Chapter 7

JSP INTRODUCTORY STATEMENT: The Joint Solar Parties appreciate that through this request for comments the IPA is seeking feedback to many changes to the ABP. While the Joint Solar Parties attempted to address the benefits and challenges of each as identified by the Joint Solar Parties, the Joint Solar Parties note that overarching all comments is the consideration of prioritization of the Program Administrator's resources. Given that there remain substantial delays in application review across the board—some of which have improved—persistent challenges with the Standard Disclosure Form, ongoing issues with providing accurate and actionable guidance on program ambiguities, and other core functions, the Joint Solar Parties recommend evaluating in addition to other factors the extent to which changes will impact the Program Administrator's ability to continue work on core functions and implement any changes.

TOPIC 1: Expansion Pricing Resulting in Negative Incentives Levels

Questions

1. Is this REC price blending approach (blending of the old REC price with expansion REC price) an effective methodology for system expansions? What incentivizes expansions to already existing projects from a REC pricing perspective?

JSP RESPONSE: While the Joint Solar Parties are not sure how often expansion comes up, negative REC pricing is a substantial disincentive. A better approach is to have the original REC payment stay as is and the marginal RECs be paid at the rate for the total system provided that the original system has Energized. In other words, if the original project was 400 kW in Block 1 (from 2019) and the expansion brought it to 650 kW in 2023-24, the original RECs should be left undisturbed and the expanded RECs should be paid under a new product order at the 500-1,000 kW price. This would prevent surreptitious gaming of expansions through economies of scale but still allows a willing customer to see benefits from additional generation.

2. Are there models in other states that have been successful for the pricing of expansions that the Program can review?

3. Would the absence of incentives for expansions have a negative effect on the development of expansions?

JSP RESPONSE: Yes. As the CREST model demonstrates, without incentives there is a revenue gap for all types of systems under the conditions modeled.

TOPIC 2: CS Small Subscriber Limit at 25kW Across All Projects in the Program

Questions

1. What are other ways that the IPA can ensure compliance with the statute?

JSP RESPONSE: The Joint Solar Parties dispute the premise of this question. The statutory language is straightforward: a single account may not have a subscription or subscriptions in aggregate of greater than 25 kW to a single community solar project. That is easy to monitor by comparing subscribers claimed by that system. Having more than 25 kW in subscriptions across multiple community solar projects so long as a subscriber has no more than 25 kW in subscriptions to a single community solar project is permitted by statute. The proposal addresses a statutory requirement that does not exist and is not supported by statutory language. As the Joint Solar Parties explained extensively in comments on the Program Guidebook, the statutory language is clear that the evaluation is on the basis of subscriptions "to the facility's nameplate capacity" (emphasis added) and is silent about the total subscriptions held by the customer across multiple community solar projects.

The Joint Solar Parties also note that the IPA has not ever to the Joint Solar Parties' knowledge either stated or enforced a requirement that a small subscriber only hold 25 kW of total subscriptions across multiple systems. The Joint Solar Parties understand that multiple subscribers for multiple projects across many sectors (commercial, government, and residential) have multiple subscriptions totaling greater than 25 kW and that this was allowed by the previous Program Administrator.

2. What challenges do AVs and Designees face in determining whether a single utility account sums to over 25kW across the Program, to ensure the customer would be considered a small subscriber? Please explain in detail so the Agency might understand how to address these challenges.

JSP RESPONSE: The Joint Solar Parties are unaware of any method to determine whether a subscriber currently has other subscriptions other than disclosure by the subscriber or review of a utility bill that shows the other subscription. Once again, however, the question of whether the subscriber has any amount of other subscriptions is not relevant to the statutory test and the IPA has provided no reason why having a single customer with subscriptions in multiple projects of 25 kW or less to each such project is contrary to the statutory language.

3. What information can the customer's distribution utility provide back to Avs and Designees through their community solar portal or other means to identify whether the customer already has one or more community solar subscriptions?

JSP RESPONSE: This information is irrelevant because there is no basis in statute for limiting the number of community solar subscriptions a "small subscriber" may have, as long as a designated "small subscriber" holds no more than 25 kW of subscriptions to any single facility.

TOPIC 3: Developer Cap

Questions

1. Would the Program benefit from a developer cap in other categories? If so, what is an appropriate level? 20% has been used throughout the Program's history, but the Agency is open to feedback on a different percentage is supported by appropriate justification.

JSP RESPONSE: The Joint Solar Parties support a 20% developer cap for categories that both fill quickly (within one to two months of annual block opening) and that have multiple participating Approved Vendors. For instance, Small DG has filled historically, but only over time. Implementing a developer cap in Small DG, which has systems submitted throughout a year would be administratively burdensome and problematic to track percentages throughout the year—especially for Approved Vendors that aggregate over multiple dealers or installers. Such dealers or installers within an aggregated group would be unpredictably limited by the number of projects submitted by other dealers and installers within the aggregated group, leaving them and their customers in an untenable situation because they could not know if or when block capacity is no longer available to them. On the other hand, TCS and the community solar portion of the EEC Block (since community solar was added) have regularly reached capacity and have had many participants. CDCS has filled but with a more limited number of participants that would have led the program to be well underfilled if there was a developer cap. Public Schools and Group B Large DG have not recently sold out.

2. How might a developer cap work in a category with rolling application submissions (i.e., no distinct window for submissions)?

JSP RESPONSE: While the Joint Solar Parties (like the IPA) did not support the Commission's ultimate decision to only impose a developer cap on the EEC Block for 2023-24 if all capacity was filled on the first day, the Joint Solar Parties oppose and urge the exercise of caution with imposing developer caps in other blocks where capacity is not immediately filled (defined for these purposes as 1-2 months after annual block opening). That said, to the extent that the LTRRPP imposes a developer cap in a block that does not immediately fill (and thus has rolling applications), the developer cap should be tracked with each submission. Once an Approved Vendor hits its cap, its submissions should go to the waitlist (subject to the waitlist approach approved in conjunction in the LTRRPP) rather than be immediately approved. The Joint Solar Parties believe that a developer cap in a block that does not immediately fill will create more administration burden, market confusion and processing delays, not only for developers but also, importantly, to would-be consumer participants in the ABP. In particular, the Joint Solar Parties oppose Small DG developer caps.

3. Are different percentage levels appropriate for different Program categories? If so, please explain why.

JSP RESPONSE: The Joint Solar Parties recommend that the IPA remain mindful of categories in Group where 20% of capacity allocations are smaller than typically-sized projects for that category.

4. How should the developer cap be administered Program-wide? Should developer caps be applied across both Groups A and B for a single category or should the developer caps be limited within a Group/category combination?

JSP RESPONSE: To the extent that developer caps are applicable (i.e. to those groups within blocks that have filled quickly) the Joint Solar Parties support developer caps at the group within a category level.

TOPIC 4: Closing of Program year Before May 31st Each Year

Questions

1. What is the impact to AVs and Designees if the program year closes before May 31st?

JSP RESPONSE: As an initial matter, the Commission found in approving the LTRRPP in ICC Docket No. 22-0231 that "The Commission notes that the IPA clarified its intent to maintain a continuously open waitlist. No party seems to dispute this proposal and the Commission agrees that it is appropriate." (Final Order dated July 14, 2022 at 59.) The Joint Solar Parties strongly support continuously open waitlists, which is not possible if the waitlists are closed for a period of time. Each time the ability to apply to the program is paused and waitlists are closed for a period, the idea of first-come/first served fairness is compromised. Projects that become ready to apply to the program during the pause are harmed relative to projects that can take advantage of waitlists becoming static to allow a longer project development timeline.

To the extent that the blocks must be closed, at minimum the program should allow new applications to be received during the closure period and to have their timing recorded for first-come/first served ordering currently imposed in some categories and that may be imposed on others in the future. In addition, for systems with shorter sales and development cycles such as Small DG, continuous ability for applications to be submitted and reviewed better ensures good customer outcomes and avoids surges in applications.

2. What do other annual incentive solar programs do in terms of program opening and closing timelines?

JSP RESPONSE: For similar programs with which the Joint Solar Parties are familiar, there is no gap between program years.

3. What amount of time between the close of one Program year to the opening of the next Program year would ensure the best administration possible while causing minimal disruption to Program participants?

JSP RESPONSE: Consistent with annual programs in other states (except to the extent programs close due to lack of capacity, such as California's SGIP) there should be no gap.

4. Alternatively, would it be best to close the Program on May 31st and then reopen the Program sometime after June 1st? If so, what period of time would ensure the best administration possible while causing minimal disruption to Program participants?

JSP RESPONSE: The same issues are present and the Joint Solar Parties still urge that during closure applications still be received and time-stamped for first-come/first-served purposes.

TOPIC 5: Further Differentiation Between EEC projects

Questions

1. Do stakeholders see a need for a process that further differentiates between projects within the EEC category? If so, please provide details as to why such differentiation is needed.

JSP RESPONSE: The Joint Solar Parties believe that much of the overcapacity will be resolved by (1) imposition of a developer cap and (2) considering two EECs that share one or more common EEP(s) to be "affiliated" for the purposes of the developer cap.

However, to the extent that further differentiation is necessary, the Joint Solar Parties recommend project readiness criteria be applied for community solar. The Joint Solar Parties recommend that the presence of a signed interconnection agreement be the first tiebreaker, followed by the date of the land use permit, the site control document, and (if applicable) the date of the interconnection agreement as the secondary tiebreaker.

The Joint Solar Parties strongly support the continued absence of a scoring system. The scoring system risks long-term development investments made by EECs that are rendered useless by a scoring system that values characteristics unknown at the time of development.

2. If there is a need, what process might accomplish the goal of differentiation best? Please include details on the process, how it would work, and the intended end result that the process would produce.

JSP RESPONSE: Please see above.

3. What are ways that Program design can incentivize further differentiation between EEC projects?

JSP RESPONSE: The potential to be selected above other competing projects is a sufficiently strong incentive. The Joint Solar Parties caution against imposing additional burdens on the EEC Block, which will only push the block further toward established developers and away from small or emerging businesses that are less likely to be able to respond quickly (or at all) to the increased complication and cost.

4. What are other mechanisms that have proven to be effective for project differentiation in other markets/programs/etc.?

JSP RESPONSE: The Joint Solar Parties are not aware of a program equivalent to the EEC Block in other states; other approaches to differentiation are not specific to that segment.

TOPIC 6: Public Schools Category Uptake

Questions

1. Are there modifications to the requirements for this category that can be considered that would incentivize additional development in the Public Schools category?

JSP RESPONSE: In the experience of the members of the Joint Solar Parties, projects on public schools have long been considered for the ABP and have had some historic success prior to the Public School Block. However, while the Joint Solar Parties have not conducted a comprehensive study, the Joint Solar Parties suspect that two factors are largely in play. First are the general speed of school procurement, which tends to be more deliberative than even other units of government (much less the private sector). That longer sales cycle is not a problem *per se*, but it does explain the slower uptake. Second are programmatic reasons, such as the reversal on allowing community solar on property adjacent to school property, potential penalties if the school or school district no longer owns the site, or other program restrictions that add risk or cost or narrow opportunities compared to placing the same system in Large DG or TCS categories. Third is an inability to backfill changes to the anchor subscription with subscriptions by other school districts.

For larger systems like Large DG or TCS, the ability of developers to utilize sufficient land owned by school districts but not already earmarked for some future use may be quite limited. Many school districts may see value in being an anchor tenant of a community solar project, but that perceived value is erased once they realize they are required to lease out school district-owned land far out into the future, inhibiting development of school buildings and other facilities that benefit students, as well as inhibiting the sale of the land to residential developers to eventually facilitate a larger student population.

2. Are additional provisions needed to preserve (i.e., rollover) capacity in this category in future years? If yes, please explain why and the provisions that the Agency should utilize to increase participation in this category.

JSP RESPONSE: A structural fix to streamline the process and reduce risk for schools would be more helpful than preserving rollover capacity. For instance, the case-by-case review of what happens when a school building is vacated introduces substantial risk over 20+ years for both behind-the-meter and community solar projects.

3. What unique barriers to development of distributed generation projects on Public Schools are being encountered by AVs and Designees? How can the Agency address those barriers in order to increase participation in this category? Are there structural barriers to participation in the category that the Agency can address through the Long-Term Plan?

JSP RESPONSE: Please see above.

TOPIC 7: DC/AC Ratio & Other Requirements for Projects with Storage

Questions

1. Is a different DC/AC ratio more appropriate for distributed generation systems paired with storage and, if so, why? Please provide technical analysis supporting your position or studies/research that can be referenced.

JSP RESPONSE: The Joint Solar Parties support having no cap on DC/AC ratio, because ultimately the AC capacity factor and total RECs will be an obligation of the generation (and storage) system. Each Approved Vendor will have its own viewpoint about the economics of

round-trip losses, the viability of batteries to address clipping vs. batteries to deploy substantially in peak hours (4-8 p.m.) , and what ideal DC/AC ratio supports project economics allowing the production value of batteries to sufficiently outweigh the costs. Pairing storage with DG photovoltaic systems on the DC side of the inverter can allow clean energy to be dispatched at the maximum inverter limit for longer into the evening, even after the sun sets. This can provide significant peak load reduction benefits for the distribution grid and to all ratepayers. For the storage system to provide these benefits, the DC photovoltaic system must be sufficiently oversized compared to the inverter limit because the storage system needs to be able to charge during daylight hours with energy that isn't being exported to the grid in real time.

The Joint Solar Parties note that the question of a peak load reduction program for solar+storage for both behind-the-meter systems and front-of-meter systems is currently being litigated in both utilities' multi-year grid plans.

2. What other Program requirements should be amended to support systems with storage components? Please provide details on the requirement that should change, how it should change, and why it should be different for systems with storage components.

JSP RESPONSE: Generally speaking, the Joint Solar Parties believe that the current Part I and Part II application requirements—especially subject to modifications proposed by the Joint Solar Parties elsewhere—are sufficient to support solar+storage. The primary inhibition is the maximum DC/AC ratio.

TOPIC 8: IEEE Inverter Requirement

Questions

1. As the Agency plans to modify its requirements to align with the ICC's Order, do stakeholders foresee any unintended consequences of such updates? Please provide any feedback on positive or negative consequences that may result.

JSP RESPONSE: As an initial matter, the Joint Solar Parties are unsure the basis for additional requirements on inverters beyond what is required for successful interconnection, especially for systems that are currently or not currently taking the smart inverter rebate.

After January 1, 2025—subject to statutory safe harbors and additional terms and conditions to be addressed in the investigation pursuant to Section 16-107.6(e)—the Joint Solar Parties agree that new systems are nearly all likely to take advantage of the Smart Inverter Rebate. However, the (substantial) subset of Small DG systems on residences that can continue to qualify for full retail net metering will not necessarily take advantage of the Smart Inverter Rebate and thus need not meet the minimum requirements in that tariff. The Joint Solar Parties believe it is reasonable to assume that projects in other categories will take advantage of the Smart Inverter Rebate, but it is not an accurate assumption for residential systems at least through the 2024-25 program year.

2. Should requirements related to inverters be broadened or narrowed? Explain how so.

JSP RESPONSE: Subject to the limitation above, the Joint Solar Parties do not object to the requirement that inverters meet minimum tariff-based requirements for the Smart Inverter Rebate. However, the Joint Solar Parties are concerned that adding one more issue to review for the Program Administrator will only serve to slow the process down when inverters are a key component of the interconnection process and (subject to the limitation above) the Smart Inverter Rebate is an important revenue stream. Thus, other than perhaps harmonizing with the Smart Inverter Rebate for all but residential systems (at least through the end of the 2024-25 program year), the Joint Solar Parties oppose any additional requirements.

TOPIC 10: Proposal to Require the IPA's Equity Portal to Certify Equity Eligible Persons (EEPs) for Compliance with the Minimum Equity Standard (MES)

Questions

1. Are there any unintended consequences that may result from requiring EEPs to use the Equity Portal for certification of their EEP status?

JSP RESPONSE: The Joint Solar Parties do not generally object to this requirement, provided that the Equity Portal remains stable and regularly online and the IPA acknowledges that requiring the use of the Energy Workforce Equity Portal does not resolve all concerns with verification of EEP status. In addition, the Joint Solar Parties urge the IPA in the strongest terms to ensure confidentiality of all information submitted as proof of qualification and ensure that EEPs who register for compliance purposes are in an entirely separate database from those who register to connect with employers. If there is cross-over between the two, Approved Vendors and Designees are likely to see recruiters and competitors come after their EEP employees and contractors on a massive scale and thus create compliance instability. The Joint Solar Parties note the challenge of Approved Vendors that on one hand (rightfully) do not want to provide PII, confidential information, or personally sensitive information of their employees, independent contractors, or vendors' employees and independent contractors to the Program Administrator but on the other may have limits on the ability to compel a reluctant employee from using the Energy Workforce Equity Portal.

2. Do stakeholders see any issue with shifting the reporting work onto the EEPs themselves as opposed to the participating AV or Designee?

JSP RESPONSE: While the Joint Solar Parties understand and appreciate the burden on individual people and sensitivity around requiring EEPs to self-register, such an approach prevents the risk-laden scenario where a contractor (or subcontractor) collects proof of EEP status from the EEP—which may be PII, confidential, personally sensitive, or some combination thereof—and provides it to the Approved Vendor or Designee for provision to the Program Administrator. Similar to the marketing guidelines, the Joint Solar Parties assume that the IPA prefers to minimize the touch of Approved Vendors or Designees of PII, confidential, or personally sensitive information from EEPs. While the Joint Solar Parties

believe that the industry generally would make all efforts to protect such information, not all Approved Vendors, Designees, or contractors/subcontractors are equipped to handle PII, confidential, or sensitive personal information from contractors for regular submission to a government entity.

The Joint Solar Parties also note that for some immigrant communities in particular, there is sensitivity around releasing address information to the government or its agents. While the Joint Solar Parties appreciate the importance of verification, the Joint Solar Parties wish to emphasize the importance of confidentiality and concern about governmental disclosure. To that end, the Joint Solar Parties urge that data be kept in an encrypted state and identifying documents kept in a separate database—verification of EEP status should only be available to those checking and not involved in review of eligibility should only be displayed as "yes" or "no". The Joint Solar Parties stand ready to work with the IPA and the Program Administrator on confidentiality concerns.

For Approved Vendors that prefer to shield their employees or contractors – for whatever reason – from shouldering the reporting burden, Joint Solar Parties strongly urge the IPA to allow Approved Vendors to sign an auditable affidavit that states that their MES status listed in the end-of-the-year report is accurate and complete to the best of their knowledge, as of the submittal date. Affidavits are a standard method of ensuring compliance that keep the burden of compliance on the subject company, rather than individuals. Joint Solar Parties sees no reason why in this case, an auditable affidavit is not an appropriate compliance tool, when it is used for so many other purposes. The Joint Solar Parties stand ready to work with the IPA on any legislative changes that may be necessary to implement this approach.

3. What is the preferred method for the certification of EEPs for compliance with the Minimum Equity Standard?

JSP RESPONSE: Certification through the portal or by mail. While it is reasonable to assume that Approved Vendors and Designees have ready access to the internet and to scanners or similar devices, the Joint Solar Parties are not in a position to make the same assumptions about all EEPs at all times. In addition, to remove the potential for a company that is not an Approved Vendor or Designee to provide PII, confidential information, or personally sensitive information to an Approved Vendor or Designee for submission as proof of EEC status, for situations where the Approved Vendor or Designee (depending on who is reporting) does not have a direct employment, co-employment, or independent contractor relationship then the IPA should consider alternative forms of proof that do not involve multiple parties handling PII, confidential, or personally sensitive information of the EEP.

4. Are there potential barriers to access the Equity Portal for qualifying individuals that the Agency should consider?

JSP RESPONSE: Yes, internet and scanner access (the latter for taking paper proof and digitizing it). Please see above as well.

TOPIC 11: Application Requirements

Questions

1. Are there any application requirements that require updating? If so, please explain which requirements and how they should be updated.

JSP RESPONSE: The Joint Solar Parties make several recommendations, including:

- **Panel and inverter models should not be required in the Standard Disclosure Form or Part I application. Frequently until EPC begins the developer does not know what make and model they will use, which instead depends on price and availability at the time.**
- **Part II applications should not require photographs of the entirety of the solar array or all of the modules or inverters. It is unclear what this requirement accomplishes.**
- **The Part II application should include an upload for the Certificate of Completion and not separate entries for the date placed in service or interconnection date. If none is available (but the system is in fact interconnected), that should be an alternative entry rather than an independent requirement.**

2. Are there any application requirements that should be tightened?

3. Are there any items that are not currently application requirements but should be considered for addition to the requirements list?

JSP RESPOSNE: The Joint Solar Parties do not support additional requirements (such as minimum inverter specifications or certifications) at this time.

4. Are there any application requirements that no longer apply or make sense that should be reconsidered?

JSP RESPONSE: Please see the Joint Solar Parties' response to Question 1 within this Topic 11 above.

Responding further, the Joint Solar Parties note that collecting demographic data per project for Small DG category is inefficient and does not provide the full picture of the diversity within Approved Vendor's workforce and employees - for example it does not contemplate the employees' time on projects that never make it across the finish line to be submitted to ABP, nor does it account for warehouse employees, permit workers or O&M employees on service calls to existing fleets. The Joint Solar Parties encourage annual portfolio reporting of demographic data instead of project by project for Small DG category, and recommend the IPA consider this approach for other sectors as well.

TOPIC 12: Barriers to Participation in the EEC Category & Program-wide for EECs

Questions

1. What are current barriers that Program participants face in their participation in either the EEC category or the Program in general that should be understood by the Agency? Please provide a detailed explanation of the barrier and suggestions on how the Agency might work to overcome the barrier.

JSP RESPONSE: The Joint Solar Parties continue to recommend that EECs have expanded cure rights for defaults and failures to meet Part I and Part II requirements not otherwise available to an Approved Vendor. In addition, projects initially applied by an EEC should have far expanded rights to cure issues with development during the term of the REC Contract if the changes are made by an EEC. These two aspects will greatly reduce the reps and warranties required by a long-term owner/operator purchasing an EEC-developed system (even if the EEC remains the Approved Vendor) or the long-term owner/operator's financing parties. This ability is a market differentiator for EECs that are breaking into development—and thus may not be perfect on their first several tries—and a way for EECs to avoid taking either a steep price reduction or intolerable risks in reps and warranties as a result of that inexperience.

2. Are there future barriers that entities expect to face in this category as it ages that are not currently present of which the Agency should be aware?

JSP RESPONSE: While certainly not all EECs are new market entrants, that group of new market entrants that the statutory category of EEC is trying to attract needs protection from risk. The essence of development is that it can go wrong in many different ways, leading to additional costs and losses (including total losses). The more streamlined the EEC Block can be or EEC participation in other aspects, the more ABP "program" risk can be taken off the table. Even personnel at well-established developers (whether inexperienced or not) make costly mistakes or oversights—the difference is a well-established developer is more likely to have the experience, resources, and knowledge to fix the problem while new market entrants are likely to have less of all three. The IPA should make efforts to ensure that it does not continue to add complication to the EEC Block as it has in other categories—at least if it wants successful participation by new market entrants.

Similarly, the program rules should encourage the growth of EECs that specialize in specific pieces of the project development process (including pre-Part I Application site specific development work, construction specialty work such as electrical contractor, and long-term system owner/operator activities). There is significant value to market participants in being able to specialize, and alternatively, significant risk and barriers to entry involved in assuming or requiring that EECs/all market participants control every piece of the development or even EPC process.

TOPIC 13: Traditional Community Solar Scoring Guidelines

Questions

1. Should the Agency consider another approach to discourage the development of TCS projects on greenfields or land that is available for conservation? Please provide details on what approach the Agency might use to ensure development does not coincide with this type of land.

JSP RESPONSE: As an initial matter, the Joint Solar Parties disagree that greenfield projects are less meritorious or should be disincentivized. To successfully achieve an economically efficient clean energy transition for the State of Illinois, all project types, greenfield or otherwise, should be encouraged. While the Joint Solar Parties agree that land under active conservation should not be developed, limiting solar development on farmland and other rural land that may be "available" for conservation takes away a viable revenue option for private property owners and creates development barriers for the renewable industry. In the experience of the member companies to the trade associations that comprise the Joint Solar Parties, some rural landowners prefer to lease land to solar development compared to more intensive development options precisely because the land can one day be easily converted back to farming or conservation. Eliminating solar as an option for landowners may have the unintended consequence of pushing landowners towards more intensive land uses that are not compatible with pollinator habitat or future agriculture or conservation opportunities. Rather than discourage development of TCS projects on greenfields, the Agency may want to consider encouraging responsible stewardship of land throughout the project life or life of the REC contract.

The Joint Solar Parties also note that the legislative intent of SB2226 was to dissuade use of unrelated conservation provisions of statute from interfering with the state's renewable energy goals. Finding a clever end-around or alternative barrier to development in COAs or similar designations would frustrate the General Assembly's clear intent.

While many developers focus on rural development, the Joint Solar Parties note that other developers focus on rooftops or urban/suburban development or on contaminated land. The Joint Solar Parties note that non-greenfield projects generally carry higher development costs and/or risks, and that ground-mounted TCS projects in more densely populated urban/suburban communities are not always welcome by neighbors. Biasing TCS development away from greenfield locations sparsely populated parts of the state may inadvertently set-up more frequent land-use conflicts with urban or suburban communities.

2. Are there any changes that stakeholders can suggest that may reduce the administrative lift of scoring TCS projects, while still accomplishing the goal of differentiation between projects?

JSP RESPONSE: Less complicated scoring criteria to allow quicker scoring review and less intensive back and forth between AVs and the Program Administrator and elimination of mid-review rule changes such as the contaminated land/brownfield reinterpretation or the township-level benefits requirement introduced *after* CDCS scoring. The Joint Solar Parties note that implementation of those criteria frequently required Approved Vendors to provide

substantial additional narratives, some of which were supported by environmental consultant reports, creating substantially more complication and documentation to review.

Responding further, if the administrative lift of scoring TCS projects is too high, perhaps despite best intentions it is not feasible to address all of the criteria originally assessed. Without more information about which requirements the Program Administrator found to be burdensome or why—or why the Program Administrator struggled with consistency or evaluation in certain areas, requiring multiple audits—it is not possible to suggest targeted fixes.

The Joint Solar Parties note their longstanding opposition to scoring or points systems. The delays in scoring of TCS provide a demonstration of some—though not all—of those concerns with scoring systems, particularly subjective scoring.

3. Does the interconnection fractional point process provide enough differentiation between projects? Should this process be revamped at all? If so, please explain why.

JSP RESPONSE: The fractional point is essentially a tiebreaker based on a maturity criteria (date of interconnection agreement), which the Joint Solar Parties have consistently supported. The Joint Solar Parties would support additional emphasis on the date of a project's interconnection agreement to further differentiate between projects.

4. Do stakeholders find that commitments to scoring points both under Agrivoltaics (scoring criterion 1.c) and the Pollinator Friendly Habitat (scoring criterion 1.d) are at odds? If so, please explain why and how the Agency can amend these scoring criteria to solve for this issue.

JSP RESPONSE: Not in theory, but in practice with the IPA's particular implementation due to the pollinator scorecard. Essentially, because the pollinator scorecard requires commitments to pesticide-free sites, the crops available for agrivoltaics are severely limited. The IPA should work with industry and the farming community to ensure that the pollinator scorecard requirements do not undermine typical, common, or desirable agricultural uses.

5. Please provide any other feedback on changes to the TCS scoring guidelines that might be relevant to ensuring that the multiple goals of TCS project development – encouraging solar development state-wide, best utilizing land in the state that cannot be otherwise utilized for conversation/farming/etc., and diversifying project attributes amongst TCS projects.

JSP RESPONSE: The Joint Solar Parties disagree that placing solar on farmland is inconsistent with statutory goals or harmful to farming. If anything, the IPA should be incentivizing the conversion of farmland to agrivoltaics (inclusive of pollinators) because it provides multiple environmental benefits to the preexisting farmland and when executed properly minimal impact on the farmland itself.[1] Sophisticated approaches to agrivoltaics

[1] There is growing body of scientific literature available about the benefits of integrating pollinator habitat with solar farms, including research conducted by researchers at Argonne National Lab. Some sample publications:

- "Modeling the ecosystem services of native vegetation management practices at solar energy facilities in the Midwestern United States" Leroy J. Walston, Yudi Li, Heidi M. Hartmann, Jordan Macknick, Aaron Hanson,

now ensure not only less intrusion on farmland but also symbiosis (such as supporting plants that grow better without direct sun). In addition, the Joint Solar Parties continue to not understand what "diversifying project attributes amongst TCS projects" means or why it benefits the statutory goal of 45,000,000 RECs procured from new wind and new solar photovoltaic systems in Section 1-75(c)(1)(C) of the IPA Act.

Responding further, the Joint Solar Parties propose the following changes:

- **EEC should be revised to reflect EEC capabilities and provide more granular involvement of EECs performing specific scopes. For instance, having an EEC as an electrical contractor is an important scope, but itself is nowhere near 50% of REC Contract value. Use of multiple subcontractors within the engineering and construction components of EPC (and construction-adjacent functions such as environmental reviews, site evaluations such as drain tile surveys or testing such as push-pull) should be identified and rewarded beyond dollar spend. While total dollar spend has a role—such as the MWBE spending commitment under Solar for All that does not require use of MWBE subcontractors as long as the contractor is MWBE—use of specialized EECs has a different but substantial value. Respectfully, the Joint Solar Parties recommend that the IPA consider ways to allocate points for use of multiple EEC subcontractors or vendors rather than only providing opportunities for EEC prime contractors.**

- **The current structure of scoring criteria 2.c has helped contribute to geographic diversification of projects, however it is highly likely that zero counties will remain eligible for points in Group B following scoring of projects for capacity in the 2023-2024 program year. Moving forward, it will be important for the IPA to provide additional drivers for geographic diversification, including drivers that are persistent beyond a single program cycle. One such option is providing 2 points for *first in municipality* (i.e. the first community solar project to be permitted through any specific municipality). These projects serve the IPAs goals of greater geographic diversification, while also incentivizing projects sited closer to load centers, with greater community engagement and discretion in permitting approval, as well as**

Chris Nootenboom, Eric Lonsdorf, Jessica Hellmann: https://www.sciencedirect.com/science/article/pii/S2212041620301698

- "Examining the Potential for Agricultural Benefits from Pollinator Habitat at Solar Facilities in the United States," Leroy J. Walston, Shruti K. Mishra, Heidi M. Hartmann, Ihor Hlohowskyj, James McCall, and Jordan Macknick: https://pubs.acs.org/doi/10.1021/acs.est.8b00020
- "Environmental Co-Benefits of Maintaining Native Vegitation with Solar Photovoltaic Infrastructure," Chong Seok Choie, Jordan Macknick, Yudi Li, Dellena Bloom, James McCall, and Sujith Ravi (https://agupubs.onlinelibrary.wiley.com/doi/10.1029/2023EF003542)
- "Agrivoltaics Provide Mutual Benefits Across the Food-Energy-Water Nexus in Drylands," Greg Barron-Gafford, Mitchell Pavao-Zuckerman, Rebecca Minor, Leland Sutter, Isaiah Barnett-Moreno, Daniel Blackett, Moses Thompson, Kirk Dimond, Andrea Gerlak, Gary Nabhan, and Jordan Macknick (https://www.researchgate.net/publication/335583033_Agrivoltaics_provide_mutual_benefits_across_the_food-energy-water_nexus_in_drylands)
- "Harvesting the Sun: On-Farm Opportunities and Challenges for Solar Development," Anuj Krishnamurthy and Oscar Serpell (https://protect-us.mimecast.com/s/nBi7Co269xfroM2JT2fEpc?domain=kleinmanenergy.upenn.edu).

greater tax revenue for local communities. Based on what data the IPA already tracks in the Part I and Part II applications, such points should be easily trackable and therefore less labor intensive in terms of application review. Such a scoring mechanism provides continued incentive for geographic diversification as points for "first in county/township" quickly dry up.

- **Interconnection queue position / project readiness - As the Joint Solar Parties have noted in previous regulatory filings, the "Top 2 on substation queue" standard (points criteria 4.b) is flawed as it relates to project readiness in that it applies a somewhat arbitrary and unnecessarily high burden that precludes a large number of projects from receiving points that can easily demonstrate a simple interconnection path. The Joint Solar Parties recommend expanding eligibility to these points to projects that can demonstrate interconnection costs (inclusive of contingent upgrades) of less than $0.30/Wac (the current threshold in the REC Contract for partial return of collateral), generally regarded in the current environment as a reasonable interconnection cost in Illinois (especially in the ComEd service territory). The value of upgrade costs, as well as the projected cost of any contingent upgrades, is clearly listed in the interconnection agreements already being provided to the IPA at application submission. The vast majority of 2-5MWac community solar projects (most community solar projects) can afford upgrades less than $0.30/Wac, making this a better assessment of project readiness than substation queue position. The fact that the IPA can quickly and easily make this determination based on documentation already provided makes this an attractive points criteria option from an administrative lift perspective. The JSP therefore recommends adding "aggregate interconnection costs under $0.30/Wac" to the 4.b points, also eligible for 2 points. The Joint Solar Parties further recommend adding a tier for a single point for interconnection above $0.30/Wac and below $0.60/Wac.**