPONSE: The Joint Solar Parties agree that the updated interconnection costs for community solar are much more accurate. The Joint Solar Parties are unsure what interconnection costs—especially in ComEd—will look like as the program continues to expand and substations with capacity available today are eventually filled and the "low hanging fruit" substations are eventually filled. For community solar in particular, an assumption of $0.30/Wac (converted, of course, to $/Wdc using the AC/DC assumed conversion factor in the model) is probably more accurate for ComEd, given that to the Joint Solar Parties' anecdotal knowledge many systems went forward with higher interconnection costs but that value is the cutoff for retaining some collateral in the event of termination before Energization.

The Joint Solar Parties note that upgrade costs continue to increase for a variety of reasons: increased commodity prices, increase labor costs, and the amount of indirect utility costs being charged to the Interconnection Customer. While the Joint Solar Parties note that anecdotally some projects have had actual costs under non-binding cost estimates, current interconnection estimates (especially with procurement of long lead time items) are going up as a general matter for those systems that require an upgrade.

5. The Agency was also interested in feedback on inputs that were not updated including those related to financing structure (e.g., debt ratios and project financing interest rates), internal rates of return, and O&M costs.

   JSP RESPONSE: Until now, payments under the ABP REC Contract were made 20% at energization and 5% each for the following 16 full quarters. Following Public Act 102-0662, payments for RECs for community solar and Public School projects are made over a 20-year period without acceleration and Large DG projects are paid on an accelerated (but less accelerated than before) basis. The decrease in net present value of the payments—because the payments are made further in the future and thus more heavily discounted for their current value—is substantial. The IPA's CREST pricing model is equipped to address impacts to net present value, with the inclusion of an 8.67% discount rate to cash flows over the life of the system. The IPA divides the NPV revenue shortfall by nominal REC production to derive the REC price. The Joint Solar Parties note that according to calculations run by CCSA (which can be provided upon request), community solar REC value would have to be increased by 37% based on the discount rate assumptions in order to maintain the same net present value given the deceleration of payments.

   The Joint Solar Parties also note that the discount rate of customer acquisition costs was assumed to be 6% even though the revenue discount rate was assumed to be 8.67%. The Joint Solar Parties suggest making the discount rates consistent.

   The Joint Solar Parties further note that the Joint Solar Parties anticipated the solar cliff and the possibility of REC Contract payments not being made on time and in full may have changed the viewpoint of financing parties on the Illinois programs including the Adjustable Block Program. The Joint Solar Parties have not received quantified information but expect at best a neutral and potentially a negative impact on financing terms.

For more details on those feedback topics see pages 143-8 of the withdrawn draft Second Revised Long-Term Plan.

With the enactment of Public Act 102-0662, the Agency is also interested in feedback on the following topics:

6. With the increase in Small DG to up to 25 kW, should there be a single Small DG price for each Group, or should there be size categories like there are for Large DG and community solar (e.g., an up to 10 kW price and a over 10 kW to 25 kW price)?

   JSP RESPONSE: The Joint Solar Parties recommend that the price should be the same for all systems under 25kW. For Large DG projects, the Joint Solar Parties recommend that the IPA keep sub-categories. However, given the increase in maximum project size to 5MW, the Joint Solar Parties suggest a category for 25-100KW to differentiate the smaller Large DG systems.

7. With the expansion of maximum project size to 5 MW, what additional price categories should be added for projects over 2 MW? Is one category for 2 MW to 5 MW projects sufficient?

   JSP RESPONSE: The Joint Solar Parties agree that one category is sufficient for 2 MW to 5MW projects.

8. Should changes to the Illinois net metering statute inform the REC pricing model's assumptions for revenues that a project receives from net metering? If so, how should the model address those changes?

   JSP RESPONSE: Yes, to the extent that changes are expected to impact revenue. For instance, the Joint Solar Parties agree it is fair to assume transmission will be included in community solar bill credits (although continue to disagree with use of an escalator for bill credit rates over time because that is not how the Price to Compare has changed over recent years). For behind-the-meter systems in particular, the changes to credit value are more limited and if anything the changes in law mostly ensure that there are fewer hidden losses to net metering credits assumed by the CREST model (for instance because a customer changes suppliers and must reapply for net metering/lose their banked credits).

   As a related matter, the Joint Solar Parties understand that some municipal utilities and rural electric coops continue to refuse to allow third-party ownership structures, contending that such an approach violates their exclusive right to sell energy to customers. While the Joint Solar Parties strongly disagree with that characterization, projects looking to take advantage of net metering in those territories (unless or until there is a change) will be forced into the model of selling the system to the customer, which is a great option for some customers but not right for every customer.
9. The Agency previously issued a request for stakeholder feedback on the cost of compliance with prevailing wage requirements as part of the Adjustable Block opening process. Are there other significant cost adjustments that should be considered that were not reflected?

JSP RESPONSE: The Joint Solar Parties reiterate their comments regarding the Net Present Value impact of pushing REC payments out to 20 years of non-accelerated payments for community solar and all Public Schools projects.

Also, the Joint Solar Parties suggest an added bonus to working with contractors participating in a Department of Labor registered apprenticeship program. Working with contractors that engage in collective bargaining with their employees is consistent with important goals of Public Act 102-0662.

10. What additional cost considerations should be included for public schools, community-driven community solar, and EEC projects? Should any of these be adders rather than adjustments to the base REC price (e.g., an adder for rooftop community driven community solar projects)?

    JSP RESPONSE: Equity Eligible Contractors acting as Approved Vendors in the Equity Block will face several costs as they expand into Solar and choose to participate in the Adjustable Block Program. Some of those costs include, but are not limited to, up-front costs related to hiring, personnel, materials, equipment, legal, and marketing. For instance, a new Equity Eligible Contractor may not have a form PPA/subscription, a form lease, or other key documents, and may incur costs seeking to identify vendors (insurance providers, third-party sales agents, an installer, etc.). The Joint Solar Parties suggest that there should be adders within the Equity Block to encourage and support participation of Equity Eligible Contractors that are newly formed. Alternatively, the IPA could devote a separate amount to the pre-Energization payment—while it could be accounted for as part of the REC price, it would be a maximum accelerated payment if certain prerequisites were met (such as a maximum 10 MW of solar projects developed).

    For Public Schools, roof replacement is likely going to be an issue for many Tier 1 and Tier 2 schools. That will have a cost that may be taken on in part or in whole by the Approved Vendor and financed through a PPA price.

    Community-driven community solar should be priced separately based on the unique costs, with adders for voluntary commitments (such as local subscribers) that earn additional points in the scoring rubric. Please see the response to Question 11 below.

11. Community Solar REC prices currently include an adder for small subscriber commitments with the highest adder for projects with over 50% small subscribers. With a 50% minimum commitment for small subscribers not a statutory provision, should the small subscriber adder be removed and instead subscriber management costs be factored into baseline community solar prices?

    JSP RESPONSE: The Joint Solar Parties support reflecting the adder (i.e. the increased costs of acquisition) in the base REC price because 50% small subscribers are now required (and the draft REC Contract zeroes out payment if Subscription Mix is measured below that level). Thus, the costs of small subscriber acquisition and retention for 50% of Actual

Nameplate Capacity should be included in the base REC price. The only reason to have an adder is if the IPA decides to offer an enhanced (i.e. 75%) small subscriber tier as it did initially. The Joint Solar Parties support a 75% or above small subscriber incentive.

Responding further, the Joint Solar Parties recommend the IPA solicit information directly from owner/operators about their subscription acquisition costs to respond on a voluntary basis. As the program expands, the Joint Solar Parties anticipate that acquisition costs will be higher as the most eager potential customers are increasingly identified and enrolled.

12. What price adjustments should be offered for community-driven community solar projects to cover potentially less economically efficient approaches to subscriber acquisition, subscriber management, project location, and other criteria for project selection?

    JSP RESPONSE: The Joint Solar Parties note that a number of the proposed adjustments to community-driven community solar can add considerable costs and risk to a project and thus should be compensated with an increased REC value. The Joint Solar Parties wish to emphasize that the risk of subscription level maintenance (i.e. that the system will be subscribed in a way that leads to less than the maximum available payment being made) is likely to be reflected in financing cost/reduced tax equity investor payment. This is not a direct "cost" as reported in the CREST model, but it does indirectly impact other costs and revenues tracked by the CREST model.

13. How will the option for utility-billing for community solar subscription fees impact subscriber management costs?

    JSP RESPONSE: The Joint Solar Parties note that pursuant to changes in Public Act 102-0662, the utility is capped in how much it can charge for net crediting. While the Joint Solar Parties will reserve judgment (and recommend that the IPA similarly reserve judgment) until the tariffs are released and actual pricing structure can be confirmed in addition to other pertinent terms and conditions, the Joint Solar Parties believe it is reasonable to assume that the fees associated with utility net crediting are a baseline for billing and collection cost. As an example of pertinent terms and conditions: the payment timeframe and whether payment is subject to any reserves, delays, partial payments, or other terms. In ICC Docket No. 19-1121, the Joint Solar Parties actively opposed ComEd's proposed billing and collection service in large part because it was (to summarize) "pay when paid" which places all of the risk of collection on the owner/operator.

    However, to be clear, the Joint Solar Parties do not expect the costs of utility billing to be the only costs related to subscriber management costs even as they relate to billing and collection, because the Approved Vendor/subscription manager will still play an active role in QA/QC (which has been a significant issue for placement of credits on customer bills), customer management, and filling in the gaps where the utility does not act (for instance, billing and collecting from customers whose credit appears on an ARES bill)—to say nothing of customer care, churn management, mandatory reporting, and other related matters.