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Comments on Behalf of the Coalition for Community Solar Access Regarding the Long-Term Renewable Resources Procurement Plan

I. Introduction

The Coalition for Community Solar Access (CCSA) appreciates the efforts of the Illinois Power Agency (IPA) as it works to design new programs to spur renewable energy, pursuant to Public Act 99-0906, the Future Energy Jobs Act. We welcome the opportunity to help the IPA meet the requirements of the Act and design programs that create a diverse, competitive and consumer-friendly community solar market.

CCSA is a business-led trade organization, comprised of 32 member companies, that works to expand access to clean, local, affordable energy nationwide through community solar. Our mission is to empower energy consumers, including renters, homeowners, businesses and households of all socio-economic levels, by increasing their access to reliable clean energy. CCSA, in partnership with a thriving network of non-profits, affiliate trade associations, and allied stakeholders, serves as the central voice for the community solar industry in developing vibrant and sustainable markets for community solar. CCSA members are active nationwide and we have been actively engaged in the informal Illinois stakeholder process to date. The feedback provided in these comments is based largely on our members' extensive experience working in other states and participating in a diverse array of policymaking efforts. This experience has provided us with a clear understanding of which policies work to balance the needs of all players and create a healthy community solar market and; conversely, which ones hinder market participation, ultimately limiting options for consumers.

II. Adjustable Block Program

a. Blocks

1. What approaches should the IPA consider for determining the size of blocks? What are the advantages/disadvantages of having a larger block size as opposed to a smaller block size?
and
2. Should the category for systems between 10 kW and 2 MW be subdivided into distinct blocks? And if so, what are the appropriate break-points (e.g., 100 kW, 200 kW, 500 kW) between categories, and why?

There are a number of overarching considerations that may be important for the IPA to consider when designing the Adjustable Block Program (ABP), most notably: simplicity, transparency, and predictability. There are a number of ways that these considerations can manifest in program design. Based on our experience working in other states CCSA offers the following recommendations for the design of the ABP blocks.

1. Block design should account for realistic project development timelines

The ABP blocks must be large enough to provide needed certainty for project development: CCSA recommends no more than three or four blocks for community solar in each utility territory, along the lines suggested by SEIA. For example, we think that this could be divided up such that 40% of the MW allocation for community solar be attributed to Block 1, followed by two additional blocks of 30%. Community solar development typically takes longer than comparably sized projects given these projects' unique customer acquisition, as well as longer permitting and interconnection timelines associated with ground-mounted solar projects. As a result, development timelines for community solar projects regularly reach 18 months or more. The blocks under the ABP must be large enough that a developer can have a reasonable idea of which block a project is likely to fall into before making major investments to advance the project. We also provide a suggestion later in these comments regarding the fourth unallocated tranche of ABP allocation.

2. Avoid block segmentation

CCSA does not support dividing up program capacity by project size. The ABP will likely already be segmented by utility service territory and by project type (under 10 kW, over 10 kW, and community solar). Any further subdivision will decrease the size of each individual block and decrease the amount of capacity available to any given project type. Under a fragmented block structure, community solar developers could be forced to make major investment decisions without knowing into which of several different blocks the project would fall. This uncertainty could make a significant difference in the financial viability of projects and would greatly increase the risk of stranded project investments that would make development of community solar projects more difficult and costly. In addition, since the precise level of customer demand for different project types is not yet known, dividing up the program at the outset is likely to lead to shortages of capacity in some areas and surpluses in others. Rather than dividing up the program, providing adders to smaller projects would be a more efficient way to support development of projects of different sizes.

3. Provide a gradual, transparent and predictable block transition process.

To further mitigate risk in the project development process, the transition between blocks should be gradual and predictable. Steep transitions between blocks could increase the risk of stranded project investments if projects receive a significantly less renewable energy credit (REC) value than they were expecting. A gradual transition would provide a strong financial incentive for projects to be completed in a timely manner without imposing undue risk on solar developers and customers. For a good example of a gradual transition, the new Solar Massachusetts Renewable Target (SMART) Program will step down 4% between blocks.[1]

CCSA also recommends that the program administrator or utilities maintain a public online dashboard that shows in real time (or as close to real time as possible) the amount of each block that has been reserved. Good examples of these dashboards include the Massachusetts System

[1] See 225 CMR 20.00: Solar Massachusetts Renewable Target (SMART) Program Emergency Regulations, Sec. 20.07, available at http://www.mass.gov/eea/docs/doer/rps-aps/225-cmr-20-00-draft.pdf.

of Assurance of Net Metering Eligibility, maintained by a consultant on behalf of the Massachusetts investor-owned utilities and Department of Public Utilities,[2] and the NY-Sun incentive dashboards maintained by the New York State Energy Research and Development Authority.[3]

3. Should the initial block or blocks have a different structure than subsequent blocks to account for expected pent up demand?

In addition to pent-up demand for community solar capacity, developers will likely incur higher costs at the opening of the market. Companies must adapt or create marketing information and business models and contracts for a new market, in addition to devoting significant resources to consumer education. Allowing for a larger MW allocation or longer time period for the first block would help developers invest the resources needed to jumpstart the market in Illinois.

4. What criteria should be used to prioritize projects within a block when applications exceed the remaining available capacity in a block? Should the projects be prioritized on a first-come first–served basis or by other criteria?

CCSA strongly recommends using a first-come, first-served approach for allocating block capacity. Our members' experience in other states has shown this to be the most transparent and fair method. Prioritization based on other factors would require some subjective review criteria, causing administrative delays and creating openings for disputes. In a MW block structure, when more projects apply to a block than capacity allows, those projects should be moved into next block based on the date and time the application was received.

b. Prices

6. Should the ABP REC prices be based on a cost-based model, which takes into account the revenue requirements for new projects in Illinois, or should it be based on market observations of pricing data as well as developments in other jurisdictions?

> *a. For the cost-based approach please provide recommendations for data inputs that should considered for the model. If there are publicly available models that could be used as a template, please provide information about those models.*

CCSA recommends ABP REC prices be based on a cost-based model. Basing them on market observations from other states would not take into account the major differences in costs and revenue structures across markets and greatly runs the risk of over- or under-stimulating the market. However, the IPA can and should rely on policy-design approaches from other states to understand the factors that should be considered when setting REC prices. In particular,

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[2] Available at http://www.massaca.org/. In addition to tracking overall allocation of net metering capacity, the System of Assurance provides publicly available, downloadable data showing the reservation status of each individual project. This project-level disclosure provides maximum transparency and accountability for market participants.

[3] Available at https://www.nyserda.ny.gov/All-Programs/Programs/NY-Sun/Megawatt-Block-Dashboards.

Massachusetts has spent a considerable amount of time and resources to understand the costs and drivers of the entire solar market to try and set incentive levels to meet a policy goal of 1600 MW of distributed solar.

In 2016, the Massachusetts Department of Energy Resources (DOER) hired consultants to inform the development of a successor incentive program to follow the Commonwealth's Solar Carve-Out II (SREC II) program. Although the successor incentive program has not yet been finalized, the consultant's report may be useful to consider as it provides a comprehensive framework for understanding the important variables to consider when setting REC pricing.[4]

It is important to note that the DOER consultants omitted some important cost categories for community solar, which should be considered in Illinois' approach. When accounting for project costs, the Massachusetts' Consultant Report does not appear to account for the initial community-solar-specific customer acquisition costs (marketing and sales), or the costs associated with managing onboarding of the customer, specifically contract verification and sizing of the subscription. The Consultant Report also may have underestimated O&M costs for community solar, which are higher than non-CSS projects of comparative size, given the costs associated with ongoing communications, servicing, accounting and crediting an entire community of customers – not just a single customer – as well as replacing project subscribers, and accounting. The Consultant Report acknowledges this, but is not clear which costs were used. These customer-related costs are the largest driver of cost differences between community solar and similar, non-community solar projects, so capturing them accurately is essential. In Massachusetts, DOER has subsequently accounted for these costs by creating a community solar adder within the new incentive program.

8. Besides geography and system size, are there other factors that should be considered to create differentiated pricing?

As noted in our response to the above question, community solar development incurs some unique costs that do not apply to comparably sized non-community-solar projects. Educating, signing up, and retaining community solar customers requires substantial effort, as a MW-scale project may serve hundreds of customers. Billing and customer service functions must also be established, operated and maintained. On a per-watt basis, these costs can more closely resemble residential rooftop development costs than typical offsite ground-mount systems.

The IPA should also maintain a forward-thinking approach regarding the interplay between multiple incentives and revenue streams. As Public Act 99-0906 mandates that the $250/kW DG rebate will be replaced by a location-based incentive when net metering penetration hits 5%, the IPA should design an ABP that can be adjusted to accommodate for significant changes in the market. In essence, developers need long-term predictability and gradual transitions. A steep drop-off in incentives would likely disrupt the market and forestall future development. Given the uncertainty of what that next incentive might look like, the Program Administrator may want to have the flexibility to adjust the ABP to avoid a possible disruption in the market.

[4] See Historical Development of the Solar Carve-Out II, at http://www.mass.gov/eea/docs/doer/rps-aps/developing-a-post-1600-mw-solar-incentive-program.pdf.

The ABP may also need to be adjusted to account for changes at the federal level that affect the economics of solar in Illinois, including step-downs in the federal Investment Tax Credit and the potential impact of the current trade case affecting solar panels.[5]

c. Project development process

For the questions in this section, CCSA generally points to the processes used in Massachusetts to allocate net metering capacity and incentives. Massachusetts sets a relatively high bar to demonstrate project maturity in order to reserve net metering or incentive capacity, with strict but reasonable deadlines for completing a project once capacity has been allocated.

To manage the allocation of net metering capacity, the Massachusetts Department of Public Utilities relies on a third-party administrator, which maintains the System of Assurance, an electronic reservation system. There appears to be broad industry consensus that the System of Assurance process is clear, straightforward and efficient. More information can be found in the Department of Public Utilities' order for creating the System of Assurance[6] and the User Help and Guidance website that both provide detailed information about the process.[7]

Briefly, the System of Assurance is comprised of the following steps:

1. Applicants for a net metering cap allocation register for an online account and submit a reservation for capacity, supplying the following:
    a. General facility information
    b. Executed Interconnection Services Agreement
    c. Documentation of site control (executed lease agreement or signed option)
    d. All necessary, executed governmental non-ministerial permits and approvals
    e. A $100 application fee
2. After the Administrator reviews and determines a submitted application is complete, an applicant has 15 business days to submit a reservation fee of $3.15 per kW_{AC} to reserve a Cap Allocation.[8]
3. The applicant has 9 months to complete the project and may extend the reservation period for 6 months for an additional deposit. The reservation can also be extended if a governmental approval for the project is subject to a legal challenge or if the project is mechanically complete and awaiting authorization to interconnect.
4. Applicants must report all major changes to the Program Administrator or report on the facility's status at least quarterly until the project receives authorization to interconnect, using a simple online reporting form.[9]

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[5] See, e.g. Greentech Media's article, *It's Official: The Government Is Moving Forward With Suniva's Solar Trade Case* available at https://www.greentechmedia.com/articles/read/the-government-is-moving-forward-with-suniva-solar-trade-case.
[6] See DPU Order 11-11-A Appendix A: SYSTEM OF ASSURANCE OF NET METERING ELIGIBILITY, at http://www.massaca.org/pdf/DPU%20Order%20App%20A_102512.pdf.
[7] User Help and Guidance at http://www.massaca.org/help.asp.
[8] See MassACA.org Reservation Period Requirements, at http://www.massaca.org/pdf/ReservationPeriod.pdf
[9] See MassACA.org Quarterly Reports, at http://www.massaca.org/pdf/QuarterlyReports.pdf

Reservations under the Solar Carve-Out II (SREC II) program are managed by the Massachusetts Department of Energy Resources. Projects must provide the same three sets of documentation to demonstrate project maturity: site control, an executed interconnection agreement, and all non-ministerial permits (i.e., permits that require a discretionary review such as a peer review or vote. These do not include typical building and construction permits.). Reservation and extension rules for SREC II are also similar to those for net metering reservations.

9. How much time should be allowed between system application/contract approval and when a system must be energized? The time allowed could take into account issues like (i) the seasonality of applications, (ii) delays in permitting, interconnection, (iii) equipment availability and etc. Should this time vary by size of system, geographic location, or interconnecting utility?

Project completion deadlines will ensure that feasible projects move forward at a reasonable pace without tying up valuable space in the ABP program. Maryland's Community Solar Energy Generating System Program,[10] and the Massachusetts Solar Massachusetts Renewable Target[11] will provide a 12-month window to bring systems online. Xcel Energy's Community Solar Gardens program in Colorado provides 18 months for project completion.[12] For another point of reference, Minnesota's Community Solar Gardens program allows 24 months for project completion but allows fewer options for project extensions and that timeline is starting from an earlier phase in project development.[13] Based on these examples and our experience with project development in other states, CCSA recommends allowing a timeline of at least 12-18 months from application approval to when a system is energized, which will help to spur development along at an efficient pace. As note in question 11 below, strong requirements for entry into the incentive queue should minimize the project development time needed after acceptance into the program. In addition, the Program Administrator should also allow for extensions to this deadline when appropriate (as discussed in the next question). During this time, we recommend that project developers submit regular reports to update the Program Administrator of the status of project development.

We recommend applying this window to all community solar projects, regardless of size. Other types of projects may require different completion timelines.

10. What type of extensions to a guaranteed in-service date should be allowed, and what additional requirements should there be for extensions?

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[10] See COMAR 20.62.03.04 (C), available at http://www.dsd.state.md.us/comar/comarhtml/20/20.62.03.04.htm.

[11] Note that this program is still in development. See the MA SMART Emergency Regulations, Sec. 20.07, available at http://www.mass.gov/eea/docs/doer/rps-aps/225-cmr-20-00-draft.pdf.

[12] See Xcel Colorado's FAQ's for Subscriber Organizations, available at https://www.xcelenergy.com/staticfiles/xe/Marketing/Managed%20Documents/co-sr-communities-faqs.pdf.

[13] See Xcel Standard Contract for Solar*Rewards Community, available at https://www.xcelenergy.com/staticfiles/xe/Marketing/Files/MN-SRC-Standard-Contract.pdf.

CCSA recommends that no-fee extensions should be allowed at least for projects that face legal challenges as well as those that are pending authorization to interconnect. Additionally we recommend that projects in need of an extension for other reasons should be allowed to pay a fee for an extension. This approach has been adopted in a number of states including Massachusetts and Maryland. For example, Massachusetts provides for the following extensions to net metering capacity reservations:[14]

- Extended Reservation Period for a Fee

  > A Host Customer with a Cap Allocation may seek an additional extended Reservation Period for six months provided that such Host Customer has submitted a fee of $3.15 per kW. The fee shall be held in escrow by the Administrator and refunded to the Host Customer without interest, provided that the Facility receives notice of authorization to interconnect within six months (or receives an extension pending authorization to interconnect, described below).

- Extended Reservation Period for Legal Challenges

  > Any Host Customer may seek an extended Reservation Period of six months if the Host Customer submits a Certification that a governmental permit or approval for the Facility was subject to a legal challenge during the initial Reservation Period or extended Reservation Period, and the legal challenge remains pending. However, the extended Reservation Period for legal challenges terminates at the end of the legal challenge. Any and all other Reservation Period timelines are suspended during the extended Reservation Period for legal challenges. There is no fee for an extension under this provision.

- Extended Reservation Period Pending Authorization to Interconnect

  > When a Facility's interconnection depends only upon receipt of notice of authorization to interconnect, the Reservation Period shall be extended until such notice is received or denied. Any fees associated with [the Extended Reservation for a Fee] shall not be forfeited solely as a result of seeking this extended Reservation Period pending authorization to interconnect.

CCSA recommends the IPA take a similar approach as Massachusetts because it provides motivation to meet project completion deadlines while, at the same time, allowing extensions for reasonable justifications.

11. What information about a system should be required for a system to be qualified to participate in the program (e.g. site control, local permitting, interconnection status, etc.)? Should the requirements be different for smaller systems (e.g., under 10 kW) than larger systems? Should the requirements be different depending on whether the system is being interconnected with an investor-owned utility, a municipal utility, or a rural electric co-op?

[14] See DPU Order 11-11-A Appendix A.

Again, CCSA recommends using the Massachusetts process as a template. The application process requires the following information:

- General project information (Address, owner, contact information, utility account, etc);
- An Executed Interconnection Services Agreement, signed by the applicant and utility;
- Executed Documentation of Site Control including an executed lease agreement or signed option; and
- All necessary, executed governmental non-ministerial permits and approvals required to construct the facility (those that include some level of discretion).

These requirements will ensure that only mature projects are accepted into the ABP and reduce the chance that speculative projects waste valuable time and space in the program queue. Additionally, these upfront requirements will allow projects to move forward more quickly in the construction phase. These requirements should generally be consistent across system types, sizes and utilities.

In addition, CCSA recommends the IPA create a clear process for determining a waitlist for each type of block in the ABP, as well as a clear process for developers to determine where their projects are in line.

12. What development deposit/credit requirements should there be in addition to any program fees? And for how long should such requirements run?

CCSA recommends requiring a reservation fee for ABP capacity in addition to a reasonable application fee for processing the ABP application. This reservation fee should be low enough to not be a significant financial hurdle but set at a level to discourage speculative projects from reserving space in the program.

Beyond the reservation fee, CCSA does not support the inclusion of a performance bond, surety or other security requirement as part of the application process. Onerous credit requirements or other program features serve to limit participation in the market and drive up prices for subscribers. Bonds and other security requirements may be cost-prohibitive to all but the most sophisticated and well-established providers, which can ultimately reduce competition in the marketplace leading to higher prices, less innovation and less opportunity for customer participation.

13. Should there be intermediate project milestones to help ensure that projects that have reserved RECs out of a block are successfully developed, and that closure of blocks due to all RECs being allocated is effectively managed? If so, how should milestones and performance standards vary between smaller and larger projects?

CCSA recommends against setting intermediate project milestones because project development does not always happen on the same timeline for all projects. Further, this would add administrative burdens on the Program Administrator. Instead, CCSA recommends that developers provide the Program Administrator with project development updates on a regular basis (at least quarterly) and when any project information has changed. The update submittal process should be easy and straightforward.

d. Clawback Provisions

Questions 15 - 18

To qualify for participation in the ABP, it is appropriate to require community solar facilities to meet the basic definition of community solar throughout the 15-year life of the renewable energy credits, checked annually by the Program Administrator. This could be accomplished by requiring the project owner to submit an annual report either re-affirming that their original information is current or, if it has changed, providing updated information. If a subscriber with a substantial offtake drops out of the project it may take time to replace that subscription. We recommend allowing a reasonable amount of time, i.e. six months, for a project to regain compliance with the requirements of a community solar facility.

CCSA further recommends waiving the clawback provisions if generation is reduced, stalled or stopped due to events that are outside the control of the project owner or developer, such as weather events (i.e. tornado) and utility curtailment.

e. Consumer Protection

19. What consumer protection elements should the IPA consider adopting as part of the ABP program? How should those elements differ between distributed generation and Community Solar?

CCSA member companies have a vested interest in consumer protection. As a condition of membership, each CCSA member company has agreed to adhere to a set of nine Core Principles for developing effective community solar policies and programs.[15] Of those nine Core Principles, three focus on consumer protection:

- Provide assurance of on-going program operations and maintenance to ensure overall quality, that the facility lasts for decades, and that customer participation is protected. Safeguard the continuity of program benefits to protect customers and developers' investment.
- Ensure full and accurate disclosure of customer benefits and risks in a standard, comparable manner that presents customers with performance and cost transparency.
- Comply with applicable securities, tax, and consumer protection laws to reduce customer risk and protect the customer.

[15] See CCSA Core Principles, available at http://www.communitysolaraccess.org/about-us/.

In collaboration with the Solar Energy Industries Association (SEIA), CCSA also developed the *Residential Consumer Guide to Community Solar*.[16] This guide builds upon SEIA's existing *Residential Consumer Guide to Solar Power*[17] and provides guidelines to help community solar consumers become as informed as possible. It provides a list of key questions that consumers should ask prior to entering a community solar agreement and includes a robust list of additional resources available. In addition, many of our members are also members of SEIA and sign on to the Solar Business Code and adhere to SEIA's existing Complaint Resolution Process.

Processes and regulations already exist that provide consumer safeguards; a number of federal consumer protection statutes apply to community solar, along with existing state and local laws. Adding additional regulations compliance and reporting requirements on top of the existing consumer protection laws will make compliance even more time-consuming and expensive and could frustrate the customer experience.

CCSA recommends the IPA could take a number of steps to ensure satisfactory consumer protection for community solar subscribers.

1. Ensure that consumers are well educated by creating a central repository of information about community solar and solar development in general. Some state organizations, such as NYSERDA may provide helpful guidance;[18]
2. Within that repository, outline the process for consumer complaints and ensure that project owners have the opportunity to respond and fix any problem that customers are experiencing.
3. Develop a standard disclosure checklist that allows community solar subscribers to ensure they are getting the proper disclosures and information they need to evaluate their participation in a community solar project.

20. Should the ABP require the use of a standard disclosure form? If so, what elements should that include?

Because community solar project developers and owners have uniquely different business models, we recommend against the use of a standard disclosure form. Instead, CCSA recommends the use of a standard disclosure checklist, which has been employed in a number

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[16] See SEIA, CCSA Residential Guide to Community Solar, available at http://www.seia.org/sites/default/files/Residential%20Consumer%20Guide%20to%20Community%20Solar%20-%20FINAL.pdf.

[17] See SEIA Consumer Guide to Solar, available at http://www.seia.org/research-resources/residential-consumer-guide-solar-power.

[18] See, e.g. NYSERDA's community solar resources, available at https://www.nyserda.ny.gov/All-Programs/Programs/NY-Sun/Customers/Solar-Options/Community-Solar/Community-Solar-Education and Minnesota's Community Solar Garden Subscriber Resources, available from the Clean Energy Resources Team, at http://www.cleanenergyresourceteams.org/blog/certs-releases-suite-consumer-resources-community-solar-garden-projects.

of other states, such as Minnesota.[19] A checklist allows subscribers to review subscriber agreements and, in the process, educates them about the aspects of participation in community solar that they should understand.

21. Are there examples from other states of model approaches to consumer protection, and/or lessons learned regarding insufficient consumer protections?

Because this is still a nascent market, states have taken various approaches on this topic and no approach has yet emerged as a model to emulate for consumer protection. To our knowledge, community solar has not been cited as a major cause of problems for customers in existing markets, regardless of varying consumer protection laws. While we are aware of some consumer complaints of aggressive marketing efforts in various markets, these types of complaints are typically resolved under existing consumer protection laws and resources. We also support the SEIA Solar Business Code, which promotes "transparency, good faith, and understanding in the U.S. solar energy industry."[20]

III. Community Solar

a. Geographic Considerations

1. Should the IPA consider taking steps to encourage projects to be located geographically closer to subscribers? If so, what steps should be considered?

CCSA does not recommend that the IPA take specific steps to encourage community solar facilities to be located closer to subscribers. In surveys we have seen on community solar issues,[21] and through our members' discussions with their customers, economics are typically much more of a priority to subscribers than their proximity to a facility. Because land is more expensive closer to urban areas, where there will be higher participation demand, and less expensive where there will be less demand, it makes sense to allow projects to be sited where they are most economical. If there is a proximity requirement, it could drive up development costs significantly. Furthermore a subscriber proximity requirement could create a situation in which subscribers in remote parts of the state could not find a project to subscribe to, as development would concentrate near urban centers.

Locational incentives may bring some projects closer to subscribers but that policy decision would raise overall costs for the community solar program. Customers are motivated more by

[19] See Minnesota's Community Solar Garden Checklist, available at http://www.cleanenergyresourceteams.org/sites/default/files/CommunitySolarGarden_DisclosureChecklist_12-11-14_0.pdf.

[20] See SEIA Solar Business Code, available at http://www.seia.org/sites/default/files/SEIA%20Solar%20Business%20Code_Sep2015.pdf.

[21] See, e.g. findings from the Smart Electric Power Alliance's report *What the Community Solar Customer Wants,* p. 14, "Panel location made the least impact on program choice," available for download at https://sepapower.org/knowledge/research/.

the opportunities to save money, and we think the funding would be best spent by increasing the community solar facility options that consumers have.

Furthermore, subscriber proximity requirements or incentives encourage developers to only build projects in densely populated areas. This focus on a narrow consumer base in a smaller geographic area raises consumer protection issues and raises land costs in those targeted areas. Conversely, rural customers see fewer opportunities to subscribe to projects, as their population density is not sufficient to foster enough development. These outcomes would run counter to the statute's geographic diversity requirements.

2. How can geographic diversity be ensured?

CCSA believes that geographic diversity will happen as a matter of course, for a number of reasons, and should not be overly prescribed. Public Act 99-0906 requires that community solar projects be located in the same utility service territory as subscribers so there is already some geographic diversity built into the program. Interconnection costs will naturally create geographic distribution; as upgrade costs for any particular substation are triggered, projects will be sited in other, more cost-effective areas. The DG rebate will also transition to an incentive based on locational value once the 5% NEM cap is hit. Additionally, there is the potential for different REC pricing based on project size, which could further incentivize geographic diversity.

We recommend allowing the program to roll out and for development to occur before pre-determining whether policy interference is needed or appropriate. The program can be reviewed periodically to ensure basic objectives are being met and, if changes need to be made, they can be addressed during the subsequent phase of this procurement program.

b. Project Application Requirements

3. Should Community Solar projects have different application requirements than a comparably sized distributed generation project? What level of demonstration of subscriber interest should be required prior to approving an application from a Community Solar project?

CCSA strongly recommends that community solar projects be required to meet the same application requirements of comparably sized projects. Regardless of how offtake is treated in other segments, however, community solar projects should not be required to prove subscriber interest at the time of the project's application**.** Instead, after projects reserve space in a block, they should prove the project meets specific community solar subscription requirements before receiving any REC payments.

Because community solar projects are unique from other industry segments, there are a number of practical reasons why a minimum subscription level requirement at the time of application would be a poor policy and would likely have unintended consequences.

- Customer acquisition is a significant expense, particularly for residential customers. A requirement to make this investment for a project that has neither been approved nor awarded capacity represents a risk that most experienced and responsible developers and/or their financial investment partners will be unwilling to shoulder. Further, a business's name and reputation could be tainted by marketing and enrolling customers into a project that is ultimately not approved, potentially for reasons out of the developer's control (e.g., multiple developers recruiting customers and submitting applications around the same time period and some being rejected or postponed indefinitely due to exceeding the available capacity of the program). Flexibility is key for ensuring the smooth rollout of the program. Forcing developers into rigid requirements many months before projects become energized will add friction to the market, and ultimately decrease the amount of community solar that gets developed and benefits the ratepayer.

- From a consumer protection perspective, it does not make sense to require the enrollment of customers in a project that may or may not be approved, and which - if approved – would likely not be operating until potentially a year or more following the award. Ideally, a customer should be able to subscribe to a tangible asset (i.e., already operating community solar system), but at the very least there needs to be some legal assurance that the project is approved and moving forward. Project development risk should not be placed on customers; rather, subscribers should be able to choose from among projects and be allowed to subscribe to the project that is farthest along in development.
- At the program level, requiring potentially thousands of customers to enroll in projects that may or may not come to fruition will undoubtedly result in some public frustration and dissatisfaction with the program – dissatisfaction that will naturally be expressed by customers to all parts of the process – the utilities, the Commission, the IPA, and developers.

The IPA should, however place subscription requirements on community solar projects before projects begin to receive payment for RECs – that is, before they are energized. We recommend using the approach that Oregon is taking in their current rulemaking proceeding, which requires developers to have at least 50% of a project's generation subscribed before the project is eligible to commence operation.[22] We further suggest that, by the second payment, at least 90% of a project should be subscribed and maintained for the remainder of the 15-year REC life.

4. How should co-location of Community Solar projects be addressed in light of the definition of community renewable generation projects that is capped at 2 MW?

Colocation can be a valuable tool that allows developers to achieve lower costs for community solar subscribers. Significantly, colocation can reduce zoning and permitting costs that would otherwise be needed for multiple parcels of land. It can also make use of shared interconnection infrastructure, decrease construction costs on a per-MW basis and make more efficient use of valuable land. In order to retain the "community" aspect of these facilities, however, we would recommend placing a limit of 6 MW that can be located by the same developer on the same parcel of land.

[22] See Proposed Rules in AR 603 available at http://edocs.puc.state.or.us/efdocs/HNA/ar603%28ar%20603%20proposed%20rules.pdf%29hna18280.pdf.

c. Community Solar Blocks

5. Should the design approach for blocks for Community Solar vary from that used for Distributed Generation (e.g., size of blocks, criteria for prioritizing applications)?

As we have noted throughout these comments, CCSA recommends against creating separate block criteria or prioritization measures for community solar applicants. Fewer blocks that have little to no fragmentation make the development process more predictable and therefore more cost-effective for developers and their subscribers. Community solar blocks should also accommodate the long development cycle for community solar projects, which includes customer acquisition, permitting, zoning and interconnection.

6. What would be reasonable assumptions to make for the cost of acquiring and maintaining subscribers? How will these costs be expected to vary over time (e.g., the difference between initial subscriber recruitment and managing churn rates)? How will these costs differ between managing residential and commercial subscribers?

As many participants noted during the May 18 Community Solar Workshop, it is notably more expensive to subscribe many residential and small commercial customers than to subscribe a handful of larger C/I customers, both from a customer acquisition and financing perspective.

There is at least one helpful public source available that has published research about these incremental customer acquisition costs and which may provide a helpful benchmark for the IPA.

In late 2016, Rhode Island conducted an analysis to determine the premium cost of a community solar project over a standard solar system for commercial scale (up to 999 kW) and large-scale (1-5 MW) projects. This analysis was used to inform the pricing in their 2017 Renewable Energy Growth program.[23] Based on industry feedback, the consultant averaged the costs of customer acquisition at 25 cents/Watt (as a one-time, initial cost) and 2 cents/Watt/year for customer replacement. We think this is a reasonable assumption for projects with at 50% of capacity dedicated to residential/small commercial (under 25 kW) customers.[24]

CCSA and its members are interested in contributing to a more in-depth discussion of customer acquisition costs.

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[23] See Sustainable Energy Advantage Presentations from September, 2016 (available at http://sos.ri.gov/documents/publicinfo/omdocs/minutes/6154/2016/49211.pdf, Slide 3.) and January 6, 2017, (available at: http://www.ripuc.org/eventsactions/docket/4672-DGBoard-Presentation_1-6-17.pdf, Slides 2-4.)

[24] Because regulators dropped incentives from a 25% premium to 10-12% premium, they may have put this program out of reach for many developers. Currently significant community solar development is not expected in the state as a result.

7. Should the value proposition to the customer for a subscription to a Community Solar project be more, or less, attractive than for a comparable sized DG system at the customer's location?

Community solar subscribers should be allowed to receive an equal value proposition to onsite solar participants. One of the main drivers of community solar policies has been to provide a mechanism for those who cannot host a system onsite to access the benefits of solar energy. Whether they are renters, have lower income, have an unsuitable roof or any other number of reasons, community solar participants should be able to expect a comparable value to those who can host an onsite system.

d. Development Milestones

8. Should the time allowed for Community Solar project development be different than for comparably sized Distributed Generation systems?

As we have noted elsewhere in these comments, community solar projects face longer project development timelines than other similarly sized projects, particularly if those other projects are customer-sited facilities. Behind-the-meter projects face many fewer hurdles in terms of siting, permitting and zoning, since they already have site control and they will likely have lower interconnection costs because they are making use of some or all of the generation on site. CCSA recommends allowing at least 12-18 months for project development, with the ability to extend under certain circumstances, as noted above.

9. What project development milestones should be required to demonstrate sufficient levels of subscriber interest before a contract may be terminated?

Given that the ABP and DG Rebate are front-loaded, the IPA should place reasonable requirements on community solar subscriber allocation prior to receiving funding.

As mentioned above, CCSA supports requiring that projects be 50% subscribed by commercial operation and 90% by the second year of REC payments and for every year thereafter. The 10% buffer will allow community solar owners to manage customer churn and fluctuations in the market. In the event that subscribers do churn out of a facility, a project owner should be allowed a reasonable amount of time to replace that customer. As noted above, CCSA believes that six months is a reasonable amount of time to accomplish this subscriber replacement.

e. Residential versus Commercial Interests

10. What, if anything, should the IPA consider to ensure robust residential participation in Community Solar?

The enacting legislation, SB 2814, specifically calls for the IPA to establish a community renewable generation program that expands access and ensures "robust" participation opportunities for residential and small commercial customers. We anticipate community solar to be the primary vehicle for "community renewable generation project" development and it would therefore be appropriate to ensure smaller-sized customers are given adequate opportunity to participate in the community solar block of the ABP.

As we noted earlier, financing and customer acquisition costs are higher for smaller customers. Without providing special considerations for this customer segment, other states have proven that the market will likely gravitate to lower-cost, larger customers. It is imperative that small customers be able to participate in community solar, as they represent an important segment of the voters and ratepayers of the state. Moreover, because the DG Rebate is rate-based, it is important that one segment of the market is not overly represented among community solar subscribers.

States have taken a variety of approaches to this question, some of which are summarized below:

- Massachusetts: "Community solar," defined as follows, receives a higher SREC value than other virtual net metered solar facilities: At least three participants; No more than 2 participants can receive credits from more than 25 kW of capacity; Combined share of those subscriptions cannot exceed 50% of the total capacity. Virtual net metering is allowed for any net metering customer, with no minimum number of subscribers.
- Rhode Island: No more than 50% of credits may be allocated to an eligible recipient; at least 50% of the credits are allocated to recipients with shares of 25 kW or less.
- New York: For shared "Community Distributed Generation" facilities, no more than 40% of facility's output may go to subscribers with shares sized greater than 25 kW (customers in master-metered multi-tenant buildings may be treated as individual subscribers); At least 60% of facility's output must go to subscribers with shares sized 25 kW or less. Residential and small commercial customers receive more valuable bill credits. Remote net metering is also available for non-residential customers, with only one participant per project.
- Oregon (Proposed draft rules): 50% of the nameplate capacity of every project must be reserved by project managers for subscription or ownership by small commercial and residential participants.
- Maryland: Subscriptions larger than 200 kW must not make up more than 60% of a facility's subscriptions.
- Minnesota: A single subscription cannot exceed 40% of the facility's output. Residential and small commercial customers receive more valuable bill credits.

While our members are somewhat divided on this topic, CCSA is skeptical that this program will be able to "ensure" robust participation among small customers with a simple adder value associated with residential and small customer subscriptions. For example, Minnesota's state program caps individual subscriptions at 40% of a project's generation, similar to Illinois' legislation. Yet, even with a bill credit that is higher (~2-3 cents/kWh[25]) for residential customers relative to general commercial customers, the program has so far resulted in 89% of its total

[25] Northern States Power Company, dba Excel Energy. Minnesota Electric Rate Book – MPUC No. 2. Section 9-64, available at https://www.xcelenergy.com/staticfiles/xe/PDF/Regulatory/Me_Section_9.pdf.

installed capacity (~80 MW) being subscribed by only commercial customers [26] While that program is just getting started, it shows the inclination of companies to gravitate toward lowest cost options for development.

Therefore, we first recommend that the IPA create a small customer requirement on a per-project basis. While "robust" is open to interpretation, we recommend at least 25% of every project be allocated to customers that receive shares of 25 kW or less. Given that residential customers account for about 30% of investor-owned utility kWh sales, and about 90% of actual customers, we believe a 25% per-project carveout would at least ensure that this segment of customers is included in developers' marketing and customer acquisition efforts and thus has an opportunity to participate.

This is not to say that an adder-only approach cannot also produce the desired result of residential and small commercial participation. For an example of an adder-based approach that encourages residential-offtake projects we again point to the direction that Massachusetts took in the SREC II program. This is similar to the approach that Massachusetts is taking in the near-final successor SMART program. Massachusetts allows virtual net metering (VNM) for all customers, whether or not the project qualifies as community solar. As a result, many companies have successfully developed VNM projects with towns and universities and other large offtakers. However, under SREC II, projects that have 50% residential offtake are eligible for a higher SREC factor than other types of projects--including VNM projects with commercial and industrial offtakers.[27] For this reason, many companies have also collectively developed hundreds of MW of residential-offtake community solar projects in the state. Under the forthcoming SMART program, DOER has proposed a 5-cent/kWh adder for community solar projects, which are required to serve 50% residential and small subscribers as described above. As the SMART program has not yet been finalized and implemented, the impact of this adder is not yet known.[28]

We would like to emphasize, however, that it can take significant time and input from stakeholders to ensure that an adder will be set at the right level and work as intended. Additionally, if an adder approach is taken to encourage small customer participation, the IPA should set a high participation threshold in order to receive the adder. We recommend that projects should meet a threshold of at least 50% small customer participation in order to receive an adder. The adder would then be valued based on a project that is 50% subscribed by small customers, and 50% subscribed by commercial customers.

[26] Northern States Power Company, dba Excel Energy. Monthly Update Community Solar Gardens Docket No. E002/M-13-867. (June 15, 2017), available at https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={05DBE5B1-7465-49AB-90CB-0222CF704B17}&documentTitle=20176-132832-01.

[27] See DOER website, About the Solar Carve-Out II Program, available at http://www.mass.gov/eea/energy-utilities-clean-tech/renewable-energy/solar/rps-solar-carve-out-2/about-solar-carve-out-ii.html.

[28] See the SMART program draft rules, available at http://www.mass.gov/eea/docs/doer/rps-aps/225-cmr-20-00-draft.pdf.

Because there is clearly a demand for community solar in Illinois among all customer classes, we want to ensure that all of them have the opportunity to participate in a community solar project. We also know that the majority of Illinois residents and businesses cannot host an onsite solar facility for a number of reasons. As a result, we suggest using the remaining 25% of ABP DG capacity that is available at the IPA's discretion to help fill this sizable demand. This discretionary category could be used in a number of ways. For example, a portion of the unallocated capacity could be designated as a secondary community solar option for projects that are not targeted in the primary community solar block. Some capacity could also be reserved and used at a later date to help spur development in areas that are underrepresented.

11. Should REC pricing vary based on the portion of the project that is residential? How can this be verified, and what would be required over time to ensure ongoing residential participation?

A sliding scale based on each individual small customer's participation would be difficult for developers to maintain and for program administrators to continuously verify, as discussed in the previous response. Instead, we recommend that, if an adder is to be provided upfront it be incorporated in the REC payment and be contingent on at least 50% of the project's subscribed capacity being allocated to subscriptions of 25 kW or less. This limit would need to be maintained for the life of the REC contract or face penalties through clawback provisions. Regardless of how residential participation is incentivized (either with an adder or as a requirement), CCSA advocates for an annual self-certification process with audits by the program administrator to ensure that these targets are being hit.

12. Should project application/viability requirements be different based on the mix of residential and commercial customers?

As we noted above in our response to Question 3 in the Community Solar section, project application requirements should be similar to non-community solar projects of a similar size and this is the case regardless of the mix of subscribers attributed to the project.

13. Are there additional considerations that should be made for projects that are entirely subscribed with commercial customers, or entirely subscribed with residential customers?

As we noted above in our response to question 10, we believe there is clearly a strong interest among developers to build both projects that serve a mix of residential and commercial customers and those that focus exclusively on commercial customers. We strongly recommend using some or all of the IPA's discretionary ABP tranche to allow both types of community solar business models to participate in the market.

Respectfully submitted on June 27, 2017,

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