

STATE OF ILLINOIS
ILLINOIS COMMERCE COMMISSION

Illinois Power Agency	:	
	:	
Petition for Approval of the IPA's 2022	:	22-0231
Long-Term Renewable Resources	:	
Procurement Plan pursuant to Section	:	
16-111.5(b)(5)(ii) of the Public Utilities Act.	:	

ORDER

July 14, 2022

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ORDER

By the Commission:

I. INTRODUCTION

On March 21, 2022, the Illinois Power Agency (“IPA” or “Agency”) filed with the Illinois Commerce Commission (“Commission”) a verified Petition for Approval of its 2022 Long-Term Renewable Resources Procurement Plan (“LTRRPP,” “Plan,” or “2022 Plan”) pursuant to Section 16-111.5(b)(5)(ii) of the Public Utilities Act (“PUA” or “Act”). The 2022 Plan is the IPA’s proposal for the procurement of renewable energy credits (“RECs”) for Ameren Illinois Company d/b/a Ameren Illinois (“Ameren”), Commonwealth Edison Company (“ComEd”), and MidAmerican Energy Company (“MidAmerican”) under Sections 1-56(b) and 1-75(c) of the Illinois Power Agency Act (20 ILCS 3855/1-56(b) and 1-75(c)) (“IPA Act”) and Section 16-111.5(b)(5) of the PUA. 220 ILCS 5/16-111.5(b)(5).

The IPA’s Petition states that the 2022 Plan was developed pursuant to Section 1-75(c)(1)(A) of the IPA Act as modified by Public Act 102-0662 (“P.A. 102-0662”), which required that “no later than 120 days after” the September 15, 2021 effective date of P.A. 102-0662, “the [IPA] shall release for comment a revision to the long-term renewable resources procurement plan, updating elements of the most recently approved plan as needed to comply” with P.A. 102-0662’s new requirements. In accordance with Section 16-111.5(b)(5)(ii)(C) of the PUA, the Commission is required to enter its Order “confirming or modifying” the Plan within 120 days after this filing - July 19, 2022.

The Administrative Law Judge (“ALJ”) granted the following Petitions to Intervene: Solar Energy Industries Association, the Coalition for Solar Access, and the Illinois Solar Energy Association (together the “Joint Solar Parties” or “JSPs”); Clean Grid Alliance (“CGA”); Ameren; NRG Companies (“NRG”); Environmental Law & Policy Center and Vote Solar (together the “Joint Non-Governmental Organizations,” “Joint NGOs,” or “JNGOs”); City of Chicago (the “City”); Little Village Environmental Justice Organization (“LVEJO”); Natural Resources Defense Council (“NRDC”); Summit Ridge Energy, LLC (“Summit Ridge”); SolAmerica Energy, LLC (“SolAmerica”); TPE Development LLC d/b/a TurningPoint Energy; Arcadia Power, Inc. (“Arcadia”); United States Solar Corporation (“US Solar”); ComEd; and the Retail Energy Supply Association (“RESA”).

As required by subsection (ii)(C) of Section 16-111.5(b)(5) of the Act, Objections to the Plan (“Obj.”) were due April 4, 2022 and were filed by the following parties: LVEJO, the JSPs, SolAmerica, CGA, the City, the Joint NGOs, Staff of the Commission (“Staff”), Arcadia, NRG, ComEd, and US Solar. Within 21 days after the filing of the 2022 Plan, the Commission is required to determine whether a hearing is necessary. See 220 ILCS 5/16-111.5(b)(5)(ii)(C). On April 11, 2022, the ALJ issued a ruling waiving the hearing in this matter and adopting a schedule for verified comments.

Powerflex, LLC (“Powerflex”) filed Objections to the 2022 Plan on April 13, 2022 beyond the statutorily-mandated period for objections; those Objections are not considered.

Response Comments (“Resp.”) were filed on April 26 and 27, 2022 by the following parties: LVEJO, the JSPs, Summit Ridge, Ameren, Staff, NRG, the Joint NGOs, the IPA, and ComEd. Reply Comments (“Rep.”) were filed on May 11, 2022 by the following parties: Ameren, the JSPs, Staff, the Joint NGO, CGA, the City, the IPA, ComEd, and NRG.

The Proposed Order was served on June 8, 2022. Briefs on Exceptions (“BOEs”) were filed on June 17, 2022, by the following parties: SolAmerica, Ameren, the JSPs, LVEJO, Staff, Summit Ridge, the City, ComEd, the Joint NGOs, the IPA, and NRG. Reply Briefs on Exceptions (“RBOEs”) were filed on June 24, 2022, by the following parties: LVEJO, Staff, the JSPs, the Joint NGOs, Ameren, ComEd, SolAmerica, NRG, the IPA, and the City.

II. CHAPTER 2 STATUTORY REQUIREMENTS OF THE PLAN

A. Section 2.6.2.4 Installer & Labor Requirements

1. Staff’s Position

Staff notes that the 2022 Plan states as follows regarding “Qualified Person” under the Commission’s rules implementing Section 16-128A of the Act.

Any parties seeking to develop new photovoltaic projects in Illinois should be aware of the Commission’s Part 461 rules (governing installers of utility-scale photovoltaics) and Part 468 rules (governing distributed generation installers) and certification process more generally. The definition of “Qualified person” may preclude the inclusion of self-installed new photovoltaic projects in the Adjustable Block Program (unless the self-installer meets the “qualified person” definition).

Staff takes issue with LTRRPP’s statement that unless a self-installer meets the definition of “qualified person” in the definition under Part 468, the self-installer’s project is precluded from inclusion in the Adjustable Block Program (“ABP”). As set forth in the Plan, Section 1-75(c)(7) of the IPA Act provides that RECs from “new photovoltaic projects or new distributed renewable energy generation devices [. . .] must be procured from devices installed by a qualified person in compliance with the requirements of Section 16-128A of the [PUA] and any rules or regulations adopted thereunder.” LTRRPP

at 33. The Commission's rules implementing Section 16-128A provide that self-installers are not subject to Part 468. Therefore, Staff argues that it is not true that the definition of qualified person in the Commission's rules may preclude the inclusion of self-installed projects unless the installer meets the definition of "qualified person." So that the Plan is consistent with Section 16-128A and Part 468, Staff proposes to delete the second sentence of the above-quoted paragraph. Staff Obj. at 3-4.

2. IPA's Position

The IPA notes that while allowing self-installed project participation would constitute a shift in program requirements, the ABP exists to support Illinois residents and businesses seeking to adopt solar energy. Allowing self-installed project participation is within the spirit of that objective. As self-installed projects would still need to meet requirements found in the Plan's Chapter 7 on minimum batch size and Approved Vendor submittal for program participation, a self-installed project would offer no greater risk of having a less sophisticated or capable REC delivery contract counterparty. IPA Rep. at 5.

3. Commission Analysis and Conclusion

The Commission adopts the agreement between the IPA and Staff to delete the sentence in the 2022 Plan that would preclude self-installers from participating in the ABP. Although the Commission accepts the agreement, the Commission does not entirely agree that the statutory requirement that installations be done by qualified persons does not apply to self-installers. Part 468 exempts self-installers from the certification requirements, but not the requirement to be a qualified person. The Commission agrees with the IPA's assertion that allowing self-installation is consistent with the spirit of the ABP.

B. Section 2.7.4.1 Indexed REC Price Structure

1. Staff's Position

Staff notes that the 2022 Plan states:

Under the Indexed REC pricing structure, a resulting REC price constitutes 'the difference resulting from subtracting the strike price from the index price for that settlement period,' with the index price representing 'the real-time energy settlement price at the applicable Illinois trading hub.' If the difference in this equation results in a positive number, then the Buyer pays that amount per REC to the Seller.

LTRRPP at 40. Staff believes the Plan has this backwards. Instead, it should be if the number is negative, then the buyer pays the seller the absolute value of the difference. Rather than summarize what the statute says, for clarity the Plan should just quote what the statute says with one clarification that the REC counterparty is the "Buyer." Staff Obj. at 5.

2. IPA's Position

The IPA states that Staff correctly notes that two concepts were transposed in this Section's explanation; the Buyer instead pays Seller in the case of a negative value

resultant from subtracting the strike price from the index price. Thus, if the strike price (i.e., the bid price) is \$50, and the index price is \$40, then subtracting \$50 from \$40 results in a REC price of \$10. Staff provides corrective changes to this Section, and the IPA supports Staff's proposed changes. IPA Rep. at 5.

3. Commission Analysis and Conclusion

The Commission finds that Staff's proposed correction correctly implements the statute. It is adopted.

C. Section 2.8.1.1 Adjustable Block Program – Projects

1. ComEd's Position

In the 2022 Plan, the IPA identifies a new issue that arose during Plan development regarding public universities and ABP eligibility. ComEd states that it is not clear what constitutes a "public university utility." At a minimum, it is critical that the IPA clarify that the public university must be a retail customer of an electric utility (or otherwise take retail electric service from a municipal utility or rural electric cooperative). ComEd Obj. at 3-4.

In its Response Comments, the IPA clarified that under the LTRRPP, a "public university utility" will be required to be a retail customer of an electric utility in order to participate in the ABP and that the IPA will seek Commission approval only for projects satisfying this requirement. ComEd appreciates and supports the IPA's clarification. ComEd Rep. at 3-4.

2. Staff's Position

Staff agrees with ComEd that interpretive issues should be avoided where possible. Staff Resp. at 17. With the IPA's clarification, Staff notes that this issue appears to be uncontested. Staff Rep. at 22.

3. IPA's Position

As used within Section 2.8.1.1, the IPA confirms that a "public university utility" must also be a retail customer of an electric utility for its projects to qualify for the ABP and seeks Commission authorization for participation only by projects meeting this requirement. IPA Resp. at 6.

4. Commission Analysis and Conclusion

The Commission agrees with the clarification provided by the IPA in its Response Comments that a "public university utility" must also be a retail customer of an electric utility for its projects to qualify for the ABP. The Commission further finds that it is appropriate that only projects meeting this requirement should be authorized to participate.

III. CHAPTER 3 REC PORTFOLIO, RPS GOALS, TARGETS, AND BUDGETS

A. Section 3.3.4 Overall REC Procurement Targets and Goals – REC Gap

1. Staff's Position

Staff states that Table 3-5 of the Plan should use the phrase "Overall Renewable Portfolio Standard ("RPS") Goal" rather than "Overall RPS Target" in the ninth column header. Given the extent to which the 2022 Plan goes to differentiating targets (REC

numbers) and goals (overall % objectives), it seems like the Plan should then use “Goal” in the ninth column header (and not “Target”) as the column seems to be referencing the overall percentage objectives. Staff Obj. at 6. Given the IPA’s Response Comments, Staff no longer objects to the Plan on this issue. Staff Rep. at 6.

2. IPA’s Position

The IPA explains that in Section 3.1 of the 2022 Plan it states that “the [IPA] considers a ‘goal’ to be an overall percentage of load to be procured in the form of RECs,” while “a ‘target’ is the number of RECs for a specific procurement event or program based upon a specific goal or numerical mandate.” While Staff is correct that the column in question provides REC quantities resultant from the application of Section 1-75(c)(1)(B)’s RPS goals, because the resultant numbers are the number of RECs required to meet those goals (albeit an “overall” number, rather than a number for any specific program or procurement), this column is properly labeled and should not be changed. IPA Resp. at 6-7.

3. Commission Analysis and Conclusion

The Commission notes that with the IPA’s explanation, Staff no longer objects to this column. The Commission finds Table 3-5 appropriately labeled.

B. Section 3.4.6 Expenses and Available RPS Budgets

1. CGA’s Position

CGA notes that the Projected RPS Expenses for utility-scale projects in Table 3-11 are based on “the average REC price from the Agency’s last procurement for each resource type.” LTRRPP at 83. CGA argues, however, that P.A. 102-0662 requires the use of a forward price curve to evaluate the annual budget. 20 ILCS 3855/1-75(c)(1)(G)(v)(3); CGA Obj. at 3.

Furthermore, the LTRRPP states that:

As the Agency prefers not to suggest indicative prices for future procurements, these prices will serve as a proxy until more detailed pricing information is available after the completion of future procurement events.

LTRRPP at 82. CGA states the IPA did not use a forward price curve in the 2022 Plan and this quote indicates the IPA will not use the forward curve required in Section 1-75(c)(1)(G)(v)(3) of the IPA Act for modeling in future LTRRPPs. CGA Obj. at 3-4. The IPA’s Response Comments regarding actions it will take in future Plans has sufficiently addressed CGA’s objection. CGA Rep. at 5-6.

2. Staff’s Position

Staff does not support CGA’s objection. The 2022 Plan states that the Act “... requires that the annual cost of the contract be quantified utilizing an industry-standard, third-party forward price curve for energy at the appropriate hub or load zone.” LTRRPP at 120. The 2022 Plan then sets forth how the forward price curve will be used. Based upon Staff’s understanding of the Plan, the IPA Act is being followed and therefore, CGA’s objection should be rejected. Staff Resp. at 15.

3. IPA's Position

The IPA clarifies that it does plan to use a forward price curve for future procurement plans in estimating budget impacts from Indexed REC contracts but explains further why a forward price curve was not used for this procurement plan. Section 1-75(c)(1)(G)(v)(3) provides for the use of a forward price curve for determining expected budget impacts. The IPA explains that no Indexed REC contracts presently exist, as the first procurement using this structure is scheduled for May 2022. Thus, the IPA used proxy values for future Indexed REC contract costs based on REC prices for utility-scale wind, utility-scale solar, and brownfield site photovoltaic project fixed-price REC delivery contracts resultant from procurements conducted since the passage of P.A. 99-0906. IPA Resp. at 8-9.

CGA does not appear to take issue with this decision for the present Plan, as its request to the Commission concerns only "future procurement plans." Once Indexed REC procurements have been conducted and pricing information is available from this new procurement structure, the IPA plans to utilize a forward price curve and estimate RPS budget impacts using actual prices observed through competitive procurement events. IPA Resp. at 9.

4. Commission Analysis and Conclusion

The Commission finds the IPA's use in the 2022 Plan of proxy values based on REC prices for utility-scale wind, utility-scale solar, and brownfield site photovoltaic projects from fixed-price REC delivery contracts to be appropriate. For future LTRRPPs, the IPA plans to comply with the requirement in the IPA Act that budget impacts be determined through the use of future price curves. The Commission does not find that any change needs to be made to the 2022 Plan regarding this issue.

IV. CHAPTER 5: COMPETITIVE PROCUREMENTS

A. Section 5.4.3: Labor, Diversity and Equity Requirements

1. IPA's Position

While not expressly addressed in its 2022 Plan, the IPA has become aware of an additional item for which Commission approval is sought. Section 1-75(c)(1)(Q)(1) of the IPA Act requires that projects that execute a contract for RECs through a program or procurement under Section 1-75 comply with "the prevailing wage requirements" of the Prevailing Wage Act ("PWA"). 820 ILCS 130/1 *et seq.* Those requirements state that "[n]ot less than the general prevailing rate of hourly wages for work of a similar character on public works in the locality in which the work is performed ... shall be paid to all laborers, workers and mechanics." 20 ILCS 3855/1-75(c)(1)(Q)(1). However, the public interest criteria in Section 1-75(c)(1)(I) of the IPA Act expressly contemplates that some projects subject to Section 1-75(c)(1)(Q)(1)'s prevailing wage requirements will not be located in Illinois. The IPA also understands that the Illinois Department of Labor may not be able to enforce Illinois prevailing wage requirements on labor conducted in other states. IPA Rep. at 9-10.

To prevent perverse incentives for locating new renewable energy projects outside of Illinois, and to ensure that "the prevailing wage requirements" of the PWA are met even if the Department of Labor may be limited in non-Illinois enforcement, the IPA proposes

interpreting Section 1-75(c)(1)(Q)(1) as also carrying a qualitative eligibility requirement related to fair wages paid for labor on all renewable energy projects bidding into IPA procurements (enforced as a REC delivery contract term). To implement Section 1-75(c)(1)(Q)(1), the IPA proposes requiring applicant projects located in adjacent states to demonstrate, at minimum, wage parity with the prevailing wage requirements in Illinois. IPA Rep. at 11.

In making this proposal, the Agency seeks not only Commission approval for this approach as part of its 2022 Long-Term Plan, but also an interpretation from the Commission for its May 2022 Indexed REC delivery contract which allows for prevailing wage requirements outlined in that contract instrument to be applied to adjacent state projects in this manner. IPA Rep. at 11.

In addition to the above issue, the IPA also seeks Commission approval of a clarification to the outlined requirements for Project Labor Agreements in the filed Plan. As noted in Section 5.4.3 of the Long-Term Plan, Section 1-10 of the IPA Act includes a definition of “project labor agreement” that contains five required elements of all project labor agreements. The final item listed states that:

provisions for minorities and women, as defined under the Business Enterprise for Minorities, Women, and Persons with Disabilities Act, setting forth goals for apprenticeship hours to be performed by minorities and women and setting forth goals for total hours to be performed by underrepresented minorities and women.

20 ILCS 3855/1-10. The IPA proposes clarifying language as to how entities may comply with this requirement from Section 1-10 of the IPA Act. The IPA requests that the Commission approve an interpretation that includes a description of the efforts the entity will take or has taken to achieve such goals, including recruitment of minorities and women into apprenticeship roles. IPA Resp. at 12.

2. CGA’s Position

CGA accepts the IPA’s proposal. CGA Rep. at 4.

3. Commission Analysis and Conclusion

The Commission notes that no party objects to the IPA’s proposals. The IPA seeks Commission approval for its approach to enforcing the prevailing wage requirements of the IPA Act as part of its 2022 Long-Term Plan and also for its May 2022 Indexed REC delivery contract. In addition, the IPA requests to include clarifying language in the LTRRPP as to how entities will comply with Section 1-10 of the IPA Act. The IPA’s requested approvals are reasonable and are hereby granted.

B. Section 5.7.1 Credit Requirements

1. CGA’s Position

In its description of Credit Requirements, CGA notes that the IPA proposes to permanently ban a competitive supplier and its facilities if it either defaults on a contract for economic reasons or misrepresents its eligibility to participate in the procurement. LTRRPP at 126. CGA argues that a permanent ban is extreme. The ban should be

limited in time because the IPA has the ability to cure a default through future procurements, and performance assurance payments are in place to discourage defaults. CGA Obj. at 4-5.

CGA recommends that the penalty for a first offense be a suspension from participating in future competitive REC procurements for up to 2 years. A second violation should merit a 3-year suspension from participating in competitive REC procurements. CGA Obj. at 5.

CGA further notes that the IPA proposes to evaluate such occurrences as follows: “the Agency will review all available facts and evidence whether the supplier or applicant made a good faith effort at compliance and whether non-compliance resulted from circumstances outside of that party’s control.” LTRRPP at 126. CGA notes that the term “economic reasons” is undefined and overly broad. The range of potential reasons the IPA is trying to or could capture in this term increases risk to the competitive supplier which will cause a non-market related inflation to the bid price. CGA Obj. at 5-6.

Also, the LTRRPP does not provide exemptions to this default, even for matters beyond the competitive supplier’s control. First, CGA recommends the ‘economic reason’ ban not apply to instances in which a project cannot perform due to supply chain issues, or if the RPS Budget is exceeded in a Delivery Year. Another instance that should be exempt from the ‘economic reasons’ ban proposed in the LTRRPP is a competitive supplier’s sale of RECs to other entities in the event there is insufficient money in the RPS Budget and the utilities cannot pay for RECs to be delivered. Any shortfall of the RPS Budget is not caused by the competitive supplier nor can it be corrected by the competitive supplier. CGA recommends that these two instances be exempt from the ‘economic reasons’ ban because they are beyond the competitive supplier’s control. CGA Obj. at 6-9.

CGA states that the IPA’s response to this objection is sufficient to resolve the matter; however, at some point a rule on the review process related to economic default determinations may be warranted. A rule would clarify any process the IPA may initiate for collecting information and making a determination regarding whether a Seller’s action was an economically motivated default, or a misrepresentation was accidental or intentional. CGA Rep. at 6.

2. Staff’s Position

Staff agrees with CGA that an automatic permanent ban is too extreme. Instead, Staff supports allowing the IPA the discretion to consider penalties up to the Plan’s permanent ban for the second offense. Staff could support CGA’s alternative, but with the additional ability for the IPA to impose harsher penalties for good cause. Staff Resp. at 16.

CGA recommends the Plan explicitly state what the IPA means by economic reasons. Staff does not support CGA’s Objection. Staff believes the IPA should have some discretion in determining whether a contract was defaulted on for economic reasons. If the IPA is required to define “economic reasons” in the LTRRPP it could lead to the creation of unreasonable loopholes for parties to default on contracts for “economic

reasons" but not experience any consequence for that economic default on the contract. Staff Resp. at 16.

Staff also notes that CGA takes issue with the Plan for not allowing any exemptions from a permanent ban due to economic default on a contract. Staff does not support CGA's objection. The exemptions are not necessary. CGA fails to recognize that the contract between the suppliers and utilities would address the types of exemption scenarios suggested by CGA. Staff Resp. at 17.

Staff notes that the IPA provided clarification of voluntary default on contracts for economic reasons versus defaults due to circumstances beyond the supplier's control. With that clarification, Staff now supports the Plan as clarified by the IPA's Response Comments. Staff Rep. at 20-21.

3. IPA's Position

CGA objects to the IPA's proposal in Section 5.7.1 barring developers who voluntarily default on a REC delivery contract for economic reasons or misrepresent their eligibility from participation in future procurement events. IPA Resp. at 13.

For the IPA, the ability to take this action is vital. If the IPA is limited to only using posted collateral as a means to ensure performance—such as by setting a collateral level so high as to deter voluntary economic default, given the cost of collateral forfeiture—it will inherently favor larger, well-capitalized developers better suited to meet high collateral requirements. As the IPA disfavors creating barriers to participation by smaller firms, “the level of collateral must be low enough to encourage participation (especially from small businesses and other newer market entrants) and high enough to discourage suppliers from voluntarily defaulting on contracts for economic reasons.” IPA Resp. at 13.

In response to CGA's concerns, the IPA offers the following clarification: in discussing “suppliers and associated facilities who voluntarily default on contracts for economic reasons,” the IPA is specifically referencing voluntary default on an Indexed REC contract because the developer elects to sell its RECs to another buyer under circumstances within that developer's control—specifically, because of a more attractive REC price or contract structure offered by a different buyer. Should default occur because of circumstances outside of that entity's control—including “the RPS budget being exceeded in a delivery year,” unanticipated significant interconnection costs making development uneconomic, or other unforeseeable costs or circumstances sufficient to significantly alter project economics—then suspension would not be warranted. As with any standard applied to possible future fact patterns, the IPA cannot anticipate all such circumstances in its Plan and outline whether each would be considered voluntary economic default. IPA Resp. at 14-15.

Additionally, the IPA believes a two-year suspension for voluntary economic default is reasonable, with a three-year suspension for a second such occurrence. However, for entities that “misrepresent their eligibility to participate in a procurement event,” the IPA believes that discipline should instead be informed by the facts underpinning those misrepresentations. Should the IPA find that a firm acted in bad faith in providing erroneous information as part of its submittal, engaged in fraud, or otherwise knowingly made material misrepresentations to the Procurement Administrator, then a

ban on eligibility for state-administered incentive funding should be commensurate with the circumstances surrounding that suspension. IPA Resp. at 15.

4. Commission Analysis and Conclusion

The Commission sees the parties to be mostly in agreement. The LTRRPP should be modified to reflect that an initial two-year suspension term is generally reasonable, but the IPA should have discretion for a harsher penalty for a second default for economic reasons.

The Commission also notes the IPA's language that confirms it will take into account all circumstances when making its determinations regarding penalties. CGA states that this is sufficient to satisfy its request that specific exemptions be adopted to the IPA's proposal to impose penalties for voluntary defaults on contracts for economic reasons.

V. CHAPTER 6 SELF-DIRECT RENEWABLE PORTFOLIO STANDARD COMPLIANCE PROGRAM

A. Section 6.2.1. Common Parents

1. NRG Companies' Position

NRG Companies argue that the IPA's proposed LTRRPP would improperly limit eligibility for the Self-Direct Program. According to the IPA, a customer must meet the statutory minimum volumetric threshold of 10,000 kilowatt ("kW") of demand in the prior twelve months (in the aggregate or at a single site) within a single utility region. See 20 ILCS 3855/1-75(c)(1)(R)(1). The IPA admits that the statute does not contain an express statement that combining across ComEd and Ameren service territories to meet the 10,000 kW size requirement is prohibited. Nevertheless, the IPA requests that the Commission read such a limitation into the statute. NRG Obj. at 4-5.

The IPA suggests that the Commission should read the term "either" into the statute. The IPA asserts that eligible customers must be either one or the other. NRG Companies argue that if the General Assembly had included the term "either," there would be a clear indication that there were only two options for compliance. This is not the case. To the contrary, limiting eligibility is directly contrary to the plain meaning of the definition of "retail customer," which provides that "multiple retail customer accounts under the same corporate parent may aggregate their account demands to meet the 10,000 kW threshold." The General Assembly expanded the definition to include additional customers who have a significant amount of total usage, which means they are making substantial RPS payments and likely are more sophisticated; it would be improper for the IPA to turn around and read language into the statute that would limit eligibility. NRG Rep. at 10-11.

NRG Companies interpret the definitions to mean that any retail customer served by ComEd or Ameren with a single or aggregated load that exceeds 10,000 kW in peak demand in one utility region is an eligible self-direct customer and may combine additional accounts that are served by the other utility into its Self-Direct Program application even if that portfolio of accounts does not meet the 10,000 kW peak demand threshold. NRG Rep. at 12.

NRG Companies also complain that the IPA fails to recognize the authority given to municipalities and other public agencies under the Intergovernmental Cooperation Act ("IGCA"). See 5 ILCS 220/1, *et seq.* Section 3 of the IGCA states, in relevant part: "Intergovernmental cooperation. Any power or powers, privileges, functions, or authority exercised, or which may be exercised by a public agency of this State may be exercised, combined, transferred, and enjoyed jointly with any other public agency of this State and jointly with any public agency of the other State or of the United States to the extent that laws of such other state or of the United States do not prohibit joint exercise or enjoyment and except where superficially and expressly prohibited by law." 5 ILCS 220/3. In sum, the IGCA requires that a contractual opportunity for one municipality must be shared among any number of other municipalities. NRG Obj. at 5.

NRG Companies assert that the IGCA mandates that the public agencies be allowed to act in combination with each other "except where specifically and expressly prohibited by law." 5 ILCS 220/3. There is no such prohibition in the IPA Act or the PUA. NRG respectfully requests that the Commission revise the LTRRPP to recognize that a group of municipalities can certify their qualification under the provisions of the IGCA by submitting a copy of the executed agreement between the municipalities participating in the intergovernmental cooperation group as well as a copy of a utility-issued historical consumption report that shows a level of non-coincident demand greater than 10,000 kW in the twelve (12) billing cycles prior to application. NRG Obj. at 6.

2. Staff's Position

Staff argues that the IPA Act explicitly authorizes the combination of multiple individual accounts under a single corporate parent, in order to meet the minimum annual usage threshold for eligibility. 20 ILCS 3855/1-75(c)(1)(R)(1). The statute includes no language limiting this "single corporate parent" provision to a single utility service territory. Staff Resp. at 9.

Staff notes that the IPA admits that Section 1-75(c)(1)(R) does not contain an express statement prohibiting combining accounts across utility service territories to meet the 10,000 kW eligibility requirement for the Self-Direct Program. The statute, however, does establish a methodology for determining eligibility that differs between utility service territories. Staff explains that while eligibility in ComEd's territory is determined based on "total highest 30-minute demand," eligibility in Ameren's territory is determined based on "total highest 15-minute demand." 20 ILCS 3855/1-75(c)(1)(R)(1). The IPA also notes that credits offered back to customers through the Self-Direct Program vary based on that utility's actual RPS expenses-which likewise differ by utility. For those reasons, the IPA believes the only supportable reading is that demand may only be aggregated for individual accounts with a common parent located in a single utility service territory. Staff Rep. at 14-15.

Staff notes that a similar opt-out provision exists in the Commission's energy efficiency programs. 220 ILCS 5/8-103B(l)(3). That opt-out provision, as established by statute, also varies eligibility across service territories. *Id.* Additionally, like the RPS expenses, charges under the energy efficiency program are based on each utility's energy efficiency program expenses and utility specific budget caps, and thus vary across utility territories. See 220 ILCS 5/8-103B(d)(1). Therefore, Staff agrees with NRG Companies

that accounts with a common corporate parent should be allowed to aggregate demand across utility service territories for purposes of establishing Self-Direct Program eligibility. Staff Rep. at 15.

NRG Companies also argue that the Self-Direct Program, as set forth in the Plan, fails to recognize the authorities given to municipalities and other public agencies under the IGCA. Staff notes that the IGCA states, in part, that:

Any power or powers, privileges, functions, or authority exercised or which may be exercised by a public agency of this State may be exercised, combined, transferred, and enjoyed jointly with any other public agency of this State and jointly with any public agency of any other state or of the United States to the extent that laws of such other state or of the United States do not prohibit joint exercise or enjoyment and except where specifically and expressly prohibited by law.

5 ILCS 220/3; Staff Resp. at 10-11.

The Illinois Appellate Court has explained that this statute "permits two or more public agencies to act jointly in the exercise of any power possessed by one of those agencies." *Oak Lawn v. Commonwealth Edison Co.*, 163 Ill. App. 3d 457, 460 (1st Dist., 1987). Staff recommends that the Commission reject NRG Companies' argument regarding the ability of municipalities that are not themselves eligible to participate in the Self-Direct Program to participate jointly in a REC agreement along with municipalities that are eligible to participate. The IGCA allows municipalities to, in effect, share their "powers, privileges, functions, or authority exercised . . ." with other municipalities. 5 ILCS 220/3. Here, the "powers, privileges, functions, or authority . . . which may be exercised" by a municipality under the Self-Direct Program is the ability to purchase and retire RECs representing at least 40% of the municipality's annual usage in exchange for "a reduction in charges levied . . . to support the RPS." LTRRPP at 61-62. The Self-Direct Program, however, does not allow an eligible customer to acquire or retire RECs on behalf of another customer, or to reduce another customer's RPS charges. Therefore, the authority granted by the Self-Direct Program cannot be shared in the way that NRG Companies suggest. Staff Resp. at 11-12.

3. IPA's Position

The IPA notes that NRG Companies object to the IPA's determination that the statutory minimum 10,000 kW customer size be applied by utility service territory. NRG is correct that Section 1-75(c)(1)(R) does not contain an express statement that combining accounts across ComEd and Ameren service territories to meet the 10,000 kilowatts size requirement is prohibited. Instead, P.A. 102-0662 implements a regime through which customer size is determined utilizing different methodologies across the two utility service territories, utilizing a definition which does expressly parse customers by utility. See 20 ILCS 3855/1-75(c)(1)(R)(1). Under this definition, the IPA argues that eligible customers must be either one or the other. IPA Resp. at 16.

Additionally, the IPA explains that credits offered back to customers through the Self-Direct Program vary based on that utility's actual RPS expenses-which likewise differ

by utility given that Section 1-75(c)(1)(E) of the IPA Act authorizes maximum ratepayer collections based on each participating utility's 2009 rates. Each utility also has RPS payment obligations based on that particular utility's REC delivery contracts, with the proportionate annual level of those expenses also varying by utility depending on contracted project energization timelines, contract payment structure, and other RPS-funded obligations. Given the duality in the definition of an "eligible self-direct customer," the differences in qualification by utility, and the differences in crediting by utility, the IPA believes the only supportable reading of Section 1-75(c)(1)(R) is that each "eligible self-direct customer" may meet its size qualification only by meeting the 10,000 kW threshold within an individual utility service territory. IPA Resp. at 16-17.

The IPA notes that Staff points to how an opt-out provision, which the Self-Direct Program is not, works in the context of the Commission's energy efficiency programs. Staff explains that under that program, eligible customers may opt out even where their facilities span more than one utility's service territory. Even setting aside the fact that Staff is discussing a completely different program, this statement fails to address the relevant issue. Nothing in the Plan says that a large corporate customer cannot participate simply because it has "facilities span[ning] more than one utility's service territory." The Plan simply says that the load from facilities in different service territories cannot be aggregated—because the very definition used in the law states that a customer meets either one utility's threshold "or" another utility's threshold. If a company has facilities in multiple service territories and meets the threshold independently in each service territory, it is eligible to participate in each utility territory. IPA Rep. at 9-10.

Second, NRG Companies provide an argument that multiple unaffiliated municipalities' municipal load should be combined to meet this 10,000 kW threshold based on NRG's interpretation of the IGCA. At issue is a provision in Section 1-75(c)(1)(R) that allows "multiple retail customer accounts under the same corporate parent" to "aggregate their account demands to meet the 10,000 [kW] threshold." The IPA cannot contemplate a reading of the statute that would allow for aggregation of multiple municipal accounts across different municipalities. Quite clearly, any affiliation between municipalities - whether by contract or through equivalency provided under the IGCA - does not transform the character of those municipalities' relationship with each other in a way analogous to having the "same corporate parent." Thus, the IPA cannot accept NRG Companies' argument that one municipal large customer potentially qualifying for a bill credit simply carries over to municipal accounts in other municipalities that do not. IPA Resp. at 17-18.

NRG Companies quote Section 3 of the IGCA and reads it to mean that a contractual opportunity for one municipality must be shared among any number of other municipalities. The IPA argues that NRG Companies are wrong in multiple respects. First, the large customer self-direct bill program is not itself a contractual opportunity. Nothing about Section 1-75(c)(1)(R) itself offers an opportunity for contracting; any large customer is already free to engage in contracting for RECs - a process is in no way limited by Section 1-75(c)(1)(R)-but only qualifying customers who do obtain qualifying REC delivery contracts may receive discounted tariffed RPS collections by privately obtaining a qualifying long-term REC delivery contract. As the Self-Direct Program simply provides

discounts if predicate criteria are met, that opportunity is not a contractual opportunity; it is a utility bill cost reduction. IPA Resp. at 18-19.

Second, and more importantly, the presence of a minimum size threshold within Section 1-75(c)(1)(R) would mean that a municipality whose combined municipal building load failed to meet that 10,000 kW threshold is expressly disqualified from participation under Illinois law. By its very terms, the IGCA does not act to change the character of the applicant customer, whether that customer meets express statutory requirements, and whether its separately obtained REC delivery contract qualifies for bill credits. IPA Resp. at 19.

4. Commission Analysis and Conclusion

The Commission notes that the relevant part of the statute provides the following definitions:

“Eligible self-direct customer” means any retail customers of an electric utility that serves 3,000,000 or more retail customers in the State and whose total highest 30-minute demand was more than 10,000 kilowatts, or any retail customers of an electric utility that serves less than 3,000,000 retail customers but more than 500,000 retail customers in the State and whose total highest 15-minute demand was more than 10,000 kilowatts.

“Retail customer” has the meaning set forth in Section 16-102 of the Public Utilities Act and multiple retail customer accounts under the same corporate parent may aggregate their account demands to meet the 10,000 kilowatt threshold. The criteria for determining whether this subparagraph is applicable to a retail customer shall be based on the 12 consecutive billing periods prior to the start of the year in which the application is filed.

20 ILCS 3855/1-75(c)(1)(R)(1). The Commission agrees with NRG Companies regarding different utility territories. The IPA asserts that the “or” in the definition of eligible self-direct customers requires that customers must be either one or the other. The Commission notes that the “or” is not carried through to the provision allowing for aggregation of demands and no distinction is made between utility territories. And, as Staff notes, the statute contains no language limiting this “single corporate parent” provision to a single utility service territory. The Commission finds that the LTRRPP should be modified to reflect the ability of customers under the same corporate parent to aggregate their account demands to meet the 10,000 kW threshold and that customers must qualify their accounts according to the statutory definition of “Eligible self-direct customer” for each of the utilities in which the customer has accounts that it seeks to aggregate to meet the 10,000 kW threshold. Further, the Commission finds that the LTRRPP should be modified to specify that customer accounts may only receive the Self-Direct Program credit that is specific to the utility that serves that account.

With respect to municipalities aggregating their demand, the Commission does not adopt the proposal of NRG Companies. Municipalities that have entered into an intergovernmental agreement are not “under the same single corporate parent” as required by the IPA Act. Moreover, the Self-Direct Program does not allow an eligible customer to acquire or retire RECs on behalf of another customer, or to reduce another customer's RPS charges. Thus, this is not a power that can be shared pursuant to the IGCA.

B. Section 6.5 Self-Direct Crediting and Accounting/Section 6.5.1 Self-Direct Bill Crediting

1. City's Position

The City asks the Commission to ensure that the methodology in the LTRRPP for calculating the Self-Direct Bill Credit properly reflects the General Assembly's intent in P.A. 102-0662 to make the Self-Direct Bill Credit a more effective incentive to spur utility-scale renewable projects, while also not negatively impacting the available budget for the IPA's Illinois Solar for All (“ILSFA”) and ABP. The City's grounding principle on this issue is the importance of supporting those programs, which align with the City's own policies in its Climate Action Plan and will lead to greater availability of distributed energy resources, community solar and community-owned solar, and other benefits to low-income City residents. However, the IPA's methodology would provide a credit against the monthly RPS charge of only perhaps 10% of the charge, leaving a customer to continue paying the remainder of the tariff. The City is concerned that, with such a small increment of the total credit, entities, especially public sector entities like the City, that would otherwise be inclined to meet the REC procurement target would lack the financial incentive, or would even be disincentivized, from doing so. City Obj. at 2-3

In addition, the City argues that greater participation in the Self-Direct Program means Illinois will get closer to its RPS goal, which Illinois is presently far behind. While the statutory goal for the Illinois RPS in the 2022-2023 delivery year is 20.5%, current projections identify a compliance rate of only 7.3%. See LTRRPP, App. B2. Broader participation in the Self-Direct Program will accelerate progress towards meeting (and perhaps exceeding) the escalating RPS goals set by the legislature. City Rep. at 2.

The City states that it supports certain proposed modifications to the Self-Direct Program and proposes its own modifications. The City recommends: 1) a prorated approach to the delivery quantity requirement that will provide a fair valuation among customers, is consistent with the law, and will provide certainty to customers; and 2) an alternative approach for establishing the Self-Direct Bill Credit so that program participants receive credit values commensurate with the proportion of RECs secured compared to load. City Rep. at 2.

While not explicitly noted in the LTRRPP, the Self-Direct Program has three aspects that inform the City's position. First, RECs delivered through the Self-Direct Program are of equal value to RECs secured through the standard IPA process; therefore, RECs secured by the IPA and those secured by qualified customers are of equal value in meeting Illinois' RPS goals. Transparent rules and processes for the Self-Direct Program are just as important as transparency in all other RPS-related activities. City Rep. at 3.

Second, with regard to RPS funding, because a customer's utility-scale purchases count the same as those secured by the standard IPA process in meeting the state's RPS goals, the money apportioned to credits should not be viewed as diminishing resources to meet RPS goals but, instead, as an alternative pathway to contribute to the states' RPS goals. City Rep. at 3.

The City notes that the Joint NGOs do not support ComEd's alternative methodology for establishing credit value in the Self-Direct Program due to concerns that higher credit valuation would lead to difficulties in maintaining the RPS budget. However, the City maintains that the Joint NGOs do not clearly identify how a generally higher level of credit valuation would negatively impact other RPS programmatic goals. City Rep. at 6.

The City recommends the prorated approach because it provides for a fair valuation among customers. The application of a single credit value for all customers in the Self-Direct Program, regardless of the portion of their consumption being offset by their REC contracts, would cause unequal compensation between customers. The singular valuation approach proposed by the IPA has the potential to deliver a varying level of value to different customers. This result appears to be contrary to the IPA Act. See 20 ILCS 3855/1-75 (c)(1)(R)(4). The City notes that the statute requires the credit received by participants to equate to the cost of utility scale RECs secured through the IPA procurement process. Additionally, because participants may secure different proportions of RECs relative to their load, these differences in proportion can yield differing rates of compensation for RECs provided by participants. Therefore, the City recommends that the Commission find that the Plan be amended to include a prorated valuation approach for credits to ensure that the Commission achieves and maintains compliance with the statute's requirements while properly incentivizes customers to maximize their renewable usage. City Rep. at 4-5.

The City's approach is consistent with ComEd's and NRG Companies' justifications for ComEd's alternative to calculate the Self-Direct Program bill credit. City Rep. at 6.

The IPA dismisses ComEd's proposal as inconsistent with the statute and claims its LTRRPP provides the only method of valuing credits (i.e., a single percentage reduction in RPS charges). The City asserts that the IPA fails to provide important details about:

- i. The mechanics of the credit calculation;
- ii. How IPA's single value credit approach complies with statutory requirements that volumetric charges be "equivalent to the anticipated cost of renewable energy credit deliveries under contracts for new utility-scale wind and new utility-scale solar entered for each delivery year after the large energy customer begins retiring eligible new utility scale renewable energy credits for self-compliance." See 20 ILCS 3855/1-75 (c)(1)(R)(4); and
- iii. Whether and to what extent IPA's hold back of hundreds of millions of dollars in RPS funds annually could mitigate real or imagined funding

impacts on ABP, ILSFA, or other utility-scale REC purchases. Notably, IPA can use money in any year because it is fungible.

Given the instability of RPS funding in past years, the lack of details concerning these core financial issues should weigh heavily on all market participants regardless of their positions on the Self-Direct Program. Indeed, this lack of transparency is likely to cause confusion in the market and thereby reduce consumer participation in the Self-Direct Program. City Rep. at 7.

Accordingly, the City recommends a model that establishes a fair value for credits through the Self-Direct Program that meets statutory requirements. See Declaration of Mark Pruitt, ¶¶ 5-6. Under the City's proposed approach:

- i. Credits equal the anticipated cost of renewable energy credit deliveries under contracts for new utility-scale wind and new utility-scale solar in future years as secured through the standard IPA procurement process;
- ii. Credits must not be factored by the costs of other programs or prior purchases; and
- iii. The Self-Direct Bill Credit must be expressed as a reduction in the monthly RPS charges the customer pays to its utility.

In addition to regulatory compliance, this approach addresses concerns presented by other parties regarding potential impacts on other RPS budgets by providing the IPA with a definitive tool to accurately estimate the budgetary impact of the Self-Direct Program on total RPS budgets. City Rep. at 7-8.

The City also proposes capping the Self-Direct Program bill credit so that it cannot impact ABP, ILSFA, or other utility-scale REC purchases. City Rep. at 8.

2. NRG Companies' Position

NRG Companies note that the structure of the Self-Direct Program proposed by the IPA would improperly limit the availability of the program and the value of the credit to participating customers and would disincentivize customers from procuring additional renewable energy credits under the program beyond the 40% floor that is established by P.A. 102-0662. NRG Companies encourage the Commission to consider the following guiding principles as it evaluates the IPA's proposed Self-Direct Program: competitiveness; certainty; simplicity; and future proofing. NRG Obj. at 3.

NRG Companies point out that it is important that the Commission recognize the way in which the Self-Direct Program is to be funded. The IPA claims that because the "qualifying self-direct customer pays reduced volumetric RPS charges, the overall RPS budget is reduced accordingly based on qualifying self-direct customer participation, and less funds are available for all RPS program and procurement activities." IPA Pet. at 32. However, this reduction in budget is met with an equal reduction in RPS targets, which the IPA fails to acknowledge. NRG Companies explain that the Self-Direct Program will simply swap out utility-scale RECs that are procured by the IPA with those procured by self-direct participants. NRG Companies argue that the Self-Direct Program is just a more efficient way to procure those utility-scale RECs, under terms that incentivize additional new renewable development in Illinois. NRG Companies state that the IPA is projecting

that it will “hold back” a substantial amount of funds each year, beginning with more than \$400 million next year and escalating to more than \$5 billion annually in future years. Unlike the other IPA procurement programs, there is no “hold back” of the funds used by self-direct participants. NRG Resp. at 5.

According to NRG Companies, the IPA fails to acknowledge the benefits that customers receive because of the Self-Direct Program, including:

1. Lower volumes of customer-funded REC purchases from utility-scale wind and solar resources (i.e., ongoing cost savings for consumers);
2. More rapid deployment of new capacity and generation resources to contain rising energy costs (i.e., more ongoing cost savings);
3. More rapid deployment of renewable resources in Illinois (i.e., accelerated receipt of environmental benefits); and
4. More development and job growth opportunities (i.e., general economic growth for all).

NRG Companies state that the IPA’s statements also fail to acknowledge the simple fact that Self-Direct Program participants will meet at least 40% of their load with RECs from new eligible renewable energy resources. The IPA projects the level of REC offsets for the 2022-2023 delivery year to be only 7.5% (even though the annual goal is 20.5%) and is projected (though not guaranteed) to reach the 40% level by delivery year 2030-2031. Given this, for several years, a Self-Direct Program participant who participates even at the minimum 40% level is guaranteed to produce more RECs to satisfy the Illinois RPS than a non-Self-Direct Program participant. NRG Rep. at 2-3.

Further, NRG Companies argue that the IPA’s assertions ring hollow when one considers the significant level of unexpended RPS funds the IPA plans to maintain on an annual basis. The end-of-year Balance is roughly equal to or exceeds the RPS total annual spending on an annual basis as referenced in the LTRRPP. See LTTRRP, App. B2, tab ‘RPS Spend Model’. The end-of-year balance in RPS equates to 95.5% of total annual RPS-related spending in delivery year 2022-2023 and generally grows over time to exceed total annual RPS-related spending by the 2025-26 delivery years. See LTRRPP, App. B2, ‘RPS Spend Model’. NRG Rep. at 3-4.

Based on this analysis, NRG Companies conclude that a successful Self-Direct Program clearly does not present a substantial risk to funding for the ABP, ILSFA, training programs, or even the IPA’s substantial administrative overhead (which exceeds \$11 million per year). See LTTRRP, App. B2, tab ‘RPS Spend Model,’ Column F. Arguably, the primary limiter to funds flowing to these other RPS programs is the IPA itself through its plans to withhold hundreds of millions of dollars from use in fulfilling (or exceeding) the state’s RPS goals. NRG Rep. at 4-5.

NRG Companies encourage the Commission to ignore the IPA’s misleading statements concerning the potential funding impact that the Self-Direct Program on other RPS-related programs. NRG Rep. at 5.

NRG Companies state that the Commission should recognize that for purposes of the State meeting its RPS goals, utility-scale RECs delivered through the Self-Direct

Program are of equal value to those procured through the standard IPA procurement process. Accordingly, NRG Companies aver that the IPA should provide the same level of details and transparency regarding the rules and processes for the Self-Direct Program as it provides to other RPS-related activities. This has not been the case, however. For example, the IPA has provided only a vague reference to Self-Direct Program credits being worth 10% of RPS fees and not presented any calculations to support this estimate. This lack of transparency is likely to cause confusion in the market and cause eligible customers to avoid the program due to an elevated perception of risk. A low participation level in the Self-Direct Program reduces potential environmental and economic advances within Illinois. The General Assembly clearly found it important to engage large energy users to help the State meet its RPS goals; the IPA should not be allowed to undermine the Self-Direct Program due to a misguided view that it somehow competes with the IPA's budget. NRG Rep. at 6.

Moreover, NRG Companies state the value of credits for Self-Direct Program participants needs to account for the difference in the scale of compliance between customers who simply support the standard RPS program and those who participate in the Self-Direct Program. The IPA maintains that the credit valuation approach in its proposed LTRRPP, which only considers the total cost of utility-scale RECs relative to all RPS expenditures in that same delivery year, is the only interpretation of the statute. According to NRG Companies, this simplistic approach yields an artificially low value for the credit as it does not consider the fact that Self-Direct Program participants will be significantly over-delivering RECs to the Illinois RPS relative to customers who do not participate in the Self-Direct Program. NRG Companies note that the IPA projects the level of RPS compliance for the 2022-2023 delivery year to be only 7.5% and projects (though it does not guarantee) reaching the 40% level by delivery year 2030-2031 (see LTRRPP Appendix B2, tab 'REC Delivery Model') while the Self-Direct participants are contractually required to procure RECs equal to at least 40% of their usage for the entire term of their contracts. See 20 ILCS 3855/1-75(c)(1)(R)(2)(iv). Viewed in this light, NRG Companies claim the IPA's proposal for credit valuation would undercompensate Self-Direct Program participants because it does not factor on the higher overall volume of RECs the Self-Direct Program participants are providing for the RPS. The Commission should recognize the volumetric benefits provided by the Self-Direct Program and require a crediting approach that factors in the much higher level of RECs delivered through the Self-Direct Program to a credit level. NRG Rep. at 6-7.

In addition, the statute contemplates that the Self-Direct Program participants will receive a credit that varies based upon the volume of RECs procured. See 20 ILCS 3855/1-75(c)(1)(R)(4). The NRG Companies interpret the statute as requiring the Commission to approve a credit that considers the cost of RECs (\$/REC), since this allows for the application of credits that reflect the proportion of RECs the Self-Direct Program participant would purchase in relation to its annual load. The IPA interprets the statute to provide for a single credit value that is to be applied for all Self-Direct Program participants regardless of the volume of RECs those participants secure. NRG Rep. at 7-8.

The IPA proposal would provide a higher level of compensation on a per-REC basis to a Self-Direct Program participant that secures RECs equal to only 40% of its load

than a participant that secures RECs equal to 100% of its load. For example, assume that the IPA recommended a \$0.00051/kilowatt-hour (“kWh”) reduction in the monthly RPS charge for all Self-Direct Program participants in a delivery year (approximately 10% of the current RPS charge for ComEd customer). A Self-Direct Program participant with annual consumption of 50,000,000 kWh of electricity would realize credits worth \$25,400 if it secured RECs equal to at least 40% of its consumption from qualified resources. If the Self-Direct Program participant purchased 20,000 RECs (40% of annual consumption), then the credit would be worth \$1.27/REC (\$25,400 divided by 20,000 RECs). However, if that Self-Direct Program participant purchased 50,000 RECs (100% of annual consumption), then the credit would be worth \$0.508/REC (\$25,400 divided by 50,000 RECs). The NRG Companies make two observations regarding the results of the IPA approach to credit valuation: (1) the level of credit is nowhere near the rate secured for utility-scale RECs through the IPA procurement process; and (2) the Self-Direct Program participant is incentivized to minimize – not maximize – the level of participation by Self-Direct Program participants. Neither result seems consistent with the intent of the statute. NRG Rep. at 8.

NRG Companies note that the IPA’s position is that a new credit value would be applied in each year for Self-Direct Program participants, and that the credit value would reflect the category of changing costs in each reference year. Thus, every year’s purchase of new utility-scale wind and solar RECs will yield a different Self-Direct Program credit value that will impact new and existing contracts of all self-direct customers. NRG Rep. at 9.

The NRG Companies explain that Section 1-75(c)(1)(R)(4) should be interpreted to require the IPA to annually submit a calculation of the credit value that applies for the entire length of new contracts of new and existing self-direct customers. In addition to providing a level of certainty for Self-Direct Program participants, extending the initial reference year credit value to the entire term of the participants’ REC contracts would provide the IPA with a more predictable level of cost impact resulting from the Self-Program as REC volumes would be delivered at a known value over the long term. NRG Rep. at 9-10.

The IPA’s simplistic interpretation of the statute may work in theory, but NRG Companies explain that it fails to address the implications of several scenarios that have occurred in the IPA’s recent history:

- The IPA does not procure RECs from utility-scale wind and solar resources in a given reference year: Utility Scale Wind (2019, 2021), Non-Photovoltaic Community;
- Renewable Generation (2019), Brownfield Solar (2018); and
- The IPA proposes to administratively reduce REC compensation for providers of RECs from utility-scale wind and solar resources (2021).

NRG Companies note that the IPA provides no analysis for how its plan for annually changing credit values squares with the practicalities of these historical events. NRG Rep. at 10.

Instead of resetting the value of all billing credits for the Self-Direct Program each year, the IPA should adopt an approach that would provide a Self-Direct Program participant with a fixed per kWh bill credit value that would extend through the entirety of the participant's REC contract. NRG Obj. at 7.

NRG Companies note under ComEd's alternative methodology, in cases when a self-direct participant matches 100% of their annual consumption with RECs from a qualified renewable resource that receiving all or almost 100% of the RPS charge is fair and complies with state statute. NRG Companies offer two recommendations to improve upon ComEd's proposed methodology for determining the Self-Direct Rebate credit, both of which are designed to encourage additional participation in the Self-Direct Program. In cases when the self-direct participant is offsetting less than 100% of annual consumption, then the value of utility-scale RECs secured through the standard IPA procurement process should be prorated to the level of offset consumption. NRG Companies assert that ComEd's proposal also should be modified to set the Self-Direct Program credit value annually, allowing all self-direct eligible customers selected in each year to receive that Self-Direct Program credit value for the entire term of their self-direct purchase agreements. NRG Resp. at 3-4.

With these two recommendations, the NRG Companies support the inclusion of ComEd's proposed methodology for establishing the value of the Self-Direct Program credit. NRG Resp. at 4.

3. ComEd's Position

ComEd shares the IPA's objective of designing a Self-Direct Program that – unlike the State's prior RPS self-direct initiative – effectively spurs the development of new renewable projects. The Plan's methodology for calculating the self-direct bill credit, ComEd maintains, will almost certainly chill participation in the Self-Direct Program and thus discourage the development of the new wind and solar renewable projects that the Self-Direct Program was designed to incent. Consistent with the proposed methodology and bill crediting example set forth in the Plan, ComEd estimates that a participating customer's credit would reduce the customer's monthly RPS charge by only 10% (i.e., \$0.50/megawatt-hour ("MWh") or \$0.0005/kWh) even though the customer is required to procure RECs from new wind or new solar projects for 40% of its load – which is the State's RPS REC target for delivery year 2030 applicable to all load delivered by electric utilities subject to the RPS. See 20 ILCS 3855/1-75(c)(1). Put another way, a participating customer would receive only a 10% discount off its monthly RPS charge in exchange for accelerating – by eight years – achievement of the State's 2030 REC procurement goal with respect to the customer's load. ComEd Obj. at 4.

ComEd notes Illinois law previously included a version of an RPS Self-Direct Program where alternative retail electric suppliers ("ARES") were responsible for complying with the RPS targets applicable to the retail customers they supplied. Because of its "short-term, transactional incentive structure for ARES self-directed RPS compliance," "very little new renewable generation was able to be developed through this compliance mechanism." LTRRPP at 129; ComEd Obj. at 5.

ComEd says that it is not plausible that the economics of the General Assembly's new Self-Direct Program would so dramatically discourage – if not effectively penalize –

participation. Indeed, it is unclear to ComEd why a customer would agree to terms requiring accelerated achievement of the 2030 RPS goal while continuing to pay nearly all (90%) of the monthly RPS charge. That the State is currently falling well short of the existing RPS goals only further exacerbates the unfairness of holding Self-Direct Program participants to such a high standard in exchange for de minimis compensation. ComEd Obj. at 4-5.

ComEd proposes an alternative self-direct bill crediting methodology that better reflects the value of a Self-Direct Program customer's participation and contribution, and which results in a cents-per-kWh credit that approaches the customer's monthly RPS cents-per-kWh charge. Like the IPA, ComEd has devoted considerable time to analyzing the bill crediting provisions of P.A. 102-0662 to develop the best path forward for incentivizing participation and, ultimately, the energization of new wind and solar projects. As with the LTRRPP, ComEd began with the statutory language in Section 1-75(c)(1)(R)(4) of the IPA Act. See 20 ILCS 3855/1-75(c)(1)(R)(4); ComEd Obj. at 7-8.

From this language, ComEd gleans the following principles. In the first sentence, ComEd understands that the credit should be applied against the monthly cents-per-kWh RPS charge that ComEd assesses under its RPS rider, Rider REA - Renewable Energy Adjustment ("Rider REA"), which recovers ComEd's RPS costs, and further, that this credit should be equal to the costs of REC deliveries associated with contracts for new utility-scale wind and solar RECs entered into for delivery years after the customer commences participation in the Self-Direct Program. As to the second sentence, the credit amount must be determined annually, and must equal the portion of the cost authorized by the RPS rate cap that supported the annual procurement of utility-scale RECs using a methodology described in the LTRRPP, expressed on a per kWh basis, provided that the bill credit exclude amounts associated with delivery years preceding the customer's Self-Direct Program participation and those amounts related to procuring RECs under the ABP and other authorized programs. While certain of the language in Section 1-75(c)(1)(R)(4) is undoubtedly challenging, ComEd states these instances of vagueness or ambiguity also create opportunities to faithfully interpret these provisions and give full effect to the General Assembly's intent. Indeed, it is notable that the law grants the IPA the authority to develop a "methodology" rather than merely perform a rote statutory calculation. ComEd Obj. at 8.

Consistent with the statute's bill crediting framework, ComEd recommends that the Plan be revised to incorporate an alternate bill crediting methodology that fairly compensates Self-Direct Program participants for the RECs they procure, which will ensure the Self-Direct Program is poised for success and stands the best chance of realizing the General Assembly's intent to incentivize new renewable projects. First, to give effect to the requirement that the Rider REA credit equals REC deliveries under contracts for new wind and new solar, ComEd proposes that the credit value equal the average cost of a REC procured from a utility-scale new wind or new solar project. As to the results of the calendar year 2018 procurements, this average cost was \$4.95 per REC, and since 2017 this average cost is \$4.77 per REC. Second, with respect to the law's directive that the IPA develop a methodology to value the RECs from utility-scale new wind and solar projects that are supported by the Rider REA charge, ComEd contends that a methodology that utilizes the actual utility-scale values does just that.

Moreover, because this methodology excludes any other costs associated with pre-existing contracts or with the ABP and other approved programs, it gives effect to the required exclusions. ComEd Obj. at 8-9.

This alternate methodology, ComEd claims, resolves one of the principal “contradictory elements” identified by the Plan in Section 1-75(c)(1)(R)(4), namely the reference to valuing anticipated REC values in one sentence and the subsequent reference to valuing past REC values in the second sentence. Because RECs from utility-scale new wind and solar contracts are subject to multi-year contracts whose costs are recovered over multi-year periods, ComEd recommends that the multi-year value of \$4.77 be used as a proxy for the value of the utility-scale new wind and solar RECs procured by Self-Direct Program participants, which is inclusive of both past REC costs and those anticipated in the future. Indeed, in a very real and practical sense, each utility-scale REC procured by a Self-Direct Program participant is one less REC that electric utilities must procure under an IPA-led procurement. ComEd Obj. at 9.

ComEd points out that it is important to account for the fact that many companies are interested in the Self-Direct Program – not because it is necessarily less expensive to acquire RECs on their own outside of the IPA’s RPS programs – but because these companies have their own environmental, social, and governance goals requiring that they purchase and retire RECs (on their own) to achieve these goals. In fact, many companies have adopted environmental, social, and governance goals that go beyond the State’s ultimate 40% renewable target. Implementing the Self-Direct Program in a way that does not discourage or impede these actions and behaviors will not only help the State meet its RPS goal more quickly but could propel the State to a level of renewables achievement that surpasses the 40% target. ComEd Obj. at 10.

ComEd notes that the crux of the IPA’s opposition to ComEd’s methodology appears to be based on a fear that the RPS will be diminished – rather than strengthened – by a robust Self-Direct Program. The IPA claims that because the “qualifying self-direct customer pays reduced volumetric RPS charges, the overall RPS budget is reduced accordingly based on qualifying self-direct customer participation, and less funds are available for all RPS program and procurement activities.” IPA Pet. at 32. However, this reduction in budget is met with a concomitant reduction in RPS targets, which ComEd claims the IPA fails to acknowledge. To be sure, P.A. 102-0662 mandates this reduction. See 20 ILCS 3855/1-75(c)(1)(R)(3). ComEd Obj. at 11.

To put a finer point on the matter, ComEd points out that the statute requires that over 70% of the RECs procured to meet the State’s objectives need to be sourced from utility-scale wind and solar projects. ComEd estimates that if every ComEd customer eligible for the Self-Direct Program participated (i.e., customers who have or can aggregate to 10 megawatts (“MW”) or more of demand), then they would provide 6,000,000 to 15,000,000 (depending on the level of participation – 40% up to 100%) of the required approximate 22,000,000 utility-scale RECs that must be purchased anyway. Providing a near-full credit against the RPS charge for Self-Direct Program participants simply means that the majority of funds collected from other non-participant customers will be able to be dedicated to the ABP and ILSFA (instead of limiting those dollars) while also ensuring that Self-Direct Program customers are recognized and not penalized for their contributions in helping the State meet its renewable goals. ComEd Obj. at 11-12.

In response to parties' claims that ComEd's proposal runs afoul of the statute, ComEd states that its proposal fully honors the required statutory exclusions. For example, the IPA repeatedly quotes from the second sentence of Section 1-75(c)(1)(R)(4), which states, inter alia, that the bill credit amount cannot include "costs associated with procuring [RECs] through existing and future contracts through the [ABP], subsection (c-5) of this Section 1-75, and [ILSFA]." IPA Resp. at 22, 31; see also JSP Resp. at 11-12. However, ComEd's alternative methodology expressly does not include these costs, and in fact does not address these costs at all. Consistent with the statute, ComEd avers that its methodology focuses on setting a credit value that is based on, and limited to, average market-based prices for new utility-scale RECs. ComEd Rep. at 13.

Moreover, there is no risk that the Self-Direct Program could result in over-procuring utility-scale RECs to the detriment of funding other RPS programs like the ABP and ILSFA. If all identified eligible ComEd customers participated in the Self-Direct Program and entered into contracts for 100% of their consumption, it would still only result in approximately 70% of the utility-scale RECs required to be procured for ComEd deliveries. ComEd Rep. at 13-14.

ComEd appreciates NRG Companies' support for the proposed alternative methodology, and ComEd also supports NRG Companies' companion proposal clarifying that the bill credit be fixed upfront and extend for the duration of the participant's REC contract. Anything less would lack the transparency and certainty required by customers who are contemplating whether or not to participate in the Self-Direct Program. ComEd Resp. at 5-6.

NRG Companies propose that the bill credit a customer receives under the Self-Direct Program should increase as the customer procures more RECs. This interpretive issue should be resolved in a way that gives effect to the General Assembly's intent and fulfills the purposes of the Self-Direct Program. ComEd Rep. at 4.

Because NRG Companies and ComEd understand the 40% REC procurement requirement to be a minimum, ComEd appreciates that its alternative methodology could benefit from clarification and further detail regarding how the bill credit will apply depending upon the amount of RECs procured. As ComEd understands NRG Companies' proposal on this issue, NRG would adjust the value of the per-REC credit depending upon the amount of load covered by RECs procured under the program. That per-REC credit amount would then be applied against and reduce the RPS charge, which would then be applied to the participant's entire load. For example, assuming the Self-Direct Program credit value was \$4.77 and the participant procured RECs to cover 40% of its load, the credit would be \$1.908 ($\$4.77 \times 40\%$). Subtracting \$1.908 from the RPS charge of \$5.02 reduces the overall charge to \$3.112. If the participant's total load were 100 MWhs, then the participant's total bill charge would be \$311.20 ($100 \times \3.112). ComEd Rep. at 11.

While ComEd recommends a slightly different calculation that more directly ties the Self-Direct Program credit to the RECs procured under the Self-Direct Program, both approaches ultimately reach the same value of the credit on the customer's bill. Under ComEd's proposal, each MWh of the participant's load that is covered by a REC procured under the Self-Direct Program would receive the full credit value of \$4.77, and the portion

of the participant's load not covered by such RECs would still be subject to the usual RPS charge of \$5.02. ComEd believes that this calculation best reflects the operation of the Self-Direct Program and the General Assembly's intent to provide the Self-Direct Program credit for the RECs procured, and thus recommends its approval. ComEd Rep. at 11.

With respect to annual calculation of the credit, ComEd notes that the IPA continues to contend that the bill credit's annual calculation requires that all REC contracts under the Self-Direct Program be subject to the new (and fluctuating) value approved each year. ComEd, however, shares NRG Companies' and Staff's interpretation that "[t]he credit amount [] is locked in with respect to any projects entered into during each year." Staff Resp. at 8. The IPA's proposal to annually reach back and apply the updated credit value to all previously executed contracts introduces an unnecessary and unacceptable level of uncertainty and volatility for Self-Direct Program participants. Indeed, the absence of a fixed value for a given contract's term is inconsistent with other contracting arrangements under the RPS. ComEd Rep. at 11.

In sum, the Commission is presented with two very different choices regarding implementation of the Self-Direct Program. ComEd encourages the Commission to adopt its alternative methodology, which aligns with and leverages the environmental, social, and governance and other goals of the State's largest energy users by transparently and fairly valuing the RECs procured under the Self-Direct Program. An optimized Self-Direct Program will serve a vital role in stimulating these sophisticated energy users to actively participate in and advance the clean energy transition in partnership with the State. ComEd Rep. at 15.

4. Joint Solar Parties' Position

The IPA took a new statute creating a new Self-Direct Program and made reasonable interpretations of convoluted statutory language. Several parties, including NRG, ComEd, and the City desire higher pricing for self-direct credits and objected to the IPA's interpretations. The Joint Solar Parties recommend that the Commission reject the proposed changes to the IPA's well-reasoned interpretation. JSP Resp. at 10.

The JSPs explain that the IPA interpreted Section 1-75(c)(1)(R) as providing a credit equal to the portion of the RPS charge attributable to the estimated actual payments to the utility-scale systems procured in delivery years on or after a customer's admission to the Self-Direct Program. The Joint Solar Parties note that this interpretation gives effect to the entire statutory section, including the express prohibition on including costs related to prior utility-scale procurements and any ABP or ILSFA costs. JSP Resp. at 11.

After acknowledging that the IPA's interpretation addressed the statutory language, ComEd abandons the plain language and proposes a credit based on average REC price. While it may seem on the surface to be the same or at least similar, ComEd proposes a completely different framework. The Joint Solar Parties explain that the statute requires a credit based on the estimate of the actual REC payment's effect on the RPS charge. The RPS charge is capped by statute (20 ILCS 3855/1-75(c)(1)(E)), which amounts to about 0.50248 c/kWh in ComEd's service area. In other words, the credit is a portion of 0.50248 c/kWh, and will be higher or lower depending on the proportion of estimated actual spend on qualifying RECs (i.e. those procured on or after the date the

self-direct customer joins the program) to other RPS charges, as will be determined by the IPA's methodology. JSP Resp. at 11-12.

ComEd's "alternative proposal" for compensation of \$4.77/REC to self-direct customers has the effect of invalidating the statutory language that the portion of RPS charges related to the ABP, ILSFA program, and previous utility-scale procurements cannot be subject to the credit. The JSPs aver that ComEd's interpretation is thus inconsistent with the enabling statute and thus should be rejected. JSP Resp. at 12.

The JSPs note that NRG Companies support ComEd's proposal but do not account for the conflict between the structure of ComEd's proposal as a REC price-based credit compared to the statutory language requiring the credit take into account the relative impact of the qualifying RECs on the total RPS charge. JSP Resp. at 12.

ComEd, NRG Companies, and the City all complain that the credit value is too low, with both ComEd and the City citing that the credit will be 10% or less of the RPS charge. Respectfully, the JSPs aver that the issue is with the General Assembly who explicitly and unambiguously limited the self-direct credit to the proportion of impact of eligible RECs on the overall RPS charge. JSP Resp. at 12-13.

The Joint Solar Parties note that ComEd and NRG Companies also appear to make policy arguments about the value of the Self-Direct Program to meeting new renewable development goals. While the JSPs of course support expanded and additional new renewable development, ComEd and NRG Companies appear to misapprehend the policy behind P.A. 102-0662. Under P.A. 99-0906, the General Assembly transitioned Illinois away from an RPS focused on "top-line percentages" and toward procurement targets from new generation. The General Assembly carefully crafted allocations of those obligations between wind and solar, and utility-scale and distributed systems. P.A. 102-0662 reinforced those obligations, once again allocating specific new development targets to specific subsets of systems. See, e.g., 20 ILCS 3855/1-75(c)(1)(C)(ii). Notably, the focus of the LTRRPP is on meeting those new development goals for each specific subset of systems in Section 1-75(c)(1)(C)(ii) but only "shall attempt to meet" the top-line percentage goals in 1-75(c)(1)(B). JSP Resp. at 13.

Staff supports ComEd's proposal, but it appears to the JSPs that Staff - like ComEd, the City, and NRG Companies - did not account for the clear and explicit statutory language excluding certain costs from the Self-Direct Program bill credit. Staff's reasoning reads out the entire exclusion - something the Commission clearly cannot do based on the precedent cited by Staff - and focuses only on the top-line analysis of what the credit may be. Similarly, Staff's proposal is lacking because it does not have a step that excludes the "existing and future" costs of ILSFA, ABP, and the coal-to-solar program. Because it does not comply with the explicit directive of statute, Staff's proposal must similarly be rejected. JSP Rep. at 37.

5. CGA's Position

CGA notes that NRG Companies argue that the Self-Direct Program should not impact the RPS budget for non-utility-scale REC programs. CGA asserts that NRG Companies' position is a tautology not supported by the law. The statute that establishes

the Self-Direct Program RPS compliance only states that the credit amount is based on the estimated cost of utility-scale RECs in the prior delivery year. It does not state that funding for utility-scale RECs would be reduced. 20 ILCS 3855/1-75(c)(1)(R)(4). CGA Rep. at 2-3.

CGA explains that in the absence of a direct statement that the utility-scale REC fund is to be reduced, the assumption is that the cost of Self-Direct Program RECs is generally applied to the RPS Fund in aggregate, like other REC products. Moreover, there is only the RPS Fund, there is no defined account or dollars set aside within the RPS Fund for utility-scale RECs, from which funds are to be withdrawn or is to be reduced. Finally, NRG Companies' proposal increases the uncertainty around utility-scale RECs. It creates one more cap on money available to utility-scale REC contracts that could cause a premature pause in utility-scale REC procurements. This risk impacts the ability to finance a project. Based on the foregoing, the Commission should deny NRG Companies' proposal and find that the money used to pay Self-Direct Program RECs comes from the RPS Fund in aggregate. CGA Rep. at 3.

6. Joint NGOs' Position

The Joint NGOs note that P.A. 102-0662 requires the IPA to "establish a self-direct renewable portfolio standard compliance program for eligible self-direct customers that purchase renewable energy credits from utility-scale wind and solar projects through long-term agreements." 20 ILCS 3855/1-75(c)(1)(R). As the IPA indicates in the Plan, the Self-Direct Program is intended to "support the spirit informing the Illinois RPS," that is, "new renewable energy projects sited in areas that bring benefits back to Illinois residents and businesses." 20 ILCS 3855/1-75(c)(1)(R)(2). In particular, the Joint NGOs state it should comport with and support the labor and diversity, equity, and inclusion requirements laid out in P.A. 102-0662. 20 ILCS 3855/1-75(c)(1)(R)(2)(vii). The IPA also acknowledges that, in crediting against participating customers' RPS bill charges, the Self-Direct Program will result in a reduction of available RPS budgets, but that the program should also reduce required REC procurement quantities and associated costs. The IPA understands the underlying statute to mean that the Self-Direct Program's bill crediting methodology cannot reduce a given year's RPS budget allocated for the ABP and the ILSFA program. JNGO Resp. at 3-4.

The Joint NGOs support recognizing these overarching goals for the Self-Direct Program, namely: (1) it should ensure high-quality RECs from new renewable energy projects and (2) it should maintain the RPS budget for the ABP and ILSFA program. These two foundational principles guide the Joint NGOs' proposals for the Self-Direct Program. JNGO Resp. at 4.

The Joint NGOs note that ComEd appears primarily focused on adopting a proposal that stimulates new, utility-scale renewable development. ComEd dismisses the concern regarding the reduction in the RPS budget that would result from greater reductions in participating customers' RPS charges, arguing that this reduction in budget is met with a concomitant reduction in RPS targets. This is not the simple one-for-one exchange that ComEd implies, however. The RPS budget funds the ABP and ILSFA program, which support critical state policy goals such as smaller-scale renewable energy development, equity in renewable energy access, and energy sovereignty. Although the

Self-Direct Program reduces REC procurement targets, the IPA will nonetheless have to obtain a significant portion of the remaining RECs through the ABP and ILSFA, and there must be sufficient funds for those programs to be successful. JNGO Resp. at 5.

The Joint NGOs agree with ComEd (and the IPA) that a core goal of the Self-Direct Program is to promote new renewable energy development. The Joint NGOs also agree with the IPA that this goal must be considered in tandem with the need to maintain the RPS budget for the ABP and ILSFA. The Joint NGOs believe the IPA appropriately balances these two goals in its proposed bill crediting methodology. The Joint NGOs do not support ComEd's objection and alternative methodology, as they appear to dismiss the important concern related to maintaining the RPS budget. JNGO Resp. at 5-6.

NRG Companies express concern that the Plan incentivizes Self-Direct Program participants to procure only 40% of their energy supply from eligible renewable energy projects and instead should incentivize participants to procure up to 100% of their energy supply from such projects. The Joint NGOs encourage the Commission to balance, on one hand, encouraging participants to procure more eligible RECs above the 40% threshold, with the undesirable reductions in the RPS budget for the ABP and ILSFA. The Joint NGOs believe that the IPA appropriately balances these two concerns in its own proposal. The Joint NGOs do not support NRG Companies' proposal, which does not address the importance of maintaining the RPS budget. JNGO Resp. at 6-7.

The Joint NGOs agree with the IPA that not all RECs are created (or priced) equally, and that the Self-Direct Program is intended to credit only RECs from additive utility-scale projects, in a like-for-like exchange. The Joint NGOs disagree with Staff that the statutory directive is ambiguous and contains contradictions. Rather, as the IPA indicates, the statute requires the balancing of two objectives that are in some tension. To the extent there is any ambiguity, the policy goal of incentivizing new renewable energy projects, on which ComEd, NRG Companies, and Staff focus, should be considered in tandem with the goal of preserving budget for the other RPS programs. The Joint NGOs support the IPA's understanding of the relevant statutory language and its approach to implementing the Self-Direct Program crediting and accounting. JNGO Rep. at 1-2.

7. Staff's Position

For Staff, the goal of the Self-Direct Program credit should be that a relatively high percentage of the RPS charge is covered by the credit (allowing for a fraction of continued RPS charges to support preexisting contracts, the ABP, and ILSFA Program), not one where according to ComEd in the end a customer is paying 190% for RECs if it participates in the Self-Direct Program. Staff supports ComEd's alternative proposal for calculating the credit with the exception that Staff cannot support the \$4.77 being used as a proxy for future year's self-direct credits. Also, Staff finds the statute is clear that the credit must be recalculated yearly. Staff Resp. at 4-5.

Staff supports ComEd's methodology based upon an alternative reading of the law. Upon further consideration of Section 1-75(c)(1)(R)(4), it is clear to Staff that there are contradictions within the law as to what a self-direct credit is trying to achieve. It is now apparent to Staff; the law is ambiguous. The fundamental principle of statutory construction is to ascertain and give effect to the intent of the legislature. *Bowne of Chicago, Inc. v. Human Rights Comm'n*, 301 Ill. App. 3d 116, 119 (1st Dist. 1998). The

most reliable indicator of legislative intent is the statute's language, which must be given its plain and ordinary meaning. Where the statutory language is clear, it will be given effect without resort to other aids for construction. *Boaden v. Dept. of Law Enforcement*, 171 Ill. 2d 230, 237 (1996); Staff Resp. at 5.

Staff states, however, "if the language of a statute is ambiguous, courts may look to tools of interpretation to ascertain the meaning of a provision." *Ready v. United/Goedecke Servs., Inc.*, 232 Ill. 2d 369, 375 (2008). "A statute is ambiguous when it is capable of being understood by reasonably well-informed persons in two or more different senses." *Id.* at 377; *accord Commonwealth Edison Co. v. Ill. Commerce Comm'n*, 398 Ill. App. 3d 510, 524 (2d Dist. 2009). If a statute is ambiguous, "the court does not simply impose its own construction on the statute, as would be necessary in the absence of an administrative interpretation." *Commonwealth Edison Co. v. Ill. Commerce Comm'n*, 2014 IL App (1st) 132011 ¶ 20 (internal quotation marks omitted). Instead, "the question for the court is whether the agency's answer is based on a permissible construction of the statute. A court will not substitute its own construction of a statutory provision for a reasonable interpretation adopted by the agency charged with the statute's administration." *Id.* Staff finds that the statute is ambiguous as it pertains to the phrase "self-direct credit amount." Staff Resp. at 5-6.

While the IPA argues that the Plan's credit cannot punish Self-Direct Program customers since participation is voluntary, it is doubtful customers would participate if the credit is a disincentive rather than a financial incentive to join the program. Also, while the Joint NGOs argue P.A. 102-0662's goals of supporting smaller scale renewables, promoting equity, and developing energy sovereignty are not served by the Self-Direct Program, the Plan's Self-Direct Program credit - which provides little to no incentive for customer to become self-direct - would not appropriately implement a program clearly required under P.A. 102-0662. Finally, as ComEd points out, every new wind and new solar REC procured by a self-direct customer, is one less REC that has to be purchased under the RPS budget. Therefore, Staff maintains it is an incomplete statement for the IPA to simply state that every dollar credited back to self-direct customers, reduces the RPS funding available for RPS-related REC procurement initiatives. Staff Rep. at 10-11.

Staff states that, while the Commission certainly could adopt the Plan's proposed methodology, ComEd's proposal of using the average of actual procurement results for new utility scale or new wind projects would produce a better result and would spur participation in the Self-Direct Program compared to the LTRRPP's proposal. Staff Resp. at 6.

Staff notes that NRG Companies argue the Plan's proposal to provide bill credit values for the Self-Direct Program that change every year on a backward-looking basis would severely undermine the value of the Self-Direct Program. As an alternative, the NRG Companies propose that the Plan provide a Self-Direct participant with a fixed per kWh bill credit value that would extend through the entirety of the participant's REC contract. Staff Resp. at 6.

The relevant provision is the following:

... The Agency must determine the self-direct credit amount for new and existing eligible self-direct customers and submit

this to the Commission *in an annual compliance filing*. The Commission must approve the self-direct credit amount by *June 1, 2023 and June 1 of each delivery year thereafter*.

20 ILCS 3855/1-75(c)(1)(R)(4)(emphasis added). The phrase "self-direct credit amount" is ambiguous. Staff questions whether it is related to just new REC contracts for new and existing customers or related to both new contracts and preexisting new contracts for new and existing customers. Staff's understanding of NRG Companies' position is that they want the Self-Direct Program credit to be fixed throughout the entire term of a participant's REC contract. If that is NRG Companies' position, then Staff can support that objection. If, however, the NRG Companies want a single credit that does not change in the future for future projects, as ComEd seems to suggest, then Staff cannot support that aspect of the NRG Companies' proposal. Staff Resp. at 7.

NRG Companies complain that the Plan limits the availability of the Self-Direct Program and would disincentivize customers from procuring additional RECs beyond the 40% floor that is established by P.A. 102-0662. The Plan explains that "the self-direct credit operates in a binary matter-if a customer qualifies, then the entirety of the customer's volumetric RPS charges are credited accordingly. . . ." LTRRPP at 135. Staff maintains that the statute is ambiguous regarding whether participants should receive more credit for procuring additional RECs beyond the 40% threshold required to be eligible in the program. Staff Resp. at 13-14.

Section 1-75(c)(1)(R)(4) sets forth the manner in which the credit amount available to Self-Direct Program customers is calculated. Nothing in that provision, however, indicates that the credit amount should vary based on the number of RECs procured by a Self-Direct Program customer, or that additional credits are available to customers who procure RECs equivalent in volume to more than 40% of their annual usage. Staff therefore agrees with the LTRRPP, which states that "for additional REC retirements beyond 40%, the law does not contemplate an adjustment in crediting rate." LTRRPP at 139. Staff avers that this interpretation is reasonable and based on a permissible construction of the statute. Staff Resp. at 14.

In conclusion, Staff recommended the following with respect to the self-direct credit: 1) use ComEd's methodology for calculating the self-direct credit; 2) the credit amount using ComEd's methodology is locked in with respect to any projects entered into during the respective year; 3) on an annual basis a credit amount using the ComEd methodology would be calculated for new contracts for new projects entered into during the year by new and existing self-direct customers; and 4) for a self-direct customer that enters into contracts for multiple projects, the credit amount for that customer would be the weighted average based upon RECs of the previously determined Self-Direct Program credits for the respective projects entered into by the customer. Staff Rep. at 11-12.

8. IPA's Position

The IPA explains that new to Illinois law under P.A. 102-0662, Section 1-75(c)(1)(R) of the IPA Act provides for a large customer self-direct RPS compliance program to be established by the Agency through its 2022 Plan. This Self-Direct Program allows "eligible self-direct customers that purchase renewable energy credits from utility-

scale wind and solar projects through long-term agreements" to receive "a reduction in the volumetric charges collected pursuant to Section 16-108 of the Public Utilities Act" used to fund REC delivery contracts used to meet the Illinois RPS. Thus, in general terms, if a qualifying large customer enters into a qualifying contract to obtain and retire RECs from a qualifying utility-scale wind or utility-scale solar facility, then that customer may be charged less in Section 16-108(k) RPS collections than it otherwise would be, in recognition of that customer's commitment to privately secure RECs. IPA Resp. at 20.

The IPA points out that customers in the Self-Direct Program also retain rights to the RECs they purchase and retire, meaning they can make marketing or publicity claims about using the renewable energy associated with the RECs. The IPA asserts that arguments that the Self-Direct Program could act as a "disincentive" around private REC contracting are completely unfounded. The Self-Direct Program cannot punish customers who participate; it simply does not reward them as much as some Intervenors would like. If a qualifying customer finds that participation is not worthwhile, the IPA explains that it can simply choose not to participate and will simply pay proportionately the same in volumetric RPS charges as all other customers. IPA Resp. at 20-21.

Importantly, the IPA states, this Self-Direct Program is not an "opt-out" program. A large customer may still benefit from incentives for rooftop solar through the ABP or subscribe to a community solar project that obtained incentive funding through the ABP even while also separately self-procuring RECs to qualify for bill crediting under the Self-Direct Program. Similarly, while the ILSFA Program is generally intended to facilitate adoption of solar by low-income customers, 25% of ILSFA Program funding is dedicated to supporting solar development for not-for-profit customers and "public sector customers taking service at public buildings," with the latter category also eligible for the Self-Direct Program. IPA Resp. at 21.

ComEd - one of the parties that strenuously argues against the Plan's approach on the Self-Direct Program - admits that "many companies are interested in the [Self-Direct] Program - not because it is necessarily less expensive to acquire RECs on their own outside of the IPA's RPS programs - but because these companies have their own [Environmental, Social, and Governance] goals requiring that they purchase and retire RECs on their own to achieve these goals." The IPA opines that it would be nonsensical for the State to forfeit all payments into its RPS budget to fully or mostly refund these private entities for doing something for their own benefit that they may do anyway. IPA Rep. at 5-6.

Also, the IPA explains that every dollar credited back to participating customers under this Self-Direct Program through reduced charges then reduces the RPS funding available to support RPS-related REC procurement initiatives. As those customers may still participate in the ABP or ILSFA programs funded through Section 16-108(k) collections, the IPA suggests it is likely for this very reason - as well as related interests in RPS budget sufficiency and stability - that the available credit back to qualifying customers is limited to only "the anticipated cost of renewable energy credit deliveries under contracts for new utility-scale wind and new utility-scale solar entered for each delivery year after the large energy customer begins retiring eligible new utility scale renewable energy credits for self-compliance." 20 ILCS 3855/1-75(c)(1)(R)(4). Thus, self-procuring RECs from utility-scale projects can only relieve RPS costs associated with

RPS procurements from similar utility-scale projects and even then, cannot allow the self-direct customer to escape payment of RPS collection obligations for REC delivery contracts already executed for such facilities. IPA Resp. at 21-22.

Although already implied in what is authorized for calculating credits, the IPA notes a separate statement in Section 1-75(c)(1)(R)(4) makes express what is not authorized for inclusion in that credit: "the self-direct credit amount . . . does not include (i) costs associated with any contracts entered into before the delivery year in which the customer files the initial compliance report to be eligible for participation in the Self-Direct Program, and (ii) costs associated with procuring renewable energy credits through existing and future contracts through the Adjustable Block Program, subsection (c-5) of this Section 1-75, and the [ILSFA] Program." 20 ILCS 3855/1-75(c)(1)(R)(4); IPA Resp. at 22.

According to the IPA, this balancing of interests is essential in understanding the policy objectives of the Self-Direct Program. While one objective is to provide a credit back to participating customers to fairly compensate for privately procuring RECs and helping drive renewable energy project development, another objective is to ensure that the compensation to self-direct customers is not at the expense of the ABP, ILSFA Program, or funding available to meet any pre-existing REC delivery contracts. As every dollar credited through self-direct bill crediting reduces funds available to support other RPS initiatives, the General Assembly needed to balance these competing objectives- and not only ensure that the crediting level was sufficiently generous. IPA Resp. at 22.

The IPA explains that the significant majority of costs in Illinois RPS implementation are associated with the ABP or ILSFA Program. By law, those costs cannot be included in the self-direct bill credit. Not all RECs are created (or priced) equally: as ABP REC delivery contracts are used to support the development of smaller (e.g., rooftop solar) or more complicated (e.g., community solar) new renewable energy projects, REC prices applicable to the ABP are significantly higher, as the need for state-administered financial support per kW installed is proportionately much greater for these smaller and more complicated projects. Thus, while the REC price for a 200 MW utility-scale solar project may be \$4-\$8/REC, the REC price available for a 5 kW rooftop residential project may be \$70-\$80/REC. As 25% of Section 1-75(c)(1)(B)'s REC delivery targets are to be met through the ABP, these price differentials mean that a far greater portion of Section 16-108(k) collections are used to meet ABP costs than utility-scale procurement costs. IPA Resp. at 22-23.

Also, the IPA notes, these differences in relative costs were known and understood by the Illinois General Assembly when enacting P.A. 102-0662. Final REC prices for the ABP were filed in Docket No. 17-0838 in June 2018, and weighted average REC prices for utility-scale projects were released after the Commission vote approving each procurement event across 2017 to 2019. IPA Resp. at 23-24.

Thus, the IPA avers that the General Assembly was aware that by exempting ABP and ILSFA costs, and existing REC delivery contract costs, and by including only "the anticipated cost of renewable energy credit deliveries under contracts for new utility-scale wind and new utility-scale solar entered for each delivery year after the large energy customer begins retiring eligible new utility scale renewable energy credits for self-

compliance," the credit back to self-direct customers would be fairly small, as the share of those costs was known to be fairly small. IPA Resp. at 24.

Thus, the IPA explains that, as proposed in the LTRRPP, if \$9,000 of a large customer's \$10,000 monthly RPS charges support the ABP, ILSFA, and existing REC delivery contracts, and only \$1,000 supports utility-scale REC delivery contracts entered into after that customer's participation in the Self-Direct Program, then that customer may only be credited \$1,000. A more generous credit level will inherently include costs associated with the ABP, ILSFA Program, or existing REC delivery contracts-costs which cannot be included in the credit, as expressly stated in Section 1-75(c)(1)(R)(4). IPA Resp. at 24-25.

In addition, the IPA notes that Section 1-75(c)(1)(R)(3) of the IPA Act contemplates that the IPA "shall annually determine the amount of utility-scale renewable energy credits it will include each year from the self-direct renewable portfolio standard compliance program," and no party contests that the Self-Direct Program should allow new enrollment annually. Thus, some customers will begin participating upon the program's inception (2023), while others may begin participating in later years. However, because credits to participating Self-Direct Program customers may only include "the anticipated cost of renewable energy credit deliveries under contracts for new utility-scale wind and new utility-scale solar entered for each delivery year after the large energy customer begins retiring eligible new utility scale renewable energy credits for self-compliance" - and expressly cannot include "costs associated with any contracts entered into before the delivery year in which the customer files the initial compliance report to be eligible for participation in the self-direct program" - the costs eligible to be included in the credit varies based on the year in which the customer begins participation. This is because a customer beginning participation in 2023 will have a self-direct credit level that includes a different (and larger) universe of eligible REC delivery contract costs than a customer beginning participation in, say, 2025. The IPA explains that the 2023 customer's credit level may include utility-scale REC delivery contracts executed in 2023 and 2024, while for the customer beginning in 2025, it cannot. IPA Resp. at 25-26.

Moreover, because Section 1-75(c)(1)(G)(v) now employs an Indexed REC pricing structure for utility-scale wind and utility-scale solar projects, the IPA explains that actual costs associated with those new utility-scale REC delivery contracts will vary by delivery year. Should wholesale energy prices in a given delivery year rise, then Indexed REC prices will fall; should wholesale energy prices fall, then Indexed REC prices will rise. As utility-scale solar and wind REC delivery contracts costs used to determine the self-direct credit will themselves change annually, the self-direct credit level "shall be determined annually," and the LTRRPP outlines the IPA's proposed process for doing so. IPA Resp. at 26.

Third, the IPA states because self-direct crediting cannot include "costs associated with any contracts entered into before the delivery year in which the customer files the initial compliance report to be eligible for participation in the self-direct program" (20 ILCS 3855/1-75(c)(1)(R)(4)), costs which are eligible to be included in establishing self-direct crediting levels will not be eligible to be credited back to participating Self-Direct Program customers until years after that customer is accepted into the Self-Direct Program. A utility-scale wind or solar contract only features costs when those systems are energized,

and energization may take three to five years. Until energization, the costs to the RPS associated with those new utility-scale contracts are zero and providing a credit back to a self-direct customer across that period would inherently then reduce the budget available to the ABP, ILSFA Program, or utility-scale projects "entered into before" the customer's participation. The Self-Direct Program thus features a lag between participation and crediting, as upon participation, there will be no immediate costs featured in the universe of REC delivery contract costs which may be included in self-direct credits. IPA Resp. at 26-27.

The IPA suggests that these are not discretionary choices made by the IPA but are simply the application of the express language found in Section 1-75(c)(1)(R)(4) of the IPA Act. IPA Resp. at 27.

The IPA notes that NRG Companies offer an argument that because recipients of Indexed REC contracts receive revenue certainty, Self-Direct Program participants should "receive at least a similar level of certainty" as well. The IPA posits that self-direct customers receive that certainty through the bilateral contracts they negotiate for the procurement of RECs. They may pay whatever price they wish for those RECs, with pricing structured however they wish-including through contracts mirroring the Indexed REC pricing structure employed through Section 1-75(c)(1)(G)(v). Those separate agreements are not at issue in this proceeding. All that is at issue is what level of RPS charges are discounted based on the presence of such qualifying contracts, and NRG Companies make no attempt at arguing how a fixed discount in RPS charges would be consistent with Section 1-75(c)(1)(R)(4) of the IPA Act when the very costs upon which that discount is to be based change year over year. IPA Resp. at 32-33.

With respect to NRG Companies' proposal that self-direct customers' credit should be prorated based on their level of REC procurement, the IPA states that either a self-direct customer's REC procurements meet the 40% threshold, and that customer may participate and receive bill crediting, or they do not, and no credit is provided. Nowhere does Section 1-75(c)(1)(R) contemplate varying levels of participation with correspondingly varying credit levels. IPA Rep. at 11.

In response to ComEd's statement that it simply is not plausible that the economics of the General Assembly's new Self-Direct Program would so dramatically discourage, if not effectively penalize, participation, the IPA states that it is impossible for a voluntary discount to penalize participation, even if that discount is not as high as ComEd would prefer. Also, as every dollar credited back to customers reduces the funds otherwise available for expenditure under the Illinois RPS, the IPA states that the General Assembly had to balance the value of providing a more generous credit to customers with ensuring that existing REC delivery contracts and vital programs were sufficiently supported. That balancing is outlined in the specific costs that may be included in the credit as outlined in Section 1-75(c)(1)(R)(4). IPA Resp. at 27-28.

The IPA notes that ComEd next questions why a customer would agree to terms requiring accelerated achievement of the 2030 RPS goal while continuing to pay nearly all of the monthly RPS charge. In the IPA's view, it is because: a) that customer has their own corporate or municipal sustainability goals to meet (as those customers do not relinquish any rights to the RECs through the Self-Direct Program) and b) without

participation, the customer will pay all the monthly RPS charge. In other words, the IPA explains that a customer receives a moderate reprieve in monthly RPS charges for achieving its own sustainability goals. IPA Resp. at 28.

ComEd then claims that it attempts to "reconcile" competing language by simply selecting a proxy price per REC and claiming that this proxy price can be credited back to customers under the law. This approach fails for at least the following reasons. First, the IPA maintains that ComEd conflates "prices" (the term ComEd uses in developing its "proxy" value) with "costs" (the term actually found in the law). ComEd proposes a "proxy" price based on prices observed under past contracts (despite an express statement in the law that those contracts' costs cannot be considered in crediting), claiming that this proxy price can somehow serve as the self-direct crediting level. But prices are not costs. Prices are a component of costs, but costs also have a quantity- and time-based component. The law recognizes those additional components expressly by only authorizing crediting based on the "anticipated cost of renewable energy credit deliveries under contracts for new utility-scale wind and new utility-scale solar entered for each delivery year after the large energy customer begins retiring eligible new utility scale renewable energy credits for self-compliance," while excluding "costs associated with any contracts entered into before the delivery year in which the customer files the initial compliance report to be eligible for participation in the self-direct program." 20 ILCS 3855/1-75(c)(1)(R)(4); IPA Resp. at 28-29.

The IPA argues that ComEd's approach allows participating self-direct customers to avoid the very costs that Section 1-75(c)(1)(R)(4) states cannot be included in the self-direct credit. By way of example, the 2023-24, 2024-25, and 2025-26 delivery years will feature certain costs to the RPS budget based on various categories of REC delivery contracts. Customers are charged a pro rata share of those costs as a volumetric charge on their utility bill. Customer collections from that year (or potentially pulled forward from years' prior, if unspent) are used to meet those costs, ensuring that the delivery year's REC delivery contract payment obligations are met. IPA Resp. at 30.

The IPA states that it is fully aware that by virtue of a large customer self-procuring RECs, the overall REC delivery targets for only utility-scale projects will be reduced. However, under ComEd's "proxy" price methodology, the participating customer who only procured utility-scale RECs would then be excused from payment obligations used to support the ABP or ILSFA Program. These programs work to achieve vital policy goals, of equity, grid resiliency, low-income customer support, and democratization of energy supply above and beyond a simply quantitative REC exchange. This is exactly why the Illinois General Assembly did not provide a near-full credit against the RPS charge, as ComEd wishes, and instead expressly exempted ABP and ILSFA costs from being included in crediting. This exemption is ignored under ComEd's methodology, which excuses customers from 95% of RPS charges. Simply stated, ComEd's approach to bill crediting is unlawful, and must be rejected. IPA Resp. at 31-32.

The IPA notes that the City requests that the self-direct bill credit be "a more effective incentive" for new project development, but provides no analysis of Section 1-75(c)(1)(R)(4)'s express language, how the IPA's application of Section 1-75(c)(1)(R)(4)'s language is in error, or how Section 1-75(c)(1)(R)(4) can be read to provide a more generous credit back to a large customer. Again, the merits of providing a more

generous-or "effective"-credit back to a participating large customer must be balanced against the detrimental impacts on the RPS budget of that crediting. The General Assembly has balanced those objectives by stating that while Self-Direct Program bill crediting is authorized for qualifying customers, those credits may only include utility-scale REC delivery contract costs for contracts entered into after the customer's Self-Direct Program participation. That was the "legislature's intent," as it was expressed through the carefully chosen language found in Section 1-75(c)(1)(R)(4). By contrast, nowhere within the IPA Act did the legislature state that a self-direct crediting level should be generous enough to satisfy all potential large customers that apply. IPA Resp. at 33-34.

The IPA suggests that the City is welcome and encouraged to pursue whatever sustainability objectives it wishes. All that is at issue in this proceeding is what level of RPS-related charges it can avoid in doing so. As the City has provided no arguments for how a more generous credit can be supported under Section 1-75(c)(1)(R)(4)'s language - let alone how more generous bill crediting would not injure the very programs it seeks to ensure are supported as its "grounding principle" - its arguments must be rejected. IPA Resp. at 34.

The Joint NGOs support the IPA's proposed approach and assert that it appropriately balances the goals of ensuring high-quality RECs from new renewable energy projects and sufficiently maintaining the RPS budget for the ABP and the ILSFA program. While the Agency appreciates the Joint NGOs' support, it disagrees that the Agency or Commission has the authority to "balance" these competing interests. Rather, the General Assembly already determined that balance when it explicitly directed that the self-direct credit "not include . . . costs associated with procuring renewable energy credits through existing and future contracts through the Adjustable Block Program, subsection (c-5) of this Section 1-75, and the [ILSFA] Program." IPA Rep. at 12-13.

The IPA notes that NRG Companies also briefly raise an argument about the Agency 'holding back' funds by not expending the full RPS budget in each delivery year. The Agency's modeled expenditures are those anticipated to meet RPS statutory minimums. It is true that they do not take the budget down to zero in each year, for multiple reasons. First, the Agency's Plan builds up a reserve of funds in the early years, which is then spent down later. Second, when the Agency contracts for RECs from new resources, there is a lag of up to several years between when funds are committed and when they are actually spent. Third, REC prices may fluctuate, and the Agency believes it is appropriate to include a buffer in its proposed expenditures to account for market variation; no party contests that buffer. Nevertheless, the IPA states that NRG Companies vastly overstate the RPS budget balance by relying upon substantially inaccurate numbers. Moreover, it is unclear to the IPA what NRG Companies' point actually is and notes that the Agency following fiscally responsible budgeting practices does not change the statutory directive for how to calculate Self-Direct Program credits. IPA Rep. at 17.

The IPA suggest that Staff's position on the topic of self-direct crediting is similarly misguided. Staff begins by explaining:

For Staff the goal of the Self-Direct credit should be that a relatively high percentage of the RPS charge is covered by

the credit (allowing for a fraction of continued RPS charges to support preexisting contracts, the Adjustable Block Program, and the Illinois Solar for All Program), not one where according to ComEd in the end a customer is paying 190% for RECs if it participates in the self-direct program.

In the IPA's opinion, Staff is not charged with determining the "goal of the Self-Direct credit"; rather, Staff's role is defined under Section 2-105 of the PUA as carrying out the provisions of the PUA - that is, assisting the Commission in its approval of a Long-Term Plan that will "accomplish the requirements of ... subsection (c) of Section 1-75 of the Illinois Power Agency Act." Instead, the Staff begins with policy goals apparently adopted from for-profit Intervenor and attempts to rewrite the statute to fit, declaring that - after reading the arguments of ComEd and NRG, and after having offered none of its own - "[i]t is now apparent" that "the law is ambiguous." The IPA notes that Staff points to no ambiguity in the law regarding how that self-direct credit is calculated in the first place and provides no support for the assertion that ComEd's alternative methodology can be squared with the letter of Section 1-75(c)(1)(R)(4) of the IPA Act. IPA Rep. at 17-19.

Staff then turns to the issue of how the self-direct credit applies. The law states that "[t]he self-direct credit amount shall be determined annually." Despite this clear and unambiguous language, Staff supports NRG Companies' proposal that the self-direct credit be locked in, beginning in year 1, for the duration of each self-direct customer's private REC contracts. In other words, the self-direct credit would be established on an annual basis - but only for new contracts entered into by self-direct customers in that year. IPA Rep. at 19.

In an attempt to demonstrate alleged ambiguity in the law, Staff presents two alternative versions of the statute. Staff's reading simply has no basis in the law and creates implementation issues that force Staff to impute additional details—including calculating an individual customer's credit amount using the weighted average of credit amounts for different REC contracts—in a snowballing proposal detached from statutory language. Accordingly, the IPA avers that Staff's arguments in support of NRG Companies' proposal must be rejected by the Commission. IPA Rep. at 19-20.

9. Commission Analysis and Conclusion

Section 1-75(c)(1)(R) provides in relevant part that the Self-Direct Program customer credit must be calculated as follows:

The Commission shall approve a reduction in the volumetric charges collected pursuant to Section 16-108 of the Public Utilities Act for approved eligible self-direct customers equivalent to the anticipated cost of renewable energy credit deliveries under contracts for new utility-scale wind and new utility-scale solar entered for each delivery year after the large energy customer begins retiring eligible new utility scale renewable energy credits for self-compliance. The self-direct credit amount shall be determined annually and is equal to the estimated portion of the cost authorized by subparagraph (E) of paragraph (1) of this subsection (c) that supported the

annual procurement of utility-scale renewable energy credits in the prior delivery year using a methodology described in the long-term renewable resources procurement plan, expressed on a per kilowatt-hour basis, and does not include (i) costs associated with any contracts entered into before the delivery year in which the customer files the initial compliance report to be eligible for participation in the self-direct program, and (ii) costs associated with procuring renewable energy credits through existing and future contracts through the Adjustable Block Program, subsection (c-5) of this Section 1-75, and the Solar for All Program. The Agency shall assist the Commission in determining the current and future costs.

20 ILCS 3855/1-75(c)(1)(R)(4). The Commission finds, as argued by several parties, that the first and second sentence of this provision are the most difficult to interpret. The Commission cannot approve a reduction or credit for self-direct customers that is both forward-looking and backward-looking. The Commission finds that the statute is ambiguous as it pertains to the phrase "self-direct credit amount."

As noted by Staff, if a statute is ambiguous, "the court does not simply impose its own construction on the statute, as would be necessary in the absence of an administrative interpretation." *Commonwealth Edison Co. v. Ill. Commerce Comm'n*, 2014 IL App (1st) 132011 ¶ 20 (internal quotation marks omitted). Instead, "the question for the court is whether the agency's answer is based on a permissible construction of the statute. A court will not substitute its own construction of a statutory provision for a reasonable interpretation adopted by the agency charged with the statute's administration." *Id.* Importantly, the statute expressly allows the IPA to include the methodology in the LTRRPP, which is a clear indication that the legislature granted the IPA discretion in implementing the Self-Direct Program. Although Staff does not recommend the IPA's approach, Staff notes that if the Commission finds the statute to be ambiguous, the Commission can adopt the LTRRPP's proposed methodology. Staff Rep. at 11.

Although the first two sentences in Section 1-75(c)(1)(R)(4) of the IPA Act are the most unclear, the remainder of the statutory paragraph is somewhat clearer. Because the IPA's proposal to calculate the Self-Direct Program credit as a portion of the RPS charge adheres to the rest of the paragraph more closely, it is adopted, but not in its entirety as explained in more detail below. In particular, ComEd's and NRG Companies' methodologies are essentially designed as a REC payment and not a credit to the RPS charge. The Commission finds compelling both the language in the first sentence that it is to be a reduction in the RPS charge and in the second sentence that it is the "estimated portion of the cost ... that supported the annual procurement of utility-scale renewable energy credits." ComEd's and NRG Companies' proposals are not adopted.

In addition, the Commission agrees with the IPA that there is nothing unclear about the direction to exclude costs associated with the ABP and ILSFA. The Commission notes that ComEd and the IPA frame this question differently. ComEd focuses on the overall budget amounts whereas the IPA focuses on what portion of a customer's RPS charge supports the different programs. Because the statute directs that the credit is to

be a portion of the charge, the IPA's understanding of the statutory language is consistent with the overall direction in this paragraph regarding how the credit is supposed to be calculated. Also, as proposed by ComEd, the Self-Direct Program credit becomes almost an opt-out, but Self-Direct Program participants can still participate in the ABP, or even ILSFA if they are a public entity. The IPA's proposal correctly implements the requirement that the Self-Direct Program credit not impact the ABP and ILSFA programs.

The Commission notes that parties offer many policy arguments in support of both the ComEd/NRG Companies' proposals and the IPA's proposal. The Commission is not convinced by arguments that the IPA's proposed Self-Direct Program credit will be a disincentive to participation. The Commission notes that ComEd even suggests that many companies are interested in the Self-Direct Program – not because it is necessarily less expensive to acquire RECs on their own outside of the IPA's RPS programs, but because these companies have their own environmental, social, and governance goals requiring that they purchase and retire RECs on their own to achieve internal goals. ComEd Obj. at 10. The Self-Direct Program helps these companies pay for RECs that they intended to purchase anyway. Indeed, the City has its own climate goals and the Self-Direct Program credit, at whatever level it is set, will reduce the cost for the City to meet those goals.

The Commission notes Table 6-1 in the LTRRPP lists six sample corporate REC procurement agreements for new utility-scale wind and solar developments in Illinois that began or will begin operating from 2015 to 2022 (totaling 765 MW). The companies entered into these agreements without any known incentive from a Self-Direct Program. IPA Rep. at 14-15. NRG Companies claim that Self-Direct Program RECs are more economical than RPS RECs, but the most economical clean energy for the State of Illinois is the clean energy that customers procure for themselves such as these listed by the IPA.

With respect to the proposal by NRG Companies that the Self-Direct Program credit should vary based on the percentage of a customer's usage for which it has procured RECs, the Commission does not adopt this proposal. The 40% threshold in the statute is an eligibility criteria, nothing in the statute suggests that the credit should be scaled based on the level of RECs purchased.

NRG Companies also propose that the Commission adopt an approach that would provide a Self-Direct Program participant with a fixed per kWh bill credit value that would extend through the entirety of the participant's REC contract. The Commission finds that the IPA's proposed implementation of the requirement to annually calculate the credit, which provides different credit levels based on a customer's date of enrollment, instills too much instability for Self-Direct Program participants. Also, with the advent of the strike price and increased energy prices, the amount of the Self-Direct Program credit could vary drastically.

The IPA's proposal only relies on the first sentence of the above-quoted language in that it is strictly forward-looking. ComEd's proposal takes an average of REC prices to reach its proposed proxy, recognizing the inconsistency between the first and second sentences. Although the Commission does not adopt ComEd's proposed credit based on REC prices, the Commission finds that an average to reflect these statutory

inconsistencies is appropriate. The Commission is further convinced that the IPA's methodology is unreasonable because the IPA suggests the Self-Direct Program features a lag between participation and crediting and "there will be no immediate costs featured in the universe of REC delivery contract costs which may be included in self-direct credits." IPA Resp. at 26-27.

The Commission finds that it is more appropriate that a three-year rolling average of eligible utility-scale REC delivery contracts be used, consisting of the two-years prior to the year being determined and the third year being the anticipated costs as outlined in the LTRRPP. This addresses the variable REC prices that may be forthcoming and the point raised by NRG Companies that in some years the IPA has no eligible procurements.

The Commission recognizes that it could be argued that this conclusion violates the second sentence that excludes the credit from including "costs associated with any contracts entered into before the delivery year in which the customer files the initial compliance report." But arguably this exclusion conflicts with the first half of the same sentence that says the credit "is equal to the estimated portion of the [RPS charge] that supported the annual procurement of utility scale [RECs] in the prior delivery year." And of course, the second sentence conflicts with the first sentence that requires the credit to be equivalent to the "anticipated cost of [REC] deliveries under contracts for new utility-scale wind and new utility-scale solar entered for each delivery year after the large energy customer begins retiring eligible new utility scale [RECs]." With these inconsistencies in the statutory language, using an average to determine an annual credit amount is reasonable.

A three-year rolling average cuts down on unnecessary complexity that requires a different credit calculation based on when a customer's participation begins, as proposed by the IPA. It also avoids the complexity of Staff's proposal that would require a weighted average being determined based on when a customer's various REC contracts were initiated.

The IPA is directed to amend the LTRRPP in accordance with these conclusions.

C. Section 6.5.1.3 Self-Direct Bill Crediting: Compliance Filing

1. Staff's Position

Staff recommends an alternative to the IPA's proposal that any self-direct credit compliance filing not objected to by a party successfully shall be deemed approved by the Commission. Staff proposes that the Commission take an overt action every year to approve the self-direct credits. Staff recommends that the Commission process for approving self-direct credits be handled in the same manner as the Commission approves benchmarks. See LTRRPP, Section 5.8. Specifically, every year after the IPA compliance filing and after allowing sufficient time for parties to contest the filing, the Commission shall place on its agenda a vote to approve the self-direct credit. Staff Obj. at 7.

2. NRG Companies' Position

NRG Companies agree with Staff's position as it ensures a positive approval of incentives levels which can be a protection against subsequent misunderstandings,

mistakes, or reversals that could negatively impact the interests of consumers participating in the Self-Direct Program. NRG Resp. at 6.

3. IPA's Position

The IPA states that it supports the inclusion of Staff's proposal of a Commission vote to approve the crediting levels in the LTRRPP. As Section 1-75(c)(1)(R)(4) expressly states that the Commission "must approve" self-direct crediting levels, and not merely receive or accept that compliance filing, a Commission vote leaves no ambiguity around whether this requirement was met. Ultimately, the IPA hopes that: a) clarity from this Plan approval proceeding on the self-direct bill crediting methodology and b) proactive stakeholder engagement on self-direct bill crediting levels before filing will minimize the likelihood of bill crediting challenges. IPA Resp. at 35.

4. Commission Analysis and Conclusion

The Commission notes that the relevant statutory language states:

The Agency must determine the self-direct credit amount for new and existing eligible self-direct customers and submit this to the Commission in an annual compliance filing. The Commission must approve the self-direct credit amount by June 1, 2023, and June 1 of each delivery year thereafter.

20 ILCS 3855/1-75(c)(1)(R)(4). The Commission finds that Staff's proposal properly implements the statutory requirement that the Commission approve the self-direct crediting levels. It is adopted.

VI. CHAPTER 7 ADJUSTABLE BLOCK PROGRAM

A. Section 7.3.4 Opening of 2022 Delivery Years Blocks & Subsequent Annual Block Openings.

1. IPA's Position

As directed by P.A. 102-0662, the 2022 Long-Term Plan effectuates a transition from blocks of available capacity defined by a set number of MW to blocks of capacity available for each delivery year. The IPA explains that for the delivery year beginning on June 1, 2022, this new structure poses a challenge given that the LTRRPP establishing the program rules and requirements for that delivery year will not be approved by the Commission until July 19, 2022. To resolve this misalignment, the LTRRPP proposed a pause in new project applications from June 1 to August 1, 2022, and no party has contested that pause. In its Reply Comments, the Agency is now proposing to shift that pause in applications to July 1 – September 1, 2022, due to several considerations, outlined below. IPA Rep. at 21.

First, the IPA has awarded a contract to a new Program Administrator for the ABP, which was approved by the Commission on April 21, 2022. The contract with the current Program Administrator will end on June 30, 2022, with the new Program Administrator taking over on July 1, 2022. Continuing to accept applications through the month of June will align better with the transition to the new Program Administrator. Pausing applications for July and August will allow the current Program Administrator to address all outstanding issues and process applications through the end of its contract, while also allowing the

new Program Administrator time to set up new systems and integrate new program requirements approved by the Commission in the LTRRPP. IPA Rep. at 21.

Second, based on extensive stakeholder feedback on the time needed to prepare a Community-Driven Community Solar (“CDCS”) project application, the ABP Guidebook requires that the submission window for the first block of the new CDCS category in the ABP remain open until June 12, 2022. Pausing acceptance of new applications for other ABP categories while continuing to accept new project applications for the CDCS category will engender unnecessary confusion among both Approved Vendors and the public. By shifting the suspension of new applications to July 1, 2022, the IPA will be able to apply that pause across ABP categories and maintain a consistent message across constituencies and projects. IPA Rep. at 21-22.

Third, and relatedly, the IPA included this planned pause in its proposed Plan but recognizes that not all interested parties will have read the Plan or done so with sufficient care to note this important element. Neither the Agency nor the current Program Administrator have separately notified Approved Vendors and Designees of this planned pause, which as initially proposed would begin in less than three weeks, and the IPA is concerned that few program participants are aware of this deadline. This lack of communication could cause major disruption for project developers and the Agency wishes to provide sufficient advance notice of the pause to prevent unnecessary confusion. Delaying the start of the pause in new applications until July 1st will allow the current Program Administrator to plan and execute a full communications strategy to ensure clear, consistent messaging to all Approved Vendors and Designees not only about the date that the pause begins, but the timeline going forward. That way, program participants can prepare their project pipeline accordingly. IPA Rep. at 22.

Fourth, the Commission is expected to provide an Order approving the new Long-Term Plan (including any changes thereto) on July 14, 2022. Reopening the ABP for new project applications on August 1, while feasible, would be extremely difficult, especially given the transition to a new Program Administrator. Given the other interests that also weigh in favor of shifting the pause to begin July 1, allowing more time for the Agency and the new Program Administrator to integrate any new Program elements or requirements into the application portal would be eminently reasonable. IPA Rep. at 22-23.

Finally, those additional weeks would also allow the IPA to publish new REC prices based on the formulae approved by the Commission in the Long-Term Plan by August 1, 2022 and provide stakeholders several weeks to review them. This would further allow project developers to better plan their project pipeline to be ready for the application reopening on September 1, 2022. For this and the above reasons, the Agency believes it to be in the best interest of the ABP and the Illinois distributed solar generation sector to shift the already-planned (and heretofore uncontested) pause on new applications to July 1 – September 1, 2022. IPA Rep. at 23.

2. Commission Analysis and Conclusion

No party had the opportunity until exceptions to object to this proposal to shift the pause from June 1 – August 1 to July 1 – September 1, 2022. The Commission notes

that no party filed exceptions to this proposal. The IPA's proposal appears reasonable and therefore is adopted.

B. Section 7.3.5 Uncontracted Capacity at the Close of a Delivery Year

1. Joint Solar Parties' Position

The Joint Solar Parties note that the General Assembly decided to reconcile the competing interests of top-line ABP procurement goals (1-75(c)(1)(C)) and carve-outs of capacity within the ABP (1-75(c)(1)(K)) with a mechanism to reallocate unused capacity at the end of a delivery year. The mechanism has very few requirements other than allowing reallocation such that the statutory program minimums are not implicated. JSPs Obj. at 33.

As the ABP both restarts incumbent programs and creates new programs such as the Equity Block and the Schools Block, the Joint Solar Parties believe there should be a balance between reallocating capacity to blocks with higher demand (reflected by a waitlist) and preserving the legislatively-directed division of ABP capacity. JSPs Obj. at 33.

Outside of protecting the Equity Block, the Joint Solar Parties object to the remainder of the reallocation proposal. The Joint Solar Parties note that the LTRRPP's proposed approach focuses too much on waitlists as the programs are starting up—especially in light of the potential for certain categories to generate substantial waitlists while other categories are still experiencing ramp-up (like the Community-Driven Community Solar Block) or fixing program issues (like the Public Schools Block). In these first few years, the Joint Solar Parties urge the IPA to weigh preserving programs as they begin to ramp up (and attract developers) against quickly procuring RECs. JSPs Obj. at 34.

In order to provide an early-year solution that does not completely raid capacity assigned to blocks that for different reasons are not expected to fully exhaust their capacity, the Joint Solar Parties propose an interim approach to reallocation of unused capacity. JSPs Obj. at 34-35.

Although only noted specifically with respect to the Equity Block, the Joint Solar Parties recommend that the IPA seek stakeholder feedback on barriers for any program that fails to fill blocks in both 2021-22 and 2022-2023. The Joint Solar Parties understand there is a substantial appetite for new development and acquisition and many developers are active in or looking at Illinois, so continually under-filled blocks may be an indication of one or more barriers to success. JSPs Obj. at 35.

In response to the JSPs' proposal, the IPA proposes to shift the balance between early deployment and new program preservation much further toward favoring new program preservation by leaving all 2021-22 block unused capacity in the Public School and community-driven community solar categories in place and reallocating only 50% of unused capacity in the 2022-2023 block. While the Joint Solar Parties prefer the balance of their approach in Objections, the Joint Solar Parties believe the IPA's proposal in its Response Comments is superior to the IPA's original proposal. JSP Rep. at 34-35.

2. Staff's Position

Staff does not support the JSPs' objection. For the reasons set forth in the Plan, Staff finds the Plan's proposal to be more efficient than the JSPs' proposal. In its Response Comments, the IPA agreed that there is merit to the JSPs' arguments that capacity for the early years of new categories should be reserved. Staff does not object to IPA's proposed revisions to the Plan. Staff Rep. at 35.

3. IPA's Position

The IPA believes that there is merit to the Joint Solar Parties' arguments that capacity for the early years of new categories should be preserved. The Agency agrees that there is potential for well-established categories—Small Distributed Generation (“DG”), Large DG, and Traditional Community Solar—to generate waitlists while the emerging categories—Equity Eligible Contractor, Public Schools, and Community-Driven Community Solar—ramp up and begin to attract market participants. Under the requirements of P.A. 102-0662, the Agency had 90 days available to develop requirements and reopen these new categories prior to December 14, 2021. Consequently, solar developers have had a short amount of time to become familiar with the program requirements for these new categories and begin to develop projects that meet those requirements. This is reflected in the current applications for these new categories; as of the date of Response Comments, one Part I application in the Public Schools category has been initiated but not submitted, three Part I applications in the CDCS category have been initiated and another has been submitted, and no applications in the EEC category have been created. IPA Resp. at 37-38.

Given the low up-take in the new categories to date, the Agency is not convinced that the Joint Solar Parties' proposal goes far enough in preserving capacity in emerging categories during their nascent development. Accordingly, the Agency proposes a new approach to reallocation for the Public Schools and CDCS categories only. The Agency proposes that all unused capacity from blocks within these categories that opened on December 14, 2021, will be rolled over to the 2022-2023 delivery year. The Agency proposes that unused capacity within these two categories that remains unused at the end of the 2022-2023 delivery year would be split, with 50% of the capacity remaining in each of those two categories, and 50% redistributed as outlined in the filed Plan. The Agency believes that this will continue attracting market participants to these categories and provide adequate time for meeting the recently-established requirements for each category. IPA Resp. at 38.

4. Commission Analysis and Conclusion

The Commission adopts the proposal outlined in the IPA's Response Comments. The Commission finds that it appropriately leaves in place all the unused capacity in the 2021-22 block in the Public School and CDCS categories and reallocates only 50% of unused capacity in the 2022-2023 block. The Commission agrees with the JSPs proposal that if substantial unused capacity remains in the Equity Block, the IPA should work with stakeholders to identify barriers and a plan to mitigate those barriers.

C. Section 7.4.3 Traditional Community Solar

1. Joint NGOs' Position

The Joint NGOs agree with the IPA that it is likely that applications for Traditional Community Solar projects will continue to exceed block capacity and the Joint NGOs generally support the IPA's proposed scoring system to manage projects submitted "at the same time" and any resulting waitlist. Once projects are ranked on a waitlist, the Joint NGOs believe that the IPA is clear in its intent to select projects from it, in order, as capacity becomes available. While the Joint NGOs recognize that the statute requires that "the waitlist of projects in a given year will carry over to apply to the subsequent year when another block is opened," the Joint NGOs are concerned that such a "carry over," without any opportunity to re-rank the projects on an annual basis according to the IPA's scoring system, would be problematic. 20 ILCS 3855/1-75(c)(1)(K); see *also* Plan at 165. Specifically, this approach may penalize projects that take longer to develop and apply, which may nonetheless have more characteristics that P.A. 102-0662 seeks to encourage, such as participation by Equity-Eligible Contractors or brownfield siting. The Joint NGOs suggest that the Commission require the IPA to "carry over" its waitlist and not require waitlisted projects to reapply, but to re-rank waitlisted projects along with any new projects submitted on the first day of each delivery year, according to the IPA's scoring system. JNGO Resp. at 13.

In the Plan, the IPA does not propose to require community solar program applicants to have a signed interconnection agreement ("ICA") within its technical system requirements in Section 7.9.1. Subject to the additional recommendations below, the Joint NGOs support the IPA's proposal to remove the requirement for a signed ICA for community solar applicants, based on the past negative experiences with the resulting effects on interconnection queues and the associated uncertainty regarding the agreement's ability to indicate project maturity or viability. With respect to the interconnection procedures, while the updated deposit requirement should help to encourage mature projects, the deposit is refundable, which may still allow for speculation. Moreover, the Joint NGOs note that the ultimate implementation date of the amended Part 466 interconnection procedures is currently uncertain, and it is possible that updated utility procedures reflecting the rule will not be in place when the community solar program block opens. JNGO Rep. at 3-4.

Additionally, the Joint NGOs note that in ComEd's interconnection queue alone, 683 MW of community solar projects have already applied to interconnect (with 104 projects with 239 MW of capacity showing a status of construction pending) in advance of the release of the next block of capacity. Therefore, it is likely that, even if the Commission accepts the JSPs' proposal to require a signed interconnection agreement, projects applying to the program on the day it opens will far exceed available capacity. JNGO Rep. at 4-5.

As an alternative approach to achieving the goal that the Joint NGOs share with the JSPs - discouraging speculative projects from applying to the ABP and entering the ABP queue - the Joint NGOs believe the IPA's scoring process could be further enhanced by the incorporation of a threshold requirement for a certain number of points in order to enter the queue. If set appropriately, a threshold point requirement could ensure that all

projects accepted into the program meet a minimum set of criteria and thus avoid speculative or immature projects. In response to the JSPs' concerns, the Joint NGOs would be open to the inclusion of an additional interconnection scoring component, potentially awarding points for having a current, signed ICA, with additional points for distribution facilities upgrade costs committed and other interconnection-related criteria, if incorporated in combination with such a threshold points requirement. The Joint NGOs encourage the Commission to require the IPA to incorporate a threshold points requirement and to solicit stakeholder feedback regarding the appropriate number of points to require and other implementation details. JNGO Rep. at 5.

The Joint NGOs maintain that if neither re-ranking nor a threshold points requirement is in place, project developers may be incentivized to submit speculative projects on the day the upcoming block opens in order to secure a spot on the waitlist, even if they would receive low scores, rather than spending time to make modifications to obtain higher scores and better achieve the program's goals. Such an incentive would run counter to the program's policy objectives and could indefinitely block other, higher-scoring projects submitted in future delivery years from moving ahead. JNGO Rep. at 6.

2. US Solar's Position

US Solar states that there are two elements of the Traditional Community Solar tie-breaker preferences that could significantly benefit from the additional changes. US Solar Obj. at 2. US Solar supports the adoption of the "agrivoltaics or dual use" ("Ag/dual use") tie-breaker preference, but only if the Plan includes a workable compliance requirement to ensure that applicants cannot game the system by securing the preference without then implementing Ag/dual use solar practices. Neither the term "agrivoltaics" nor "dual use" is defined in the Petition or the 2022 Plan; each term appears only once in the LTRRPP at 164. That could be a real risk making it potentially difficult to hold an applicant to their commitment to adopt Ag/dual practices over the 20-year project term. The IPA could conceivably develop a working definition and/or minimum standard for Ag/dual use solar over time (e.g., through a future stakeholder workshop process), but it would not be appropriate to retroactively apply any such future minimum standards to Traditional Community Solar projects that applied for program capacity before the new standard is approved. US Solar Obj. at 2.

That said, US Solar can also appreciate and respect that the Agency still wants to move forward with this preference, perhaps in the hope that it will kick-start the first wave of Ag/dual use solar projects in the state and enable applicants to start learning by doing. Toward that end, US Solar respectfully suggests the adoption of procedural (not substantive) compliance requirements that will enable operational flexibility and shared learning while also addressing the gaming concern mentioned above. Specifically, US Solar urges the adoption of a biennial (every two year) reporting requirement once the project starts operation, to allow flexibility while requiring transparency into the operator's good-faith efforts to implement Ag/dual use solar practices that are appropriate and workable for the individual project site. Depending on the Agency's level of interest in learning about and sharing information on emerging Ag/dual use solar practices within the Traditional Community Solar, the Agency may also want to add a biennial site-walk compliance requirement (i.e., so staff can physically visit the project site with the operator and observe the site-specific Ag/dual use practices). US Solar Obj. at 2-3.

US Solar also notes that the Plan proposes a 2-point tie-breaker preference for new Traditional Community Solar projects sited in a county or township that does not contain other approved community solar projects. The Plan seemingly creates an exception for six specific counties: Cook, DuPage, Kane, Lake, McHenry, or Will County. Although the Petition does not explain the basis for this proposed modification, US Solar appreciates that there may be good reasons to consider geographic distribution separately for Group A (Ameren) and Group B (ComEd). Unfortunately, the Agency's proposed language is not clear and could be wrongly interpreted as establishing special preferences for certain specified counties without regard to the larger energy regulatory context. US Solar suggests clarifying that this 2-point siting tiebreaker be awarded (a) for Traditional Community Solar applications in Group A if there is no previous REC-awarded Traditional Community Solar project in the same county, and (b) for Traditional Community Solar applications in Group B if there is no previous REC-awarded Traditional Community Solar project in the same township. US Solar also requests clarification that Traditional Community Solar applications in Group B can receive the same geographic preference points for being located within a municipality as they can for being located in the neighboring township (i.e., just outside of the municipality). US Solar Obj. at 3-4.

3. Joint Solar Parties' Position

The Joint Solar Parties appreciate that the IPA follows the statutory requirement that projects are selected on a first-come, first-served basis. However, the JSPs have two primary objections to the proposed project selection process: 1) ambiguities over how the IPA will apply the same day tie-breakers and 2) the secondary project selection criteria must be project maturity. The Joint Solar Parties are concerned that by ignoring project maturity and instead using non-maturity tiebreakers for projects submitted on the same day that the project selection approach will cause chaos in the interconnection queue and lead to more speculative projects as well as harm predictability of selection. JSPs Obj. at 26-27.

Section 1-75(c)(1)(K) requires that the IPA "establish program eligibility requirements that ensure that projects that enter the program are sufficiently mature to indicate a demonstrable path to completion." Securing a place in the interconnection queue makes a project much more likely to develop because it reduces the risk on interconnection costs due to changing circumstances from systems ahead in the queue. JSPs Obj. at 29-30.

Upon review of the proposed scoring system the IPA proposes to use, if too many systems apply on a single day than capacity remains available, none of the attributes appear to the Joint Solar Parties to address project maturity. Importantly, the points for the date of the first ICA are not related to project maturity because a former signed ICA that is no longer in effect has no bearing on the project's potential interconnection costs if it reapplied today. Instead, it appears to be a way to favor original waitlisted projects. While the Joint Solar Parties do not take a position on whether to further favor waitlisted projects, favoring original waitlisted projects has nothing to do with maturity. JSPs Obj. at 30.

To the extent that the IPA uses a scoring system, the Joint Solar Parties argue that it should be secondary to project maturity criteria. Otherwise, a scored group of projects

risks replaying some of the interconnection issues from the initial lottery while also creating the risk for an increased number of projects being selected and then dropping out 2-3 years later, delaying the RECs that ratepayers' RPS charges paid for. Furthermore, the Joint Solar Parties are concerned that the increased uncertainty and lack of clarity over selection from a larger volume of less certain projects will increase development risk and thus development costs. JSPs Obj. at 30.

The Joint Solar Parties note that the ABP structure after P.A. 102-0662 has changed from continuously opening blocks to annual blocks. However, Section 1-75(c)(1)(K) requires that the ABP include "the terms and conditions for securing a spot on a waitlist once the block is fully committed or reserved." 20 ILCS 3855/1-75(c)(1)(K). Furthermore, "the waitlist of projects in a given year will carry over to apply to the subsequent year when another block is opened." *Id.* The statute contemplates a pathway to securing an identified spot on the waitlist so that a project on the waitlist knows its specific location. Combined with the Traditional Community Solar-specific "first-come, first-served basis" requirement (20 ILCS 3855/1-75(c)(1)(K)(iii)(1)), the JSPs opine that there should be a continuously open waitlist that allows an applicant to lock in their position on the day they apply. JSPs Obj. at 27-28. The Joint Solar Parties appreciate that the IPA has confirmed that the community solar waitlist is intended to be continuously open once the program reopens on November 1, 2022. JSP Rep. at 27.

Conversely, the Joint Solar Parties strongly oppose the Joint NGOs' proposal to re-score waitlisted projects every time a new block opens. This would reverse the IPA's clarification regarding a continuously open waitlist. As the Joint NGOs acknowledge, such an approach is in direct contravention to the statutory requirement that projects be selected on a first-come/first served basis. See 20 ILCS 3855/1-75(c)(1)(K)(iii)(1). In addition, it creates uncertainty about a project's status because its position is always vulnerable to new program applicants, creating a lack of predictability. However, the Joint Solar Parties agree with the Joint NGOs that if implemented without an effective developer cap, a first-come/first-served program could be monopolized by early movers. The Joint Solar Parties recommend that the IPA take stakeholder feedback in anticipation of implementing a developer cap (including how capped projects are included on waitlists) in advance of the new Community Solar block proposed to open on November 1, 2022. JSP Rep. at 27-28.

The Joint Solar Parties explain that there should also be a developer cap to prevent a single or small handful of entities from monopolizing capacity in the Traditional Community Solar block. The Joint Solar Parties believe that the optimal developer cap that is consistent with the statutory requirement that the ABP be "designed to provide for the steady, predictable, and sustainable growth of new solar photovoltaic development in Illinois" would be best addressed after stakeholder comment so all developer voices can be heard, rather than locking in a particular approach in this LTRRPP. JSPs Obj. at 28.

Without agreeing that a point system to meet policy goals is advisable, the Joint Solar Parties note their opposition to some of the scoring criteria. First, the Joint Solar Parties oppose using Conservation Opportunity Area as a points deduction. While the Joint Solar Parties appreciate the spirit of benefitting the built environment by penalizing competing areas, based on a visual inspection of the Illinois Department of Natural Resources' online map, the Joint Solar Parties note there is substantial overlap between

Conservation Opportunity Areas and certain Environmental Justice areas. In addition, design of the solar system can mitigate habitat impacts - in many cases better than row crops or other current uses of the same land. JSPs Obj. at 30-31.

The IPA disputes this, claiming “The overlap is limited and should not inhibit development within Environmental Justice Communities.” IPA Resp. at 43-44. The Joint Solar Parties believe a review of publicly available information demonstrates that the overlap is not, in fact, limited. JSP Rep. at 28. While the JSPs agree that Conservation Opportunity Areas certainly do include ecologically sensitive areas, millions of acres of Conservation Opportunity Areas are currently used for row crops. Using these croplands for solar energy (especially when planted with pollinator friendly habitat) would carry a far smaller environmental impact than annual planting, harvesting, and application of pesticides and herbicides to corn or beans, result in healthier soil, less runoff, and provide new habitat for threatened and endangered gamebirds, songbirds, and pollinating insects. JSP Rep. at 29.

The legislative findings in Section 1-5 of the IPA Act include a finding that brownfield solar will “help return blighted or contaminated land to productive use while enhancing public health and the well-being of Illinois residents, including those in environmental justice communities.” 20 ILCS 3855/1-5. Conservation Opportunity Areas were created under Illinois 2005 Wildlife Action Plan to address the particular needs of wildlife that are declining so that populations can be stabilized and then increased. Inhibiting solar development in these areas does not serve statutory goals and can actually diminish opportunities to preserve wildlife. JSP Rep. at 30-31.

The Joint Solar Parties believe the Conservation Opportunity Areas disincentive does more harm than good and should be removed. However, if the Commission does not remove the loss of points for developing in a Conservation Opportunity Area, the Conservation Opportunity Area subtractor should not apply if the project also meets one of the three following criteria: 1) commits to pollinator-friendly habitat; 2) is located in an Environmental Justice community or in a Restore, Reinvest, Renew funding area (“R3 area”); or 3) is located on a brownfield, contaminated land, or disturbed land. JSP Rep. at 31.

In addition, the Joint Solar Parties recommend a modification to the section awarding points for being the first system in a particular geographic location. The Joint Solar Parties appreciate the IPA’s desire to encourage greater geographic diversity in the location of programs, however, this section cannot practically serve as a market signal to drive geographically diverse project siting without accurate and up-to-date information regarding where existing systems are sited. If the Commission maintains this section of the scoring criteria, it should require the IPA to provide a regularly updated list of projects which have been approved by the Commission for a REC contract including county and township locations for each. Presently, no such repository is available to the best of the Joint Solar Parties’ knowledge. However, disclosure of locations alone will not bring stability to the market or properly incent geographic diversity. The IPA’s proposal uses a constantly moving target that is incongruous with solar development cycles. JSP Rep. at 31-32.

A small but effective change to further address the issue is to make the point apply at the time of the new system's application, not its selection or Commission approval. This small change would mitigate the uncertainty of developing a project toward an uncertain, opaque target that is subject to change after the project has already been submitted. JSP Rep. at 32.

In addition, the Joint Solar Parties do not support the substantial bonus for projects that took part in the initial lottery (through the proxy of points for the earliest original ICAs). Initial lottery projects are already favored by the Section 1-75(c)(1)(G)(iv)(3) waitlist capacity application process. The JSPs opine that there is nothing inherently more meritorious or mature about these early-developed projects. JSPs Obj. at 30-31.

Furthermore, the Joint Solar Parties note that the scoring criteria categories in Section 1.a. (sited on disturbed or contaminated land) and 1.b. (sited on a brownfield) are duplicative. Section 1.a provides 2 points for a project sited on "contaminated land as defined by the United States Environmental Protection Agency," while 1.b provides 2 points for a project "sited on a brownfield." Given brownfields are a category of contaminated land as defined by the U.S. Environmental Protection Agency, these two categories are really one and the same, yet a project sited on a brownfield could erroneously be awarded 4 points under the current rules (2 point for being on contaminated land under 1.a, and another two points for being on a brownfield under 1.b). The Joint Solar Parties recommend that section 1.b of the scoring criteria be combined with section 1.a to correct this error. JSP Rep. at 32-33.

If the Commission does not adopt the Joint Solar Parties' primary recommendation to make project maturity the primary tiebreaker to projects submitted on the same day, the Joint Solar Parties urge the Commission to adopt the Joint Solar Parties' alternative compromise scoring approach to interconnection. In addition, the Commission should reject the Joint NGOs' rescoring proposal. Regardless, the Commission should adopt the position of the IPA, Staff, and the Joint Solar Parties that the community solar waitlist be continuously open, as further defined by the IPA in its Response Comments. JSP Rep. at 33.

Rather than heavily modify the LTRRPP proposal that does not take into account project maturity and appears to not have continuously open waitlists, the Joint Solar Parties propose an alternative approach. The JSPs assert that the IPA should open waitlists for Traditional Community Solar block on August 1, 2022. In the alternative, if the IPA identifies barriers to opening the block, a waitlist should open as soon as practicable after August 1, 2022 if the block opening is delayed. Opening the program to new applications, whether by opening the block itself (as the Joint Solar Parties prefer) or by opening a waitlist and then a block (if the IPA believes it is necessary) would alleviate pressure on the program from additional time leading to more applicants, while still allowing the IPA additional time after the anticipated July 19, 2022 Order in this docket to make changes. JSPs Obj. at 31-32.

To the extent that on a particular day, there are applications that exceed remaining capacity, the IPA should extract the date of the site control document, the effective date of the ICA, and the date of the land-use permit (if required) and use the latest of those three dates to set the project maturity date. To the extent that a tie remains (i.e. two or

more projects have the same project maturity date), the Joint Solar Parties recommend using the effective date of the ICA (as a proxy for queue position), followed by a random selection between any remaining ties. The Joint Solar Parties recommend that implementing desirable policies should be done through monetary (such as adders) or non-monetary incentives to Approved Vendors. JSPs Obj. at 32.

Not only does this approach reflect the clear statutory requirement to select projects on a first-come/first-served basis, it expands on the requirement for a temporal selection system using objective and knowable dates. The Joint Solar Parties' approach would effectively align the Traditional Community Solar project selection process with the utilities' interconnection queue process and bring greater transparency and predictability to a system that has become highly chaotic in the past when project selection was divorced from interconnection. JSPs Obj. at 32.

The Joint Solar Parties also propose a compromise approach that aims to work within the IPA's existing scoring criteria to strongly incentivize (but no longer require) an ICA. To that end, the Joint Solar Parties propose as follows:

- Eliminate all points assigned to systems based on original ICA date, because the date of an original ICA (unless that agreement is still active) provides no indicia of project maturity as the grid around it may have changed dramatically.
- Amend the interconnection category to create "eligibility requirements that ensure that projects that enter the program are sufficiently mature to indicate a demonstrable path to completion" as directed by statute. See 20 ILCS 3855/1-75(c)(1)(K). The Plan should be amended to award points for the following, which are intended to be additive and to have a maximum score of 8:
 - o Five points for a signed, valid ICA.
 - o Two additional points for having a top-two queue position on a substation on the date of the application among community solar projects.
 - o One additional (fractional) point for having a signed ICA prior to the date of the first community solar block opening (expected November 1, 2022). This single fractional score could be essential for breaking ties.

JSP Rep. at 24-25.

To make this system most effective, the JSPs aver that the Commission must require a minimum score for all projects applying to the program. Because the block will be open for a full year (even if capacity is unavailable at that time), it is inevitable that there will be many days when only one project applies to the program waitlist. To prevent speculative, immature assets from taking up waitlist space on those days, the Commission should direct the IPA to implement a threshold minimum score of five points to enter the program queue. This would require the Program Administrator to score every project that applies, not just the first day and those that are tied. JSP Rep. at 26.

The Commission should reject the IPA’s proposal that a selected project which is awarded points “that includes a commitment” will see “termination of the contract or product order (and forfeiture of associated collateral)” if the project fails to meet and maintain that commitment. While the Joint Solar Parties fully support holding applicants to their pledges, losing the REC contract entirely is a draconian penalty that will make projects virtually unfinanceable. For instance, a project that pledges to plant pollinator-friendly habitat on a site must then complete the Illinois Solar Site Pollinator Scorecard and earn at least 70 points annually to be deemed “pollinator friendly.” If for some unforeseen reason, the site fails to meet that threshold in year seven of the contract, the project would lose its entire revenue stream and become a stranded asset. Lenders will not provide capital to developers with risks of this magnitude (or will charge untenable risk premiums not reflected in the REC Price Model). A better approach would be to draw on the project’s REC Collateral until such time that the project is within compliance. The Joint Solar Parties are open to other approaches as well. JSP Rep. at 33-34.

4. Summit Ridge’s Position

Summit Ridge states that the Built Environment category will be enhanced if developed land is explicitly included as part of sub-category 1a. Based on this recommendation, Summit Ridge proposes the following addition to the scoring criteria language: Site on disturbed or developed land as defined by the United States Ecological Survey or contaminated lands as defined by the United States Environmental Protection Agency (Add 2 points). SRE Resp. at 1.

5. LVEJO’s Position

While LVEJO appreciates the JSPs’ concerns that less mature projects may be prone to a higher failure rate, LVEJO opposes the maturity-centric tie-breaker system proposed by the JSPs. At its core, the ABP is “designed to provide for the steady, predictable, and sustainable growth of new solar photovoltaic development in Illinois.” To this end, the ABP awards REC purchase agreements to new projects developed in Illinois. LVEJO believes that the currently proposed point system sufficiently fulfills the statutorily imposed first-come, first-serve project-selection criteria while aligning the project selection process with the other policy goals of the ABP. LVEJO Resp. at 12.

LVEJO supports the JSPs’ objection calling for a developer cap in the Traditional Community Solar block of the ABP. JSPs Obj. at 25. A cap would be designed to prevent a single or small group of developers from monopolizing the capacity in that block. LVEJO has expressed similar concerns in past comment periods, particularly for that block and the EEC block, and it supports implementation of a cap. LVEJO Resp. at 7.

6. Staff’s Position

The JSPs object to the Plan for not selecting solar projects submitting applications on the same day based upon project maturity in the event of a tie. Staff notes that the JSPs’ argument is tied to its position that a signed ICA must be submitted with applications. Staff does not support that objection and therefore, does not support this objection of the JSPs. Staff Resp. at 22.

Also, the JSPs object to the Plan's use of a scoring system based upon policy goals instead of product maturity to choose between applications submitted on the same

day, recommending instead that policy goals be met through adders. Staff does not support the JSPs' objection. Selecting projects based upon policy objectives without inflating project prices is a more cost-effective approach to project selection in this instance. Staff Resp. at 22.

Staff notes that the JSPs also object to the Plan for not being clear that Traditional Community Solar has a continuous wait list. Staff supported the JSPs' objection. Staff Rep. at 33. The IPA's Response Comments addressed the continuous open wait list issue. The IPA states that it agrees with the JSPs "that for projects submitted after the first day, applications will be ranked-ordered based on application date rather than based on the Plan's tiebreaking criteria." IPA Resp. at 45. The IPA further explains that if two projects were submitted on the same day after the first day, the IPA would utilize its scoring criteria to "break a tie between [] two projects submitted equivalently 'first.'" *Id.* The Joint NGOs, however, want the IPA to re-rank projects on the first day of each delivery year according to the IPA's scoring system. Staff Rep. at 33.

The Joint NGOs' argument for a re-ranking is not consistent with the law in Staff's opinion and should be rejected. The law is clear that projects are to be selected on first-come, first serve basis (20 ILCS 3855/1-75(c)(1)(K)(iii)(1)) and the IPA's ranking criteria is only used in one of two instances. First on Day 1 to break ties and second, on any subsequent day when one or more projects submit their application on the same day. Staff Rep. at 33.

7. IPA's Position

As is well documented, the IPA states the January 2019 launch of the ABP featured approximately eight times more community solar project applications than program capacity available over the initial two-week application window. Applicant projects were selected for REC delivery contracts through the random selection process authorized by the Commission in Docket No. 17-0838, and unselected projects were placed on ordinal waitlists awaiting selection once additional program capacity became available. As project applications required ICAs and non-ministerial permits as markers of project readiness, local governments and utility interconnection staff were forced to process many times more permitting and interconnection requests than projects actually developed. IPA Resp. at 39.

For future Traditional Community Solar block openings, Section 1-75(c)(1)(K)(iii)(1) of the IPA Act specifies that "the Agency shall select projects on a first-come, first-serve basis, however the Agency may suggest additional methods to prioritize projects that are submitted at the same time." This raises the question of what "first" means. The Long-Term Plan proposes that "submitted at the same time" be considered on a first day basis rather than the exact second (or nano-second) that a project application is submitted at program opening, and no party objected to the Agency considering all projects submitted on Day 1 equivalently "first" under the law. IPA Resp. at 39-40.

At issue, then, is what happens should applications for Traditional Community Solar projects submitted on the first day of block opening exceed block capacity. Section 1-75(c)(1)(K)(iii) allows the Agency to "suggest additional methods" for prioritizing projects "submitted at the same time," and Section 7.4.3 of the Plan outlines the Agency's proposal

for breaking those ties. The IPA proposes to utilize a scoring system that prioritizes qualitative aspects of individual projects in determining which equivalently “first” projects should receive a REC delivery contract award. This scoring system focuses on objectives outlined in declaratory paragraphs or other statutory language found in the IPA Act, or otherwise supporting comparable policy considerations. Thus, points are awarded based on the proposed project’s built environment attributes, siting attributes, and level of commitment to using equity eligible contractors (with maximum points for the applicant itself being an equity eligible contractor). IPA Resp. at 40.

Additionally, the scoring system awards higher points to projects with earlier original ICA dates. While the IPA is reluctant to decide between competing applications using criteria that has no express support in statute and would not demonstrate progress toward an important policy objective, utilizing the initial ICA date provides a means for avoiding multiple projects having the same score. Projects would be ranked by original ICA effective date (say, from 1-100) to provide a fractionally different score for each. IPA Resp. at 40-41.

This underscores the primary difference between the IPA’s proposal for distinguishing between equivalently “first” projects and that of the Joint Solar Parties. Both proposals ensure that all applicant projects can be rank-ordered for selection and provide developers with visibility into how their project may fare under rank-ordering criteria. But while the IPA’s proposal accommodates important policy objectives while ensuring that projects can be transparently rank-ordered, the JSPs’ proposal only seeks to rank-order projects through “extract[ing] the date of the site control document, the effective date of the ICA, and the date of the land-use permit (if required) and use the latest of those three dates to set the project maturity date.” In the JSPs’ eyes, having the earliest such date means that the project is most “mature” and thus more deserving of a REC delivery contract award. IPA Resp. at 41-42.

The IPA believes that the JSPs’ proposal suffers from significant flaws. First, simply having an earlier date of site control, ICA, or permitting does not make a project more “mature” or otherwise likely to be developed. From the IPA’s observation, community solar project developers generally take only those development steps required for successful application into the program—and then cease taking additional steps until such time as that project receives a REC delivery contract award. Thus, a project having obtained site control in 2016 is no more “mature” than a project having done so in 2018; the developer just held a land lease for longer. Similarly, a project that received an ICA six months ago is no more “mature” than one that received its agreement just last week. While one project may have interconnection queue priority over another, each has yet to pay associated interconnection costs, construct the facility, and acquire subscribers. As each proposed project is equivalently “mature” in any meaningful sense, the IPA argues that sorting projects based on the earlier of these dates serves no useful end beyond clarity in selection likelihood. IPA Resp. at 42.

Second, even if earlier dates could serve as a proxy for project “maturity,” the IPA opines that a more mature project is not necessarily a project more worthy of a REC delivery contract award. No passage within the IPA Act demonstrates a preference for projects that obtained site control or permitting earlier than other projects. No public policy concern is addressed through awarding REC delivery contracts to more “mature” projects

first. While the JSPs attempt to argue that increased “maturity” may correspond with reduced development risk, the development risk facing community solar projects receiving REC delivery contracts appears to be small: only 7.2% of community solar projects initially awarded REC delivery contracts failed to develop, and that pool of projects was drawn from a purely random selection. IPA Resp. at 42-43.

The IPA concedes that its approach works most effectively when coupled with disincentives for securing a REC delivery contract and not successfully developing that project. On this point, the IPA explains that a developer risks losing up to 5% of the contract value in collateral, which can be hundreds of thousands of dollars, and no party has argued that penalty to be insufficient. IPA Rep. at 51-52.

The IPA notes that the JSPs also complain regarding the “bonus for projects that took part in the initial lottery” through reliance on the original ICA date, the Agency generally agrees with the JSPs that sorting projects based on earlier interconnection queue entry is indeed “not inherently more meritorious.” Use of that criteria is based on pragmatism more so than merit, and the Agency is open to other alternatives which may similarly sort project applications through unique, fractional scores. IPA Resp. at 43-44.

The Joint Solar Parties request that the Traditional Community Solar block open on August 1, 2022, rather than November 1, 2022, as proposed in the Plan. Section 1-75(c)(1)(K)(iii) only calls for opening the Traditional Community Solar project category “[s]tarting in the third delivery year after the effective date” of P.A. 102-0662 “or earlier if the Agency determines there is additional capacity needed for to meet previous delivery year requirements.” This opening date being less than 14 months after P.A. 102-0662’s passage is already a massive concession to community solar project developers, and the Agency unable to go beyond this. Opening later in 2022 is a pragmatic necessity given the complexity of applying new qualitative criteria to project applications, as it allows the Agency to prepare new project application interfaces, develop guidelines for project review and scoring, and develop new contract instruments reflecting consequences for non-compliance with selection criteria. A later opening also allows developers to secure site control and permitting for projects faring well under the Agency’s project selection criteria (such as brownfield site projects and projects in Environmental Justice Communities), thus hopefully maximizing the number of applicant projects featuring built environment, siting, and other attributes prioritized in project selection. IPA Resp. at 44-45.

The IPA notes that certain aspects of the IPA’s proposed scoring system do require clarification: first, for projects that did not maintain their spot on an ordinal waitlist created as part of the 2019 lottery process (for instance, due to the loss of site control or failure to obtain permitting requirements), those projects would receive zero points for the interconnection application effective date, as those projects have effectively withdrawn themselves from the program. Second, with respect to prospective projects that have changed since originally receiving an ICA, those projects will be considered the “same” project that initially applied for interconnection so long as the project features the same address, even if the proposed project changed ownership or resized. IPA Rep. at 27.

Over time, the IPA explains that other questions will likely emerge requiring clarification. This underscores the need for opening the Traditional Community Solar

block later than other program categories for the 2022-2023 annual block, as outlined in Section 7.3.4. The IPA has proposed November 1, 2022 as the earliest feasible Traditional Community Solar block opening date, allowing enough time to work through stakeholder processes and build out the architecture for receiving and scoring project applications. IPA Rep. at 27.

While generally supporting the IPA's tie-breaking scoring, the Joint NGOs suggest that the Commission require the IPA to carry over its waitlist and not require waitlisted projects to reapply, but to re-rank waitlisted projects along with any new projects submitted on the first day of each delivery year, according to the IPA's scoring system. The Agency agrees that projects that submitted a project application during the prior program year need not reapply on Day 1 of the subsequent year, although project application elements may require confirmation or update. Regarding "re-ranking waitlisted projects along with any new projects submitted on the first day," the IPA believes this is not the strongest reading of the law. Section 1-75(c)(1)(K)(iii) requires that Traditional Community Solar projects be selected on a "first-come, first-serve basis"—resulting in an ordinal waitlist established by program application date. Elsewhere, Section 1-75(c)(1)(K) requires that "the waitlist of projects in a given year will carry over to apply to the subsequent year when another block is opened." These two clauses together offer preference to waitlisted projects upon the next program year's block opening as projects that applied "first." IPA Rep. at 27-28.

The Joint NGOs caution that carrying over waitlist preferences to a subsequent delivery year may penalize projects that take longer to develop and apply, which may nonetheless have more characteristics that P.A. 102-0662 seeks to encourage, such as participation by Equity-Eligible Contractors or brownfield siting, with earlier-applying projects serving to unintentionally block projects that more completely meet P.A. 102-0662's various policy goals. The IPA generally agrees. The question for the Commission may be whether the Joint NGOs' policy-driven argument can be supported through a more flexible reading of Section 1-75(c)(1)(K)'s requirements; the IPA will faithfully implement whichever approach the Commission approves. IPA Rep. at 28.

The IPA notes that the JSPs seek clarification that for projects submitted after the first day, applications will be rank-ordered based on application date rather than based on the Plan's tie-breaking criteria. The Agency agrees. Section 1-75(c)(1)(K)(iii)(1) requires that "the Agency shall select projects on a first-come, first-serve basis," with the Agency's selection criteria serving only as a method "to prioritize projects that are submitted at the same time." Thus, a project submitted on Day 3 must be prioritized over a project submitted on Day 30—even if the project submitted on Day 30 received the maximum score under the Agency's scoring criteria—and waitlists will reflect that prioritization. However, if both projects were submitted on Day 3, then the Agency would utilize its scoring criteria to break a tie between these two projects submitted equivalently "first." IPA Resp. at 45.

The IPA notes that Joint Solar Parties also complain that under the Built Environment scoring, points are deducted for development in Conservation Opportunity Areas, noting the overlap between Conservation Opportunity Areas and Environmental Justice Communities (for which points are awarded in Siting). The IPA states that the overlap is limited and should not inhibit development within Environmental Justice

Communities. The IPA believes scoring in a manner which penalizes using Conservation Opportunity Area land within Environmental Justice Communities provides an appropriate disincentive back to developers and need not be adjusted. IPA Resp. at 43-44.

The IPA notes that US Solar argues that the Built Environment scoring criteria for projects that commit to ag/dual use “should include a biennial reporting requirement to demonstrate compliance with this opt-in commitment.” The IPA supports biennial reporting at minimum but notes that not all specifics around ongoing reporting obligations, requirements for a successful application, and other implementation details were included in the LTRRPP. Additional implementation details will be developed after Plan approval. IPA Resp. at 45-46.

The IPA notes that US Solar also seeks for the siting preference for community solar projects located in a county or township that does not already have an ABP-participating community solar project be expanded to include each township and municipality in ComEd’s service territory. The Agency explains that its intent in distinguishing between counties and townships was to draw a population-based distinction between less dense counties versus more urban and suburban counties (for which a single community solar project, on a pro rata basis, represents a much less significant share of local economic activity). Thus, the Plan allows for those points to apply to a project “sited in a county . . . that does not currently have a community solar project that was approved by the Commission for a REC contract under the Adjustable Block Program at the time of application”—or, in the case of only Cook, DuPage, Kane, Lake, McHenry or Will Counties (which are more densely populated, and for which a community solar project represents a much smaller share of overall population and economic activity), that assessment is made at the township level. IPA Resp. at 46.

To the extent that US Solar is merely seeking clarification around how that preference would be applied, the Agency hopes that the above explanation provides that clarification. To the extent that US Solar is seeking for that preference to be applied differently, and instead have a township distinction applied across the entirety of Group B (a geographical footprint that generally corresponds with the ComEd service territory), the IPA disagrees. Outside of the Chicagoland area, the IPA believes that the considerations that support drawing a distinction at the county level rather than the township level throughout Group A apply with equal force to the remainder of Group B area, as the remainder of Group B is generally more rural. If the consequence of applying this adder to townships within Cook County and collar counties is to encourage applications from sites located in those counties (as more potential sites would then be eligible for favorable treatment in project selection within those counties), then the Agency believes this is a positive public policy outcome. Siting more community solar projects near the communities they serve addresses a common critique of community solar market development in Illinois: that projects are devoid of community participation and disconnected from subscribers. IPA Resp. at 46-47.

Lastly, the IPA notes that Summit Ridge seeks to add the phrase “or developed” to “disturbed land” under the Built Environment scoring criteria. While incenting Traditional Community Solar development on already-developed land supports similar objectives to those achieved through other Built Environment scoring criteria, with no supporting analysis other than a conclusory statement that the Built Environment category

“will be enhanced” by this addition, the IPA opines that the record before the Commission is insufficient for supporting this change. IPA Rep. at 28-29.

8. Commission Analysis and Conclusion

The IPA has proposed November 1, 2022 as the earliest feasible Traditional Community Solar block opening date to allow enough time to work through stakeholder processes and build out the architecture for receiving and scoring project applications. IPA Rep. at 27. The Commission finds this to be a practical solution given the various issues that the IPA proposes to continue discussing with stakeholders. It is reasonable and adopted.

The Commission does not adopt the proposal of the Joint Solar Parties to require a signed ICA for the Traditional Community Solar block. The Commission agrees with the IPA that a signed ICA is not a useful proxy for project maturity. This is further discussed below in Section 7.9.1 regarding technical system requirements. Rather, the Commission agrees with the IPA that projects should be chosen on a first-come, first-served basis, but if submitted on the same day, the scoring process proposed by the IPA appropriately weighs projects based on policy goals contained in P.A. 102-0662.

The Commission notes that the Joint Solar Parties propose that rather than ranking projects with the policy-based tie-breaking system proposed by the IPA, the IPA should rank projects based on system readiness. While the JSPs argue that increased maturity may correspond with reduced development risk, the Commission finds compelling the IPA’s statement that the development risk facing community solar projects receiving REC delivery contracts appears to be small and that only 7.2% of community solar projects initially awarded REC delivery contracts failed to develop. IPA Resp. at 42-43. Also compelling is the IPA’s observation that community solar project developers generally take only those development steps required for successful application into the program and then cease taking additional steps until such time as the project receives a REC delivery contract award. For these reasons, the Commission does not adopt the JSPs’ proposal.

Although the Commission does not adopt the JSPs’ proposal to require a currently valid, executed ICA as a participation requirement for the Traditional Community Solar block for the reasons discussed, the Commission recognizes that obtaining a signed ICA remains a critical step in the project development process. The Commission also recognizes that, with its recent adoption of its updated interconnection procedures in Docket No. 20-0700, a project developer will now be required to pay a deposit equal to 100% of their estimated upgrade costs within 15 business days of signing an ICA, which makes the ICA a more immediately meaningful financial commitment for project developers. Therefore, the Commission finds that having a currently valid, executed ICA should be encouraged and included as one of the scoring criteria in the IPA’s waitlist scoring system, as the JSPs propose. The Commission directs the IPA to include this scoring criterion within its interconnection scoring category. The Commission does not make a finding on the appropriate number of points to assign to this criterion, and leaves that decision to the IPA, in consultation with stakeholders. The Commission also directs the IPA to consider and discuss with stakeholders the inclusion of the JSPs’ two additional interconnection scoring criteria, the removal of the currently proposed interconnection

criteria, and any other interconnection-related criteria that the IPA believes warrant consideration.

The Commission finds that the IPA's proposed tie-breaker scorecard appropriately aligns the waitlist with the policy goals in P.A. 102-0662, with the three modifications to the scoring criteria discussed in this section related to interconnection, projects sited in Conservation Opportunity Areas, and projects sited on rooftops or other structures. In addition, the Commission agrees that a threshold point requirement to enter the waitlist makes sense and will help ensure that only projects that meet some minimum requirements are on the waitlist. The Commission does not specify a numerical points threshold for the IPA to adopt, however the Commission requires that the points threshold be above the number of points assigned to having a currently valid, executed ICA, such that a project would have to meet at least one other scoring criterion (if not multiple other criteria) in order to enter the program queue. Similarly, the Commission agrees that adoption of a developer cap, which will also help ensure a fair ranking of the waitlist, is appropriate. Both these proposals, however, are not described in sufficient detail by the parties. Indeed, it appears that all agree the specifics can be worked out in the stakeholder process; the Commission accepts this proposal and directs the IPA to continue stakeholder discussions to finalize the waitlist requirements with the modifications adopted herein.

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. The Joint NGOs, however, seek to have the IPA re-rank the list with each new annual opening of the block to align the waitlisted projects with the policy goals contained in the IPA's tie-breaker categories. Although the Commission agrees with the IPA that there is merit to this idea, Section 1-75(c)(1)(K)(iii) of the IPA Act requires that Traditional Community Solar projects be selected on a "first-come, first-serve basis." Elsewhere, Section 1-75(c)(1)(K) requires that "the waitlist of projects in a given year will carry over to apply to the subsequent year when another block is opened." The re-ranking proposed by the Joint NGOs conflicts with these two provisions of the IPA Act.

Next, the Commission notes the Joint Solar Parties' belief that the Conservation Opportunity Areas disincentive does more harm than good and should be removed. The IPA, however, disagrees with the JSPs' assertion regarding the overlap of maps. The Commission agrees with the IPA on this point but finds merit in the JSPs' proposal from Reply Comments. The JSPs request that if the Commission does not remove the loss of points for developing in a Conservation Opportunity Areas, the Conservation Opportunity Areas subtractor should not apply if the project also meets one of the three following criteria: 1) commits to pollinator-friendly habitat; 2) is located in an Environmental Justice community or R3 area; or 3) is located on a brownfield, contaminated land, or disturbed land. The Commission shares the JSPs' interest in ensuring that projects in Environmental Justice communities and R3 areas, as well as those located on brownfields, contaminated land, or disturbed land, are not unintentionally discouraged by the Conservation Opportunity Areas subtractor. That said, exempting any projects that utilize pollinator-friendly habitat could effectively nullify the usefulness of the subtractor in preserving sensitive land. The Commission therefore accepts a modified version of the JSPs' proposal wherein the Conservation Opportunity Areas subtractor will not apply if

the project also meets both of the following criteria: 1) commits to pollinator-friendly habitat; and 2) is located in an Environmental Justice community or R3 area, and/or on a brownfield, contaminated land, or disturbed land.

With respect to US Solar's objection regarding Ag/dual use, the Commission notes that the IPA seems to agree with US Solar's request for biennial reporting. The IPA also seems to suggest that US Solar's objection is too granular and the specific implementation details will be further developed after the Plan is approved. The Commission agrees with this process and adopts the IPA's position.

US Solar also sought clarification regarding the IPA's tie-breaker preference for new Traditional Community Solar projects sited in a county or township that does not contain other approved community solar projects. The Commission accepts the IPA's explanation in its Response Comments and the Commission notes that US Solar did not file Reply Comments on this issue. However, the Commission sees that the JSPs assert that without more information, it is not possible for applicants to meet this criteria. It appears that the IPA has published or will be publishing the addresses of all community solar projects receiving REC delivery contract awards, thus allaying the JSPs' concern.

The Commission notes that Summit Ridge seeks to add the phrase "or developed" to "disturbed land" under the Built Environment scoring criteria, with both "developed land" and "disturbed land" being defined by the United States Geological Survey ("USGS"). The Commission recognizes the value of encouraging solar on rooftops and other existing structures from a land conservation perspective. Furthermore, the Commission notes that explicitly incorporating projects on rooftops and other structures would be consistent with the policy goals of P.A. 102-0662, which underlies the IPA's rationale for all of its scoring criteria. Therefore, although the Commission acknowledges the IPA's concern that the record is limited on this issue, the Commission adopts a modified version of Summit Ridge's proposal. The Commission finds the definition of "developed land" employed by the USGS to be overly broad for these purposes. The Commission instead directs the IPA to incorporate a separate category of projects "sited on rooftops and other structures" into its Built Environment category.

In Reply Comments, both the IPA and the JSPs discuss penalties for the failure of applicants to uphold the commitments that apply to this REC scoring tie-breaker. Disciplinary action is discussed further in Section 9.3.3 below.

D. Section 7.4.4 Public Schools

1. US Solar's Position

In its 2022 Plan, the IPA provided clarification regarding the proposed compliance requirements for a community solar project to qualify for REC capacity under the new Public Schools category. While this additional detail is helpful, US Solar states that it also raises new, more-detailed concerns that should be addressed in this section of the 2022 Plan. First, on information and belief, public schools typically contract for community solar subscriptions at the district level (not at the individual school level). Also, due to contractual practices and because the school district typically receives and pays for each school's utility bills, the district would be the entity that receives the resulting subscriber bill credits. US Solar Obj. at 5.

US Solar is also concerned that the new language would appear to establish a 20-year subscription mandate on any public schools that may be interested in hosting a community solar project on site. Although requiring participation during the first few years seems reasonable, the IPA should consider the potential downside to the subscriber of establishing a regulatory rule that effectively prohibits the subscriber from transferring, exiting, or downsizing its subscription agreement at any point during the 20-year project term, even if the school were to close for an extended period of time (reducing its electricity use to near zero) or move to another location. US Solar Obj. at 5-6.

2. Staff's Position

Staff supports US Solar's objection seeking clarification to the Plan that schools can participate at the district level. Staff Resp. at 24. Staff agrees with the steps the IPA has proposed to address US Solar's Objections by allowing flexibility in the anchor tenant requirement and requests for waivers of subscription requirements. Staff opines that the IPA's steps reflect reasonable accommodations in response to valid concerns regarding the Public Schools category. Staff Rep. at 37.

In its BOE, Staff states that it agrees with the JSPs that projects located on school or school district-owned land adjacent to anchor subscriber public schools are eligible. Staff further agrees with the JSPs that projects located on school district-owned land that is not adjacent to the subscriber school are eligible. Staff BOE at 13. In its RBOE, Staff adds that both such projects should be eligible, because school districts only exist in connection with a school, and as long as the project is located on school district land, the project is in effect "installed at" a public school. Staff RBOE at 9-10.

3. Joint Solar Parties' Position

The Joint Solar Parties appreciate the IPA's clarifications in response to US Solar regarding Public School Block requirements for community solar. The Joint Solar parties, however, recommend further clarification to siting requirements for community solar projects within the Public Schools Category. The JSPs note that Section 7.4.4 of the LTRRPP does not currently provide guidelines for determining the eligibility of projects that are located on school or school district-owned land adjacent to corresponding anchor subscriber public schools. The Joint Solar Parties believe that such projects should, generally speaking, be eligible. The Joint Solar Parties further request that the IPA provide guidance as to whether a community solar project serving a school can be located on school district-owned land that is not adjacent to the school subscriber. The Joint Solar Parties, generally speaking, believe that should be allowed. JSP Rep. at 41.

In its RBOE, the JSPs did not disagree with the IPA's position, but clarified that the adjacent property should be used for school purposes, not school-related activities. JSP RBOE at 3.

4. IPA's Position

The Agency appreciates the concerns raised by US Solar and believes that in order to ensure success of the implementation of the Public Schools category, reasonable accommodations should be made for the requirements around the anchor tenant. If, for example, a public school is unable to sign a subscription agreement due to the district's contractual practices, not only would that particular school be unable to avail themselves

of the opportunity to host a community solar project, but every school within that district (as well as similarly-situated districts) would be unable to do so. The Agency accepts the proposed modifications to include the ability for the school district to serve as the subscriber/anchor tenant for community solar projects hosted at a public school. IPA Resp. at 48.

Likewise, the Agency understands that it may be difficult for a school district to predict the levels of student enrollment – and thereby, energy usage – for the next 20 years. While the Agency already has guidelines in place that would allow a community solar subscriber to modify subscription levels, there should be additional flexibility that would allow the anchor tenant of a public school community solar project to transfer their subscription to another school/district and increase/decrease the subscription size (within the definition of an anchor tenant) as needed. However, in order to ensure that the benefits of the Public Schools category go back to the schools that host these community solar projects, the Agency proposes that the requirements surrounding the subscription itself remain in place, and schools/districts may request a waiver from the requirements as necessary at any point during the 20-year subscription term. The Agency will develop the waiver process through a stakeholder feedback process and publish the information related to the waiver in the ABP Guidebook. IPA Resp. at 48-49.

In its BOE, the IPA responded to the JSPs' request for clarification. The IPA notes that Section 1-75(c)(1)(K)(iv) of the IPA Act explicitly requires that projects within the Public Schools category must be located at public schools. Thus, the IPA disagrees with the JSPs' proposal to allow projects to be sited at district-owned land that is not adjacent to a public school. With respect to projects located at district-owned property adjacent to public schools, the IPA agrees that, if the land were used for school-related activities, a project could be sited on that adjacent property. IPA BOE at 23-24.

5. Commission Analysis and Conclusion

The Commission adopts the proposed modifications to the Plan that the IPA suggests in Response Comments. They are reasonable and address US Solar's concerns. The Commission notes that the Joint Solar Parties raise new questions in Reply Comments that the IPA and other parties have not had an opportunity to respond to these questions. The Commission agrees with the IPA that the statutory requirement under Section 1-75(c)(1)(K)(iv) of the IPA Act restricts eligibility of projects for this category to those that are installed "at" a public school. The Commission, however, also agrees with Staff's argument raised in its RBOE that because school districts only exist if there is a school, and as long as the project is located on school district land, then the project is in effect "installed at" a public school. Staff RBOE at 9-10. The IPA is directed to modify the LTRRPP to clarify that community solar projects developed on land adjacent to a public school or district-owned land may be eligible to participate in the Public Schools category.

E. Section 7.4.6 Equity Eligible Contractor ("EEC")

1. Joint Solar Parties' Position

The Joint Solar Parties have noted several components of the Equity Block that threaten to impose burdens on EECs that make it harder to build wealth than for other

direct and indirect participants in the ABP. The JSPs notes that Section 1-75(c)(1)(P) requires that “[a]ll programs and procurements under this subsection (c) shall be designed to encourage participating projects to use a diverse and equitable workforce and a diverse set of contractors, including minority-owned businesses, disadvantaged businesses, trade unions, graduates of any workforce training programs administered under this Act, and small businesses.” JSPs Obj. at 17-18.

The JSPs state that the quickest way for developers (as opposed to other participants like contractors or long-term owner/operators) to expand, create more jobs, and create wealth for owners is to sell the system after it has received an award but before construction begins. The Joint Solar Parties recommend that Approved Vendors that are EECs should be allowed to submit a system for a Part I application but sell that system to non-EECs prior to the Part II application and still have that system qualify for the Equity Block. The JSPs explain that between the Part I and Part II applications - for the most part after the award of the REC Contract but before construction commences - almost all early-stage developers sell their projects to long-term owner/operators. Non-EECs use this method to build wealth through sales without taking on the risk of securing financing or long-term operation - much less program compliance or administration of the REC Contract. The JSPs state that current market trends are for many solar companies to start in early-stage development and grow (in both experience and capital resources, through accumulation or through being purchased) to the point of being able to take on long-term ownership and operation. JSPs Obj. at 18-19.

The JSPs note that LVEJO argues in response that P.A. 102-0662’s goals “extend[] far beyond project initiation and quick profits. This [Equity Block] program aims to assist EECs’ development into mature and competitive contractors in the fast-expanding renewable energy industry.” See LVEJO Resp. at 10. While EECs may take multiple corporate forms under the statutory definition, the Joint Solar Parties suspect that many will be for-profit companies and note that in any event wealth-building requires generation of wealth. Quick—or, perhaps phrased more accurately, lower-risk—profits as a way to begin working in the industry are a far better way to develop into “mature and competitive contractors” or developers or owner/operators than to force EECs to take on all three roles (in addition tackling financing, power purchase agreement (“PPA”) origination, and other complex transactions). JSP Rep. at 18-19.

The IPA similarly argues that the JSPs’ “request to allow for the transfer of projects from an EEC to a non-EEC prior to Part II approval creates a situation where the recipient of State-administered incentive funding would be the non-EEC assignee, not the EEC-applicant.” IPA Resp. at 50. The Joint Solar Parties disagree with this statement. While certainly the long-term owner/operator will benefit from buying the project (otherwise it would not make the purchase), the EEC is able to make a profit on relatively lower risk by virtue of having special access to state-administered incentive funding. JSP Rep. at 19-20.

Also, the JSPs note that the IPA has interpreted the Equity Block as requiring the Approved Vendor submitting the project to be an EEC. The Joint Solar Parties fully support EECs taking on the role of submitting projects and administering the REC Contract if they wish to do so but note that there are different and additive capital and expertise requirements to submit a project and administer the REC Contract (not to

mention finance the project, whether for construction debt before selling to an end-use customer or engaging in tax equity financing). If EECs cannot sell projects after a successful Part I application but before construction begins as expressed above, EECs—especially those recruited into the industry—are faced with far greater financial and technical burdens than non-EEC entrants. The Joint Solar Parties look forward to hearing from EECs directly on this issue and working with stakeholders on legislative fixes if even allowing selling of projects after a project has been selected but before construction proves too much of a financial burden. JSPs Obj. at 19-20.

In addition, the Joint Solar Parties note that the Equity Block does not have a blanket cure provision that allows EECs a broader ability to cure deficiencies than other Approved Vendors performing under other blocks. As many EECs will be newer entrants and/or relying on newer entrants as their Designees, the ability to cure will both lower the stakes of on-the-job learning as well as lower the stakes with a purchaser (whether a long-term owner/operator or an end-use customer) that relies on receiving the full REC value. Similarly, the Joint Solar Parties fear that EECs may face demands for more stringent warranties and more intensive diligence because of their status as new entrants, which creates a needless drag on wealth creation. JSPs Obj. at 20.

Finally, the Joint Solar Parties provide a caveat to their recommendations by noting that most of their members are not EECs and the Joint Solar Parties do not speak for EECs, but that the members of the trade associations comprising the Joint Solar Parties have vast collective experience in creating and working with new market entrants. EECs are likely to face additional barriers that the Joint Solar Parties cannot speak for, but there is no reason to believe - and the IPA and LVEJO provides no evidence to the contrary - that the challenges facing new entrants that are not EECs will not also be challenges to EECs. JSP Rep. at 21.

For these reasons, the JSPs recommend that the Commission adopt the Joint Solar Parties' proposals regarding the Equity Block, or at minimum the Joint Solar Parties' proposal to allow EEC-Approved Vendors to sell before a Part II application to a non-EEC and the blanket cure for EECs. JSP Rep. at 21.

2. Joint NGOs' Position

Joint NGOs point out that Section 1-75(c)(1)(K)(iv) of the IPA Act, as amended by P.A. 102-0662, outlines a new category of the ABP specifically designed to support EECs. The Joint NGOs explain that the process for receiving certification as an EEC is outlined in detail in Section 7.7.3 of the Plan, but that process is for any entity involved in solar development (e.g. solar developers, Approved Vendors, Designees, etc.) which is majority-owned by Equity Eligible Persons. Equity Eligible Persons are defined to include those who participate in various statutorily-created job or contractor training programs, foster care alumni, formerly incarcerated individuals, or persons who reside in statutorily defined "equity eligible communities." 20 ILCS 3855/1-10; JNGOs Obj. at 2.

The Joint NGOs note that the EEC Category of the ABP is one of the three pillars of the Equity Accountability System outlined in Section 1-75(c-10) of the IPA Act. As described in that subsection, the Equity Accountability System, which includes the EEC category of the ABP, is designed to provide opportunities for disadvantaged businesses throughout the state via "priority access" to the state's RPS-driven REC procurement

programs. See 20 ILCS 3855/1-10. The EEC category was explicitly designed as a route to create this priority access. In the Joint NGOs' opinion, the Agency's proposed implementation of the EEC category could prove insufficient in satisfying this legislative mandate of providing priority access by creating barriers to certain disadvantaged businesses, particularly smaller businesses. JNGOs Obj. at 3.

The Joint NGOs note that the IPA's interpretation of the EEC category is that only EEC-certified entities may be involved in qualifying projects. This means that every stage of project development must be completed by an EEC. If solar companies were vertically integrated, if projects were originated, developed, and built by the same company, then the Joint NGOs opine that this could be a reasonable and prudent approach. The reality of the Illinois solar market is much more complex, however. For example, many companies, especially smaller companies, use Approved Vendor Aggregators to compile their projects and submit them to the ABP for REC contracts. Others develop the projects and interface with the state as Approved Vendors but then hire another contractor to do the project installations. JNGOs Obj. at 4.

In aggregate, the Joint NGOs assert that these small barriers could result in slow uptake of the EEC category. They explain that the category represents 10% of the ABP capacity, representing the significant commitment that P.A. 102-0662 makes to equitable access and inclusive growth. There are currently 1,030 Approved Vendors registered with the ABP, but only one of them is an EEC. The Joint NGOs recognize that the term EEC has only been functionally relevant for six months and that this may not represent the true number or proportion of potential EEC Approved Vendors. The Joint NGOs remain concerned that EECs present at various levels of the project development stack will be left behind for lack of available Approved Vendors and Approved Vendor Aggregators. JNGOs Obj. at 4-5.

The Joint NGOs urge the Commission to require that the IPA propose an alternative solution for implementing the EEC category, one that creates "priority access" for all EECs, such as by allowing EECs to partner in some fashion with non-EECs to support project applications that heavily involve EECs. The Joint NGOs do not claim to be experts on what counts as equitable and are therefore reluctant to propose specific solutions to this very real problem. But the proposal should not effectively exclude individual EECs and should result in substantial uptake and procurement within this critically important pillar of the Equity Accountability System. JNGOs Obj. at 5.

3. Staff's Position

Staff cannot support the Joint NGOs' or the JSPs' Objections. Staff agrees with the IPA's analysis that Section 1-75(c)(1)(K)(vi) is clear that the applicants must be EECs. The Joint NGOs' proposal could lead to non-EECs inappropriately benefiting from the category. Also, the JSPs' proposal would create a loophole, which the Plan should not allow. Staff Resp. at 19.

4. LVEJO'S Position

LVEJO is concerned that an application process that requires registration as both an Approved Vendor and as an EEC could act as a barrier to the participation of new EEC contractors. LVEJO proposes that the IPA take steps to streamline the application

process for entities applying to be both a new Approved Vendor and an EEC. LVEJO Obj. at 2.

According to LVEJO, a main focus of the EEC program and P.A. 102-0662 is promoting equity and that using the same application process for both EEC and non-EEC Approved Vendor applicants does not produce an equitable result. LVEJO argues that a one-size-fits-all Approved Vendor model is not perfect in every circumstance. LVEJO proposes that by using flexibility for new applicants seeking Approved Vendor and EEC designations acknowledges the barriers to participation that EECs confront and advances the equity goal that is fundamental to the EEC program and P.A. 102-0662 LVEJO Obj. at 2-3.

LVEJO shares the Joint NGOs' concerns that the program continues to impose barriers for smaller or newer EECs to receive the priority access to the projects and resources that the program is meant to provide. LVEJO supports the Joint NGOs' proposals to address this issue, particularly allowing EECs to partner with non-EEC vendors in order to alleviate the burdens of seeing a project through every stage from early development to installation. While such a solution should become unnecessary as the number and types of EECs grows, LVEJO asserts this measure is necessary at the start of the program, when there are comparatively few EECs. LVEJO Resp. at 2.

The JSPs object that the current structure of the equity block effectively requires EECs to be both developers and full administrators of REC contracts. They point out that most developers do not take on that dual burden, instead only taking on one part of a project. They worry that forcing EECs to take on more roles in a project will be too big of a barrier for small and emerging companies, preventing them from applying for projects in that category. LVEJO shares the concerns that the current block design may be placing too many extra burdens on new EECs, but it does share those larger concerns and the desire for more EEC feedback on the program's design. As part of its larger Environmental Justice goals, LVEJO supports attempting to grow the number of small, equity and minority-owned contractors in the state, and it supports proposals to help remove extra barriers and extra burdens to those participating in the ABP. LVEJO Resp. at 5-6.

LVEJO also notes that the JSPs propose a new blanket cure provision in the equity block to allow EECs broader ability to cure deficiencies. This acknowledges that EECs are more likely to be smaller, newer contractors, and more likely to present initial deficiencies. As a result, they may face harsher warranties without such a provision. LVEJO supports this proposal as a means to provide extra support for new EECs. LVEJO believes that encouraging the entry of new equity and minority-owned contractors into the industry is crucial for the LTRRPP to reach its larger equity goals, and that this objection helps to advance that purpose. LVEJO Resp. at 6.

In its Objections to the LTRRPP, the Joint Solar Parties argue that the IPA should allow EECs to sell EEC allocated projects to non-EEC Approved Vendors once their projects are Part I verified. While LVEJO appreciates JSPs' stated objectives, LVEJO opposes this suggestion. LVEJO notes that P.A. 102-0662 modified the ABP by, among other things, creating three new program categories. The EEC project category was among these new categories created by P.A. 102-0662. P.A. 102-0662 requires that at

least 10% of the ABP generation capacity be allocated to EECs. This allocation is set to increase to at least 40% by 2030. The General Assembly stated that the program is intended to increase “access to and development of equity eligible contractors, who are prime contractors and subcontractors, across all of the programs [the IPA] manages.” LVEJO Resp. at 9.

LVEJO maintains that this program aims to assist EECs’ development into mature and competitive contractors in the fast-expanding renewable energy industry. This goal would be undermined if the IPA were to adopt the JSPs’ suggestion that the only qualification to participate in the EEC category of the ABP is that a project originates from an EEC-Approved Vendor. LVEJO is concerned that adopting this suggestion would lead to wealth-building for EEC developers at the expense of EECs involved in later stages of projects. LVEJO states that the only way to meet the stated goal of this program and ensure that EEC contractors develop into stable and competitive companies is to ensure that all aspects of EEC projects, from project initiation to construction and maintenance, must be conducted or lead primarily by EECs to qualify for the EEC allocation. LVEJO Resp. at 10.

Further, LVEJO notes that nothing prevents an EEC contractor from participating in other non-EEC project categories. The LTRRPP allows EEC contractors to “submit projects into other program categories and are not limited to the EEC category.” If an EEC wishes to participate only in the initial application stage of a project and then sell those projects to other non-EEC AVs, the EEC may do so. LVEJO Resp. at 10.

5. IPA’s Position

First, the IPA notes that the Joint Solar Parties recommend that EEC Approved Vendors be allowed to submit a system Part I application, sell the system to a non-EEC Approved Vendor prior to the Part II application, and have the system remain in the EEC category. The Agency has proposed that projects that receive a REC Contract under the EEC block may not be assigned to an Approved Vendor that is not also a certified EEC for six years after the Part II verification date of the project. IPA Resp. at 49-50.

The IPA understands the JSPs’ arguments and is sensitive to the fact that EECs face additional barriers that compound the difficulty of starting a new business and building wealth. The Agency is permitted to advance funds to these applicants—directly assisting with one of the barriers to participation noted by JSP—for the purpose of developing and building the project. An EEC applicant has the ability to apply a project, receive a REC award at the same price as a non-EEC applicant, and apply for capital advancement for that project. If the EEC is not taking advantage of the capital advancement, the only purpose for applying into the EEC block would be to access capacity when all other blocks are full. Ultimately, the JSPs’ request to allow for the transfer of projects from an EEC to a non-EEC prior to Part II approval creates a situation where the recipient of State-administered incentive funding would be the non-EEC assignee, not the EEC-applicant. IPA Resp. at 50.

The Agency recognizes that its proposal may potentially foreclose an opportunity that some current market participants have used to grow their businesses, but the traditional pathway to success is not the only one, and the Agency commits to working

with EECs to assist in removing and reducing barriers to participation wherever possible. IPA Resp. at 50-51.

Second, the JSPs complain that the IPA has interpreted the Equity Block as requiring the Approved Vendor submitting the project to be an EEC. The IPA argues that Section 1-75(c)(1)(K)(iv) of the IPA Act requires the Agency to ensure that applicants - those "submitting the project" - are EECs. The ABP has, since its inception, used only Approved Vendors to apply projects to the program, and it is logical that the General Assembly knew and understood this requirement in drafting this text. IPA Resp. at 51-52.

The IPA notes that the JSPs point out that EECs face far greater financial and technical burdens than non-EEC applicants and point out their willingness to work with stakeholders on legislative fixes if necessary. The Agency appreciates the commitment of the JSPs and hopes that they will provide useful feedback in the development of the ABP's new mentorship/training program, explained in Section 7.2 of the Plan. IPA Resp. at 52.

The IPA notes that the Joint NGOs advocate for the modification of Plan provisions regarding eligibility for and utilization of the EEC category of the ABP. The Joint NGOs interpret the Plan text to state that only EEC-certified entities may be involved in qualifying projects and that every stage of project development must be completed by an EEC. The Joint NGOs recognize that very few of the participants in the ABP are vertically integrated and able to originate, develop, and build their own projects. IPA Resp. at 54-55.

As explained within the Plan, the Approved Vendors participating in the EEC category must be EEC-certified. A vertically integrated solar company that is registered as an EEC-Approved Vendor would qualify for the EEC category. As correctly noted by Joint NGOs, however, past experience in the ABP has shown that the market is much more disjointed, with multiple entities working on various portions of a single project. IPA Resp. at 55.

The Agency recognizes, however, that the Act does not require that all participating entities involved in the sale, development, and construction of a project be EECs, nor does it require a minimum percentage of participation from EEC Designees. Furthermore, the Agency is not certain that EEC Designees are available to begin working on these types of projects immediately, thereby making it more difficult for an EEC-AV that is not vertically integrated to participate. Accordingly, the Agency will modify Section 7.4.6.2 to clarify that Approved Vendors may work with non-EEC Designees and subcontractors on EEC category projects. The Agency will continue to monitor this segment as this category grows, and will re-evaluate, no later than the next Plan process, whether additional protections are necessary as the market evolves. IPA Resp. at 56.

LVEJO suggests that a solution that allows the open participation of non-EEC entities within the EEC category should become unnecessary in the future, as EECs grow in number and size. The IPA states that it will monitor this segment as this category grows, and will re-evaluate, no later than the next Plan process, whether additional guidelines on the participation of non-EECs are necessary as the market evolves. The IPA believes that active monitoring of category participation and an ongoing commitment to reexamine project requirements within this category should be sufficient to alleviate the

concerns of Staff as to whether non-EECs are “inappropriately benefitting” from the category. The Agency is committed to ensuring the success of the EECs throughout its programs and especially within this particular category and looks forward to refining this policy under future Plans as the market segment grows and expands. IPA Rep. at 32.

Third, the JSPs complain that the EEC category “does not have a blanket cure provision that allows EECs a broader ability to cure deficiencies than other Approved Vendors performing under other blocks.” The IPA fully supports reducing barriers where possible in order to make the EEC category successful; however, the Agency is unsure whether a “blanket cure provision” is necessary in the case of the application process or allowable in the case of the REC Contract. IPA Resp. at 53.

For context, the IPA explains that a project application is a multi-step process overseen by the Program Administrator. The Administrator reviews project applications and requests additional information from the applicant as needed to verify the submitted information and approve the project at Part I. After Part I approval, the project will be placed into a batch of applications and submitted to the Commission for contract approval. A project may be built prior to the submission of a Part I application, but a Part II application cannot be approved until the project is completed and energized under the terms of the REC Delivery Contract. At Part II, the Program Administrator will again review a second application regarding the product’s build and energization to determine whether it needs additional information to approve the project. That Part II approval then allows for payment of incentive funding to the Approved Vendor. If the Program Administrator informs the Approved Vendor that a part of the project is not compliant with ABP requirements or the REC Contract, the Approved Vendor may make those changes and resubmit the project or appeal to the IPA directly. IPA Resp. at 53.

Considering the above, the Agency does not believe that a “blanket cure provision” is something that is entirely necessary in the application process. Currently, deficient applications are not kicked out of the ABP—rather, the application is put into a “Need Info” status to await the additional information requested by the Program Administrator. The Agency can commit to ensuring that EECs, as participants in the mentorship/training program, will receive the guidance necessary to assist them in navigating the application process. Furthermore, for systems that are withdrawn due to an error or noncompliance with Program requirements, the Plan provides that those participating in the mentorship program will have their application fees waived for a resubmittal that occurs within three months of the withdrawal. The Agency can commit to expanding this provision in Section 7.10.4 to encompass all EECs, not only those that participate in the mentorship program. If additional cure provisions are required in the REC Contract to address identified or potential barriers faced by EECs, the IPA will address those in the next REC Contract development process. IPA Resp. at 54.

The Agency is committed to the solicitation of stakeholder input and is specifically interested in EEC stakeholder feedback on the subject of eliminating or reducing barriers where possible. The IPA looks forward to working with EECs to identify these barriers and create solutions to ensure success within the Program. IPA Resp. at 54.

The IPA notes that LVEJO argues that the EEC application process should be streamlined to reduce and eliminate barriers to becoming an applicant. LVJEO proposes

that the Agency take steps to streamline the application process. At the outset, the IPA wishes to clarify how the application process currently works for entities wishing to become an Approved Vendor generally. Currently, there are 424 Approved Vendors in the ABP Program, 97 of which are single-project Approved Vendors. The Approved Vendor application is contained within the online portal, and once completed by the entity seeking approval as a registered Approved Vendor within the ABP, it is evaluated by the Program Administrator and, more often than not, approved. On occasion, the ABP Program Administrator does ask for follow-up or clarifying information from entities seeking Approved Vendor status prior to issuing its determination. IPA Resp. at 56-57.

In order to be certified as an EEC, the Approved Vendor will have to complete and submit an additional form that verifies the Approved Vendor is also a qualifying EEC. This form must be signed by each owner or board member within the organization whose qualification as an equity eligible person is relied upon to establish the EEC status, as well as an authorized representative of the Approved Vendor, should the qualifying owner or board member require additional authorization to certify the organization. This separate certification allows current Approved Vendors who are also EECs to quickly certify as such and begin participating in the EEC category. IPA Resp. at 57.

The Agency is committed to the success of the EEC category and recognizes that barriers to participation exist throughout the solar industry. The IPA will work to reduce and/or eliminate barriers to participation in its programs to the fullest extent possible. As a first step in this process, the Agency and its Program Administrator will streamline the application process in the portal, first and foremost by including the EEC certification document in the AV registration application to avoid a new participant to the program missing an essential step in becoming certified within the ABP. The IPA will convene a stakeholder process following the conclusion of this docket to identify barriers in the process and determine what further streamlining is necessary to increase participation by EECs. Furthermore, the IPA plans to rely upon the new mentorship and training program proposed in Section 7.2 of the Plan to assist EECs in navigating the ABP and its requirements. IPA Resp. at 57-58.

6. Commission Analysis and Conclusion

With respect to the Joint Solar Parties' proposal to allow an EEC Approved Vendor to transfer a project to a non-EEC Approved Vendor prior to the Part II application and still have that system qualify for the Equity Block, the Commission agrees with LVEJO that this program aims to assist EECs in developing into mature and competitive contractors in the fast-expanding renewable energy industry. This goal would be undermined by the JSPs' suggestion that the only qualification to participate in the EEC category of the ABP is that a project originates from an EEC Approved Vendor. The JSPs' proposal is not adopted.

The JSPs also complain that the IPA has interpreted the Equity Block to require that the Approved Vendor submitting the project must be an EEC. In setting forth the requirements of the ABP, the IPA Act states that:

The Adjustable Block [P]rogram shall include the following categories in at least the following amounts:

(vi) At least 10% from distributed renewable energy generation devices, which includes distributed renewable energy devices with a nameplate capacity under 5,000 kilowatts or photovoltaic community renewable generation projects, from *applicants that are equity eligible contractors*.

20 ILCS 3855/1-75(c)(1)(K)(iv) (emphasis added). The Commission finds the JSPs' proposal to be inconsistent with this clear statutory requirement.

The Commission notes with approval, however, the IPA's clarification in response to the Joint NGOs' Objection that it is not the intent of the IPA to preclude EECs from working with non-EECs. The Commission agrees with the IPA's observation that it is not certain that EECs are available to begin working on projects immediately, thereby making it more difficult for an EEC to participate. Accordingly, the Commission agrees with the IPA's proposed modification to clarify that Approved Vendors may work with non-EEC Designees and subcontractors on EEC category projects.

With both the blanket cure proposal and the registration process for EECs, the Commission accepts the IPA's assurances that it will endeavor to process these applications smoothly. For instance, the Commission notes with approval the proposed update to include the EEC certification document in the Approved Vendor registration application.

The Commission appreciates the IPA's commitment to continue to monitor this ABP category and to work with stakeholders to identify barriers and streamline the process. The Commission agrees that this is appropriate in this new program under P.A. 102-0662.

F. Section 7.5 REC Pricing Model, APP E REC Pricing

1. Joint Solar Parties' Position

The JSPs argue that the REC Pricing Model substantially underestimates the costs of critical physical components of solar systems due to factors including unprecedented increases in raw material prices over the last 18 plus months. The REC Pricing Model relies on a first quarter 2020 report from the National Renewable Energy Laboratory ("NREL"). While the JSPs agree that, generally, NREL is a reliable source, the first quarter 2020 cost information is outdated because it predated the substantial supply chain and raw material availability issues that the solar industry has experienced over the last 18 plus months. A study conducted with the Solar Energy Industries of America ("SEIA") and Wood Mackenzie ("WoodMac") illustrates the price increases well with quarterly comparisons. JSPs Obj. at 7.

The JSPs assert that the IPA did not support changes to the REC Pricing Model for component pricing. The JSPs maintain that the IPA's position on changes to the REC Pricing Model to reflect component pricing appears to be based on improper assumptions about the Joint Solar Parties' evidence and an incorrect reading of the evidence presented by the IPA. JNGO Rep. at 6.

First, the Joint Solar Parties note that the IPA cites a slide deck from NREL providing a limited update on the solar industry for the proposition that material prices have not increased by relying on findings about total system prices in Arizona, California,

Connecticut, Massachusetts, and New York. The slide deck clearly states otherwise, JSPs opine, as another slide from NREL's presentation illustrates that the price of polysilicon is relatively high and the increased price polysilicon is driving up wafer, cell, and module pricing. JSP Rep. at 6-7.

The Joint Solar Parties have three additional observations: 1) the WoodMac/SEIA study identified a lower global spot price for Mono-c-Si cells at the end of 2020 than the average price in the NREL study, but a higher global spot price for Mono-c-Si cells than the average price in the NREL study; 2) the IPA does not account for whether installed system price effects were based on confounding factors including earlier-procured components, due to systems being delayed (as was the case in Illinois) due to COVID-19; and 3) the NREL presentation cited by the IPA does not address other costs such as racking or inverter prices, all of which were described in the WoodMac/SEIA study. JSP Rep. at 7.

The IPA also rejects the WoodMac/SEIA study, suggesting that the data might be skewed by involvement of a trade association. The JSPs assert that Mackenzie, an independent research organization, is highly reputable and widely viewed as the gold standard for independent research and quantification. WoodMac analyzes solar markets and regularly produces reports. SEIA has been publishing similar market update reports since the 1970s. According to the JSPs, the solar industry across the U.S. relies heavily on these reports. The Commission should reject any suggestion that evidence outside of government studies are inherently skewed or incorrect. JSP Rep. at 7-8.

In addition, the WoodMac study was published before the war in Ukraine began in late February 2022. Thus, this study does not include the increasing costs of shipping, metals, and components, as well as the cost of waiting for goods delayed by supply chain interruptions. JSP Rep. at 8.

The Joint Solar Parties have provided the most recent and most complete data on costs and market trends. Because the IPA has shown no justifiable basis for rejecting the updated component cost information from the WoodMac/SEIA study, the WoodMac/SEIA study is consistent with preliminary data provided by the IPA, and the IPA provides no updated data about other components such as racking and inverters, the Commission should direct the IPA to use the WoodMac/SEIA study values to update component prices in the REC Pricing Model. JSP Rep. at 8.

The JSPs also recommend that the REC Pricing Model should use the pricing information for fourth quarter 2021 in the pages excerpted in Attachment A to update the REC Pricing Model to reflect the updated module, inverter, and racking costs and remove the 4% declining cost assumption from this iteration of the LTRRPP.

The JSPs note that IPA adopted the Joint Solar Parties' and SolAmerica's recommendation to remove the 4% decline between blocks. The Joint Solar Parties appreciate the IPA's support on this component of the Joint Solar Parties' request. JNGO Resp. at 6.

The Joint Solar Parties state that many site hosts for Large DG systems are "subtype (f)" customers. Subtype (f) is a reference to Section 16-107.5(f) of the Act, which applies to (with trivial exceptions such as lighting) all non-residential customers with peak

demand of over 100 kW in ComEd or 150 kW in Ameren. 220 ILCS 5/16-107.5(f); JSPs Obj. at 8-9.

In assessing the potential net metering credit value, the JSPs explain it is important to consider the following facts. First, virtually all subtype (f) customers take service pursuant to the utilities' hourly supply tariffs. Under these, the customer pays the locational marginal price for energy each hour (per kWh) and pays a non-volumetric, demand-based (per kW) charge for capacity. ComEd customers pay a per kWh transmission charge, while Ameren customers a non-volumetric demand (per kW) charge for transmission. See ILL C.C. No. 10, 3d Revised Sheet No. 35 (ComEd); ILL. C.C. No. 1, 2d Revised Sheet No. 50.001 (Ameren). Nevertheless, the net metering credit only reflects the locational marginal price and the hourly purchased electricity adjustment. See, e.g., ILL C.C. No. 10, Original Sheet No. 301.1 (ComEd); ILL C.C. No. 1, 1st Revised Sheet No. 24.008 (Ameren). Furthermore, it is not even clear that there is a reduction to Ameren's or ComEd's transmission charge assessed to the retail customer based on the production of the behind-the-meter system. JSPs Obj. at 9-10.

Second, Section 16-107.5(f)(2) requires electricity providers to provide a credit at their "avoided cost of electricity supply." For customers with demand-based capacity and transmission charges, there is no guarantee that solar energy will reduce capacity and transmission costs passed through to the customer. This is because without a battery, there is no way to align the output of a solar system during those specific peak hours that ComEd and Ameren use to set a customer's allocations of capacity and transmission. Whether a solar system reduces demand-based (per kW) charges by any significant margin is dependent on weather conditions, cloud cover and the time-of-day when system peaks are set; in other words – factors wholly outside the control of the photovoltaic system owner and customer. JSPs Obj. at 10-11.

Even if the subtype (f) customer is served by an ARES under a product where energy, capacity, transmission, and other charges are rolled into a single price per kWh, the ARES is assessed capacity and transmission charges based on a customer's peak load contribution (capacity)/network service peak load (transmission) by the regional transmission organization. The ARES does not avoid any capacity or transmission costs for a particular billing period if the solar system generates kilowatt-hours during that billing period. Thus, unless the ARES and customer negotiate at arms-length a different approach (as is permitted by statute), the "avoided cost" is only related to energy and has the value of the locational marginal price. JSPs Obj. at 11.

The Joint Solar Parties do concede that it is possible that a Large DG customer will receive some reduction in the current delivery year for the generation of its system during the previous year, at least to the extent that the system reduced the customer's demand from the ComEd or Ameren system during the specific moments when peaks were set and the retail customer's rate or product passes through those savings. The Joint Solar Parties note, however, that when evaluating the economics of potential solar, subtype (f) customers and their internal and/or external energy managers generally do not consider meaningful demand charge reductions from solar systems that are not paired with energy storage when pricing. JSPs Obj. at 11-12.

By assigning capacity and transmission value to the net metering credit for subtype (f) customers, the IPA has bolstered the presumed value from onsite solar systems in a manner inconsistent with how customers recognize their value, erroneously depressing REC value on the other side of the equation. Large DG solar developers cannot simply raise rates to make up for this “revenue gap” without significantly shrinking market demand. JSPs Obj. at 12.

In addition to the capacity and transmission value, the REC Pricing Model assumes that for every kWh generated by the solar system there is an avoidance or credit for volumetric delivery charges such as the RPS charge, the zero emissions credit (“ZEC”) charge, the environmental recovery charge, and the like. For these reasons, the IPA should not include a net metering credit for Large DG customers for capacity and transmission. Neither ComEd Rider POGNM nor Ameren Rider NM provides for those credits for utility-supplied customers, nor does Section 16-107.5(f) require different credit calculations from ARES for ARES-supplied customers. JSPs Obj. at 12.

As a result, the REC Pricing Model should be amended to remove capacity and transmission from net metering values for Large DG and public schools systems. In the alternative, the IPA should model systems 25 kW and below—which are less likely to be on subtype (f) customers—to include capacity and transmission credits but all systems greater than 25 kW—which are more likely (and, after a certain point, almost certain to be) subtype (f) customers—not assume any capacity or transmission value for net metering credits. In addition, the JSPs reserve the right to address the treatment of the other billing components (RPS charge, the ZEC charge, the environmental recovery charge, etc.) during a subsequent filing, after responses to discovery have been received. JSPs Obj. at 12-13.

The Joint Solar Parties note that the IPA rejects proposed changes on the basis that they will require substantial changes to the REC Pricing Model and that the price effect could be significant. The JSPs aver that the Commission should reject both rationale and direct the IPA to make the changes to the REC Model supported by the record in this docket to address the very real modeling problem identified by the Joint Solar Parties and SolAmerica that Staff agree exists. JSP Rep. at 10.

ComEd and Ameren both disagree with the Joint Solar Parties’ description of net metering revenue. The JSPs state that Ameren appears to mistake Large DG for community solar, citing extensively from “Methodology D” in Rider NM 2, which applies exclusively to community solar subscribers. Thus, Ameren - while factually accurate - is completely inapposite to the Joint Solar Parties’ argument that is exclusively about behind-the-meter systems that would receive a credit under Methodology B. ComEd relies on the value of capacity reductions, which the Joint Solar Parties acknowledge are possible but are not assumed in PPAs or other commercial transactions because the value is seen as speculative. JSP Rep. at 10.

As a result, the Commission should adopt the Joint Solar Parties’ Objection and direct that the REC Pricing Model be amended to remove capacity and transmission from net metering values for Large DG and public schools systems. JSP Rep. at 11.

The JSPs further note that one of the categories in the REC Pricing Model’s costs for a project is “Developer Costs and Fees,” which represents both the cost of developing

a system and the fee a developer should expect to receive. For systems above 2,000 kW, the estimated development costs and fees are cut by a third for 5,000 kW systems - to the point where the anticipated development fee is approximately \$70,000 less in absolute dollars for a 5,000 kW system than a 2,000 kW system. JSP Obj. at 13-14. The IPA agreed with the proposed change and the JSPs aver that the Commission should thus approve the IPA's proposed changes to the REC Pricing Model. JSP Rep. at 11-12.

The JSPs also argue that utilization of federal tax credits, i.e., the Investment Tax Credit ("ITC"), at 100% of value is legally accurate but not factually accurate. The JSPs explain that third-party tax equity investment is a complex and expensive endeavor. While it is accurate to say that 100% of ITC-eligible costs receive the credit, it is also not realistic to impute 100% of the ITC value to the developer without a discount that reflects the intensive transaction costs. The Joint Solar Parties estimate that the transaction cost is approximately 25-30% of the ITC value, meaning for every dollar of ITC a project is eligible to receive generally speaking it will receive only 70-75 cents. The Joint Solar Parties suggest an estimate of 80% to reflect the reality that a very large number of systems - if not the overwhelming majority - use third-party tax equity investment to monetize the ITC. JSPs Obj. at 15.

The JSPs note the IPA opposes this proposal, but the JSPs argue that the impact on REC prices is not justification for failing to make the REC Pricing Model more accurate, especially given the IPA's ability to adjust downward the REC Pricing Model results. With respect to granularity, the Joint Solar Parties note there is a specific cell in NREL's Cost of Renewable Energy Spreadsheet Tool ("CREST") model to address tax credit utilization rate (Cell Q22 on the CREST Inputs worksheet in Appendix E), showing that NREL intended to allow for flexibility for such a substantial revenue stream to be less than 100% monetized. The IPA can add this change without modifying the structure of the CREST model, because the functionality is already included. JSP Rep. at 12-13.

The Joint Solar Parties' note that ComEd argues that the only systems that will incur these costs are the small universe of systems with lessors or buyers that are without their own taxable income necessary to claim the tax credit. ComEd is correct that system owners that have sufficient taxable income may elect to self-monetize federal investment tax credits, however the Joint Solar Parties maintain that the universe of systems that seek third-party tax equity financing is not small and ComEd provides no data to suggest otherwise. To the contrary, data from Lawrence Berkeley National Lab shows that solar is increasingly being adopted by middle (and lower) income households that are increasingly less likely to be able to self-monetize federal tax benefits. The Commission should reject ComEd's opposition to the Joint Solar Parties' ITC utilization percentage proposal. JSP Rep. at 13.

In addition, the JSPs explain that under current tax law, the bonus depreciation percentage goes down from 100% for systems placed in service on or before December 31, 2022 to 80% for systems placed in service through December 31, 2023 and down to 60% thereafter. For blocks opened in late 2022 - especially community solar if it is opened on the proposed timeframe of November 1, 2022 - it is not realistic to expect systems to be placed in service by December 31, 2022, and thus the 80% bonus depreciation level should be used in the REC Pricing Model. JSP Obj. at 14-15.

With regard to reducing bonus depreciation, the IPA, SolAmerica, and Joint NGOs agree with the Joint Solar Parties. ComEd opposes the change based on inapposite time value of money considerations, while correctly conceding that the value of bonus depreciation is dependent on the placed-in-service date. As a result, the Commission should approve the IPA's adoption of the Joint Solar Parties' proposal. JSP Rep. at 12.

The Joint Solar Parties state that they also discovered that several substantial cost categories in the REC Pricing Model (including Generation Equipment, Balance of Plant, Development Costs, and Fees) appear to incorrectly reference the direct current capacity for Large DG for Traditional Community Solar and CDCS. JSPs Obj. at 16. The IPA agreed with the Joint Solar Parties' Objection and stated that it has already fixed the issue. No party appears to have opposed the Joint Solar Parties' Objection; as a result, the Commission should approve the IPA making the technical correction as described in the IPA's Response Comments. JSP Rep. at 14.

The Joint Solar Parties also propose that the REC Pricing Model be adjusted to reflect the possibility of additional tariffs being imposed. They explain that on February 8, 2022, Auxin Solar, Inc. petitioned the U.S. Department of Commerce to impose additional tariffs on solar panels manufactured in certain southeast Asian countries. On March 28, 2022, the Department of Commerce announced that it would consider doing so. According to a fact sheet assembled by SEIA, the crystalline silicon modules impacted account for 65% of imported solar panels and the potential tariffs could be in the 50-250% range. Moreover, if additional tariffs are imposed, they would be applied retroactively to March 28, 2022. The financial impact on potential and already bid systems would be substantial, given that solar modules are one of the largest single costs related to development and construction. Furthermore, the retroactive nature of the petition has already begun to stress supply chains and drive-up prices, which is likely to last until well after a decision is made, even if a tariff is ultimately not adopted. The Joint Solar Parties thus recommend that the LTRRPP be modified to include an automatic adjustment to the REC Pricing Model, retroactive to the 2021-22 block opening date for each category of system, to account for the actual tariff imposed on a dollar-for-dollar basis. In the absence of such an automatic adjustment, the negative impact of the proposed low REC values will be further exacerbated. JSPs Obj. at 16-17.

The IPA agrees with the Joint Solar Parties and Joint NGOs that the impact is potentially significant but proposes a wait-and-see approach before taking action. The IPA notes that it can adjust pricing up to 10% or seek reopening if a larger adjustment is needed. While the Joint Solar Parties appreciate both tools, the 10% increase may be inadequate and reopening could take months to reach a conclusion, leading to more delays. JSP Rep. at 14-15.

Staff opposes an automatic adjustment, arguing that when the LTRRPP is next updated, prices will be revisited, at which time all increases and decreases in cost inputs, including International Trade Tariffs, can be considered. The JSPs assert that this approach ignores the potentially retroactive nature of the tariffs, the specific dates when tariffs may be recommended or enacted and runs the risk of widespread inability to make projects work financially under 2022-2023 block pricing. The JSPs explain that if tariffs are imposed, it will occur between the time the Commission approves final REC pricing and before the pricing will be updated for the 2023-24 block. If significant tariffs are

recommended or implemented on those dates, the 2022-2023 block pricing will be immediately inadequate and the IPA will fall far short of filling the blocks until June 2023. JSP Rep. at 15-16.

The Joint Solar Parties alternatively recommend that the Commission give the IPA authority to—separate and apart from the 10% discretionary adjustments - adjust REC prices for the blocks opening in 2022 up to dollar-for-dollar without further Commission approval. JSP Rep. at 15.

The Joint Solar Parties note that ComEd proposes further segmenting the ABP REC Pricing Model by providing different pricing for systems that are owned by the end-use customer. The JSPs opine that ComEd's comments are neither informed nor supported by evidence. The Commission should reject ComEd's proposed changes to the LTRRPP REC Pricing Model. JSP Resp. at 3-4.

As an initial matter, ComEd makes blanket assumptions about retail customers that it does not support related to monetizing federal tax benefits. Sophisticated commercial customers as well as wealthy residential customers may be able to fully monetize the federal ITC, while sophisticated commercial customers and a subset of residential customers (whose home is held by a corporate entity) may be able to fully monetize federal bonus depreciation. In addition, the Joint Solar Parties are not currently aware of any ABP systems other than residential behind-the-meter systems where individual residential customers own part of the system—the Joint Solar Parties believe that residential customer ownership outside of residential behind-the-meter systems is not prevalent. Thus, at best, ComEd's justification to bifurcate incentives for customer ownership is limited to residential customers of behind-the-meter systems. JSP Resp. at 4.

Second, ComEd raises the particular issue of incentivizing public schools to self-own (rather than finance through a lease or PPA). The JSPs state that ComEd provides no indication as to what benefit schools would have by avoiding third-party financing or lease. ComEd also does not describe the financing opportunities that are only available if a school owns the system. JSP Resp. at 4.

In the JSPs' opinion, ComEd's proposal to increase incentives for systems where the retail customer owns the system harms ratepayers. ComEd seeks to subsidize customers who cannot or will not monetize federal tax benefits using ratepayer funds without explaining the offsetting benefit to all ratepayers of that additional incentive. In addition, the JSPs aver that ComEd's proposal harms the RPS budget, because it adds costs in a way that does not advance a particular statutory or policy goal. The JSPs assert that the Commission should reject ComEd's proposal. JSP Resp. at 5.

The JSPs next note that the Joint NGOs propose what they term a "market-based" approach to increasing REC prices in the middle of an annual block if the block is slow to fill. The Joint Solar Parties share the same goals as the Joint NGOs. However, the Joint Solar Parties fundamentally believe that the ABP and ILSFA programs (or, more accurately, subprograms) will not succeed unless the REC Pricing Model accurately represents the costs and revenues associated with developing, constructing, owning, and operating the particular solar facilities. Any price adjustments that are not related to accurately reflecting costs and revenues undermines predictability. JSP Resp. at 5-6.

Respectfully, the effort that the IPA might put into assessing the market and eliminating confounding data (especially given the IPA's concern that it is "unclear" how such an approach would work) would be better spent refining the cost inputs and identifying non-cost barriers. JSP Resp. at 6.

In addition, the Joint Solar Parties argue that the statutory framework of the ABP does not support a "market-based" mechanism. See 20 ILCS 3855/1-75(c)(1)(K). The JSPs point to Docket No. 19-0995, where the Commission rejected another "market-based" approach to ABP pricing (a reverse auction approach) as contrary to an earlier (but similar) version of Section 1-75(c)(1)(K): "the Commission agrees with the other parties that it violates the statute's requirement that the LTRRPP must include a schedule of standard block purchase prices." See *Ill. Power Agency*, Docket No. 19-0995, Final Order at 44 (Feb. 18, 2020); JSP Resp. at 6-7.

The Joint Solar Parties are further concerned that the Joint NGOs' proposal could lead to perverse incentives for developers. Specifically, a developer could decide to take on the risk to develop a portfolio in a particularly underutilized block but hold off on submitting until the IPA raises prices (likely unaware of the amassing portfolio and thus unable to accurately gauge demand). A transparent, predictable pricing mechanism removes the incentive for a developer to strategically withhold projects in an attempt to induce a price increase. JSP Resp. at 7.

The Joint Solar Parties thus recommend that the Commission consider the further evidence provided by the Joint NGOs about the problem of underutilized subprograms but adopt the solution of ensuring accurate inputs into the REC Pricing Model and identifying/removing barriers to participation as proposed by the Joint Solar Parties. JSP Resp. at 7.

The Joint Solar Parties state that days before Response Comments were due, Ameren and ComEd filed with the Commission increased energy prices. For ComEd, prices increased by 65% and for Ameren prices increased by over 140%. The Joint Solar Parties state that, if the IPA follows its historic practice, it will update the REC Pricing Model with the new price information. This will lead to a precipitous drop in REC prices. JSP Rep. at 16.

The Joint Solar Parties do not object to drops in REC Pricing Model output that are associated with more accurate modeling, but in this case the Joint Solar Parties believe that the 2022-2023 values are likely outliers. In fact, both are subject to change based on an upcoming supplemental procurement. The JSPs also explain that in the future, electricity prices could temporarily bottom out, putting strain on systems already in service but creating a more lucrative REC than may be justified. A cycle of short-term highs and lows for REC pricing undermines the predictability and stability of the ABP in contravention of Section 1-75(c)(1)(K) that the ABP "enable the photovoltaic market to scale up and for renewable energy credit prices to adjust at a predictable rate over time." 20 ILCS 3855/1-75(c)(1)(K). JSP Rep. at 16-17.

To both address the immediate issue and impose a neutral solution that addresses market changes that would shock REC prices downwards or upwards, the Joint Solar Parties recommend that the Commission direct the IPA to input a five-year average Price to Compare rather than just Delivery Year 2022-2023 values. This will prevent what the

Joint Solar Parties believe is a temporary increase from creating a large number of systems whose REC price is based on unjustifiably high net metering revenue assumptions. JSP Rep. at 17.

2. Joint NGOs' Position

The Joint NGOs assert that changes to the ABP structure as a result of P.A. 102-0662 require a modified approach to REC pricing. First, P.A. 102-0662 created several new project categories in the ABP: EECs, CDCS, and Public Schools. Second, P.A. 102-0662 requires a transition to annual blocks, instead of opening subsequent blocks when open blocks reached capacity. See 20 ILCS 3855/1-75(c)(1)(K); JNGOs Obj. at 5-6.

The transition to annual blocks removes the linkage to stepped blocks with prices presumed to decline at 4% per block in the original structure. The IPA correctly finds that the concept of 4% declines between blocks no longer fits the program design and the IPA instead proposes to conduct an annual update to REC prices. JNGOs Obj. at 6-7.

Taken together, these developments (both the maturation of the program and the changes directed in P.A. 102-0662), support the movement toward a market-informed model focused on determining REC prices that will achieve the broad statutory REC deployment goals within the existing budget. While oversupply of available projects in some categories has been a concern, there are categories in both the ABP and ILSFA programs that are currently, or may likely in the near future, experience under procurement. A more market-based approach will allow the IPA to address both oversupply and under procurement. JNGOs Obj. at 7.

The ABP is at its heart a REC procurement program and each element of the program design should be aimed at deploying DG to achieve the overall RPS goals. The statute defines the relative weighting of each type of DG to be deployed. The Joint NGOs assert that a profitable and thriving renewable energy industry is a by-product of a predictable and successful program, but it is not the goal of the statute. JNGOs Obj. at 7.

As with previous LTRRPP iterations, the 2022 Plan proposes to continue to use a modified version of CREST to “develop a model for calculating REC prices.” This is a “cost-based” approach to REC pricing in that it sets REC prices for each category to achieve a certain predefined target return on investment given typical project cost, financial, tariff, and other assumptions for each type of project. Applying the cost model in this fashion includes an implicit assumption that the target return on investment will provide returns to prospective customers and developers at a cost that will procure the required RECs. It is this implicit assumption that the JNGOs propose to draw to the forefront of the decision-making process to improve accuracy and transparency. JNGOs Obj. at 7-8.

Although the IPA continues to rely upon the cost-based approach, the 2022 Plan recognizes that the Commission Order in the first revised Plan (Docket No. 19-0995) directed the IPA to take market prices into consideration: “For prices, the IPA must recognize market signals rather than solely relying on its cost modeling approach.” Docket No. 19-0995, Order at 46; JNGOs Obj. at 8.

The Joint NGOs recommend a staged approach to moving toward a more explicit price-response adoption model in the next annual update, discussed in greater detail below. In the meantime, this 2022 Plan should respond to current signals with respect to the new categories and the potential for under procurement in the ABP “Small DG” category, which supports small, behind-the-meter solar projects. These signals point to the need for higher REC prices for certain categories, especially the new categories in the ABP and the DG subprograms in the ILSFA program, and a reduction in the price decreases that have been proposed for the Public and Non-Profit Subprogram in the ILSFA program. JNGOs Obj. at 9.

In its Response Comments, the IPA remains committed to using administratively set REC prices based on cost modeling. The IPA also recognizes, however, that REC pricing requires further refinement in order to achieve the goals of efficient investment and become more responsive to market signals. Consequently, the IPA proposes to work with an independent expert consultant on providing recommendations on how to develop administratively-set REC prices that both efficiently invest ratepayer funds in renewables and respond annually to changing market conditions. The Joint NGOs appreciate this acknowledgement and commit to working with the IPA and its consultant to update and improve the adaptability of REC prices to empirical market observations and predictive models. JNGO Rep. at 6.

The Joint NGOs concur with the IPA's recommendation not to change the way that the depreciation, the federal ITC, and crediting transmission and capacity for outflow of Large DG systems are handled in its cost-based model. While the rationale that the IPA adopted for each of these topics is different, the Joint NGOs observe that they all relate to specific assumptions about project characteristics or business models across a broad spectrum of projects. Applying a single model to different types of projects necessarily requires simplifying assumptions about some variables. The IPA's assumptions about these topics are reasonable for some, if not many, projects within each category. However, the Joint NGOs point out that the combination of these and other simplifying assumptions made in the model illustrate the shortcomings of this cost-based model and show the importance of the IPA instead following market signals. Rather than trying to adjust every assumption underlying every variable in each group and category to accommodate all business models and structures, the IPA should focus on setting REC prices that will drive adoption at the required levels without overpaying. JNGO Rep. at 13.

The JNGOs also observe that the REC prices proposed in the LTRRPP for the Non-Profits and Public Facilities categories dropped significantly since the REC prices for the most recent program year. Compared to the REC prices for the current program year, REC prices dropped more than any other ABP category or ILSFA program. While supply has slightly exceeded available budget capacity in this sub-program, the increased funding available through P.A. 102-0662 and the narrowing of the eligibility may result in under procurement in this category, and as such the Joint NGOs recommend an upward adjustment to the development costs in the REC Pricing Model, pending a more thorough market evaluation in the upcoming first annual REC pricing update. JNGOs Obj. at 10.

In its Response Comments, the IPA proposed to adjust the REC prices for the Non-Profit and Public Facilities subcategory in the ILSFA program partly in response to

the Joint NGOs' Objections. The IPA noted that the proposed REC prices in its initial filed Plan dropped more than any other ABP category or ILSFA subcategory. However, the Joint NGOs note that the adjustment mechanism proposed by the IPA has a disproportionate impact on larger projects in the Non-Profit and Public Facilities category that results in smaller projects continuing to experience significant REC price drops. There is a negative impact on smaller NP/PF projects' REC prices when using the IPA's updated proposed methodology. JNGO Rep. at 7-8.

The Joint NGOs appreciate the IPA's proposed adjustment but have heard anecdotally from developers that have previously developed small Non-Profit and Public Facilities projects that the impact of the price declines will make it impossible to finance future small projects. Therefore, the Joint NGOs continue to believe that an adjustment to the development costs in the model for this subcategory is necessary and appropriate to make small projects viable. We urge the Commission to require the IPA to make such an adjustment. JNGO Rep. at 8.

The Joint NGOs note that the new Public Schools category of the ABP opened over four months ago. Also, P.A. 102-0662 requires that the Public Schools category comprise 15% of the total procured capacity of the ABP. At the current rate of adoption of zero, this goal will not be met. The Joint NGOs recommend increasing the REC prices for this category and propose creating an even higher REC price for Tier 1 and Tier 2 schools and those located in Environmental Justice communities. JNGO Resp. at 8-10.

In its Objections, ComEd shares the Joint NGOs' concern about the slow uptake of the new Public Schools category of the ABP. ComEd suggests that the IPA "forego its proposal to sunset public schools' participation" in the ILSFA Nonprofit and Public Facility subprogram. While this might help those schools that can participate through ILSFA, it is an insufficient solution to a larger problem: that the REC prices for the ABP Public Schools category are set too low. JNGO Rep. at 8-9.

The Joint NGOs explain that P.A. 102-0662 establishes that the new Public Schools category of the ABP will feature a longer 20-year REC contract delivery term. 20 ILCS 3855/1-75(c)(1)(L)(iv). This is unique to the Public Schools category, as everything but the traditional Community Solar category has a 15-year REC contract delivery term. While this leads to more REC payments over a longer period for the Public Schools category compared to these other categories, the longer REC incentive payment period can significantly alter the net present value of projects developed through this new category. JNGO Rep. at 9.

The Joint NGOs encourage the Commission to require the IPA to examine whether the proposed REC prices for the Public Schools category of the ABP match the net present value of projects submitted via the Large DG category, and if not, then increase the REC prices for Public Schools as needed. If the net present value of a project is significantly higher in the Large DG category, perhaps because of the accelerated REC incentive payment period, the Joint NGOs reason that solar developers will continue to avoid this new Public Schools category and instead submit school-based projects in the Large DG category. JNGO Rep. at 9.

Further, the Joint NGOs urge the Commission to require the IPA to create a separate track of REC prices for the disadvantaged schools that the category is designed

to prioritize, namely Tier 1 and 2 schools and schools located in Environmental Justice communities. The Joint NGOs support the IPA's decision to wind down eligibility for schools to participate in the ILSFA Non-profit and Public Facility subprogram, but only if there is a reasonable alternative for those customers. The IPA should consider replicating some of the successes from the Non-profit and Public Facility subprogram by increasing the REC incentives for disadvantaged schools and including a minimum savings requirement for projects meant to benefit those schools. JNGO Rep. at 10.

The JSPs object that the REC Pricing Model does not account for current component and material prices. The JSPs cite a quarterly study by the consulting firm and industry expert WoodMac that shows solar array component prices rising in recent quarters. The Joint NGOs state that this is consistent with other reports in recent months of supply chain disruptions since the 2020 NREL Annual Technology Baseline, which is used to set the cost basis for the Plan. The Joint NGOs explain that for years, NREL has served as a reliable and trusted cost benchmark, but the pace of changes has been significant as the U.S. is emerging from the pandemic and commodity and supply chain issues have disrupted the market significantly. JNGO Resp. at 11.

In their Objections, the JSPs and SolAmerica presented information demonstrating that component and material prices for photovoltaic installations have increased since 2020. The IPA dismissed this new data in its Response Comments, as well as the portion of the report by the WoodMac consulting firm, sponsored by SEIA and attached to the JSPs' Objections, which the JNGOs assert shows more recent data based on proprietary quarterly reports and further supports JSPs' and SolAmerica's arguments. The Joint NGOs note that the WoodMac study is considered one of the most reliable sources of information by industry insiders. Likewise, recent reporting by Bloomberg New Energy Finance ("BENF") illustrates the impact that supply chain disruptions are having on component prices. JNGO Rep. at 10.

The IPA cites a January 2022 presentation by NREL which appears to IPA to indicate that photovoltaic system prices were relatively flat in 2021 despite supply chain shortages and component price increase. The IPA found that the best data available from an independent source is the data provided by NREL. Thus, the IPA concludes that reliance on the Q1 2020 NREL data is reasonable and should be adopted. JNGO Rep. at 11.

The Joint NGOs appreciate the difficulty of finding reliable, independent, publicly available cost estimates for inclusion in the IPA's cost-based model. The Joint NGOs understand that IPA is not able to rely on more current NREL data, because of a change in methodology between 2020 and 2021, or on more accurate and granular commercial products, such as WoodMac and BENF, because they are proprietary. The Joint NGOs observe that the difficulty of accessing current, highly sensitive commercial information is one of the limitations of the cost-based model. This ongoing challenge supports Joint NGOs suggestion to move away from a cost-based model and towards a market-based approach. That said, as with other accommodations made in applying the current cost-based model, Joint NGOs find the IPA's approach of updating assumptions with a recent presentation by NREL to be reasonable and strongly support the removal of the 4% cost component decline recommended by JSPs and SolAmerica. JNGO Rep. at 11.

The Joint NGOs also agree with the JSPs' Objection regarding bonus depreciation. The Joint NGOs concur with the JSPs' observation that the timing of projects that will participate in the next blocks of the ABP are unlikely to realize the tax benefits assumed in the model due to the timing of the blocks and historical project completion timelines. JNGO Resp. at 12.

With respect to the JSPs' Objection regarding tariffs, the Joint NGOs agree that the Commission should direct the IPA to adjust prices for future RECs when the federal investigation is concluded, if needed. The Joint NGOs state that the current trade action has already caused dramatic disruption in the market and has the potential to worsen already tight supply chains and create additional upward cost pressure. JNGO Resp. at 12.

The IPA has stated that it believes that it is premature to speculate on the outcome of the tariff investigation. The IPA prudently suggests continuing to monitor the investigation and notes that it can address the matter through the development of the next annual REC Pricing Update, through the utilization of the IPA's discretion to modify REC prices up to 10% between plans, or through reopening. The Joint NGOs note that the IPA could also use its "discretion to modify REC prices up to 10% between plans" to address other pricing issues that arise and in response to market conditions, beyond just addressing the potential trade tariff. See 20 ILCS 3855/1-75(c)(1)(M). Through modifying the prices if needed, the IPA could gain additional experience with a market-based approach to REC pricing. JNGO Rep. at 12.

The Joint NGOs also note that the pricing model will be updated once upon publication of the final approved Plan. The Joint NGOs encourage the IPA to maintain flexibility as long as possible to adjust prices prior to the opening of the next blocks, in light of the ongoing uncertainty surrounding the trade complaint. The Joint NGOs do not believe that a retroactive adjustment for REC contracts already awarded and approved by the Commission would be advisable but support expeditious action by the IPA to make upward adjustments upon action by the U.S. Department of Commerce to impose new tariffs. JNGO Rep. at 12-13.

3. ComEd's Position

ComEd recommends that the REC Pricing Model calculate separate REC prices for owned systems and leased systems to reflect the unique economics and incentives available under each arrangement. For example, assumptions related to the ITC and bonus depreciation do not equally apply to both arrangements. The IPA's decision to apply 100% bonus depreciation to the up-to-10 kW project size admittedly favors third-party ownership – and thus a leasing structure – in the residential solar rooftop segment. Because this REC price will not align with homeowner-owned systems that cannot take advantage of bonus depreciation, the IPA's choice has the effect of discouraging homeowner ownership. Similarly, the ABP REC prices for public schools were generally modeled using the same assumptions applicable to ABP DG, which means that the REC prices will reflect adjustments for the ITC and bonus depreciation despite public schools not being able to take advantage of these benefits. ComEd Obj. at 14.

Moreover, ComEd argues that calculating separate REC prices for owned systems and leased systems would have the added benefit of allowing public schools to take

advantage of their own unique financing opportunities in a way that would empower the schools to maximize operational savings. These savings could then be reinvested by the schools to address other operational needs, which enables schools to expand educational or community programs and which aligns well with the equity goals of the Clean Energy Law given that Tier 1 and Tier 2 schools are prioritized in this program. ComEd Obj. at 14-15.

In response to the IPA and Staff, ComEd responds that using more precise data and inputs does not create biases in favor of one ownership structure or another, rather, it creates accurate price signals that properly reflect the economics of an ownership structure and arrangement. ComEd Rep. at 17.

Regarding the JSPs' recommendation that, for Large DG, the IPA should exclude from the REC Pricing Model the net metering credit values for capacity and transmission, ComEd opines that the JSPs misunderstand that the value of these credits will be realized by these Large DG systems regardless of whether they elect a DG rebate and no longer receive full retail rate net metering. Indeed, the provision referenced by the JSPs – Section 16-107.5(f) of the Act – requires that ComEd calculate and impute the value of capacity and transmission as part of the net metering credit calculation for customers on hourly supply service. In addition, the JSPs' claim that the calculation of the credit at the "avoided costs of electricity supply" must take into account that the value is weather dependent, fails to recognize that the system need only be reducing consumption during peak times in order to realize the benefits, and need not be actively exporting power to the grid. ComEd explains that any rooftop system that is operating during the peak hours (which are highly correlated with sunshine), reduces both the capacity obligation and the net system peak load contribution of the customer that the system is serving. The benefits of those reductions will either directly benefit the user or the user's load serving entity, which should be passed through to the customer regardless of whether that customer is served by ComEd or by an ARES. ComEd Resp. at 8-9.

With respect to the proposals to reduce the value of bonus depreciation for blocks opened in 2022 (to 80%) and to reduce the ITC to 80% to account for transaction fees, ComEd urges their rejection. The REC Pricing Model sets prices based on a 25-year series of cash flows, and the date of energization is largely irrelevant to the price being set. Rather, the price is established by the existence of the bonus depreciation – not based on which year the tax return can be filed. ComEd explains that the bonus depreciation is dependent on the year the capital expenditures are placed into service, and at most would result in those claims being in the subsequent tax year period if the system happens to be installed over two calendar years. Importantly, the REC Pricing Model does not take into account other minor timing effects that would also impact the values, nor should it, as the prices would therefore have to be calculated individually for each system based on each system's individual facts and circumstances, which would be tedious and burdensome. ComEd Resp. at 9.

ComEd states that the proposal to reduce the ITC to reflect transaction fees wrongly assumes that every transaction is a lease transaction that requires a tax equity partner (and thus will incur these costs). Not all systems – let alone all leased systems – will require tax equity financing. According to ComEd, the only systems that will incur these costs are the small universe of systems with lessors or buyers that are without their

own taxable income necessary to claim the tax credit. Even if a project incurs transaction fees, these are the sorts of costs and risks that are designed to be compensated by the 12% internal rate of return on after tax cash flow. If every cash flow in the REC Pricing Model were adjusted to account for every potential cost or timing delay to achieve a risk-free set of cash flows for the solar system in question, then the after-tax internal rate of return target used to set the price should be adjusted significantly downward to account for the lack of risk in the project cash flows. ComEd asserts that these proposals should accordingly be rejected. ComEd Resp. at 9-10.

ComEd also recommends that the IPA update the REC Pricing Model to account for the increases in energy prices in the ComEd and Ameren service territories that have been identified during the pendency of this docket. For example, the price of energy alone in the ComEd Zone is expected to increase nearly \$33 per MWh, which is an increase of 68% compared to the values known when the IPA filed its Plan. In particular, the delivery year supply rate for residential customers has increased by \$14 per MWh, which directly impacts the residential solar rooftop and community solar project pricing under the Model. ComEd Rep. at 15-16.

4. SolAmerica's Position

While the IPA has performed highly commendable work with a complex undertaking, SolAmerica asserts the "Development Cost and Fee" for Large DG projects sized from greater than 2 MWs to 5 MWs is too low. In fact, shown on the "Development Cost & Assumptions" Tab of IPA's model, the amount is less for these larger systems than it is for a significantly smaller system. Specifically, commercial and industrial system data has been applied for systems 2 MWs and under but utility-scale data for systems larger than 2 MWs. Instead of inappropriately relying on utility-scale data, SolAmerica opines that the model input should be an extrapolation from the NREL commercial and industrial data set only. SolAmerica Obj. at 2.

SolAmerica supports the Objections of the Joint Solar Parties related to other REC Pricing concerns, which include: 1) failure to recognize that bonus depreciation for systems put in service in 2023 will be 80%, not 100%; 2) the model erroneously assumes that Large DG customers will receive transmission and capacity savings which runs counter to industry experience; and 3) the model has applied the 4% reduction between blocks, intended to represent the industry's declining cost curve, even though it is well established that full install prices have gone up considerably, perhaps as much as 15%, over the last 18 months. SolAmerica Obj. at 5-6.

5. Ameren's Position

In their Objections, CGA, Joint Solar Parties, SolAmerica, and the Joint NGOs raised concerns regarding the IPA's proposal to lower REC prices. Ameren disagrees with those parties and agrees with the IPA that it is appropriate to lower REC prices. Ameren believes, as it has stated in previous proceedings, the prices of RECs were previously too high as witnessed by the substantial oversubscription in community solar and large DG. Ameren Resp. at 1-2.

Some of the parties objecting point to high costs for labor and materials as the rationale for not lowering REC prices. Ameren asserts that these arguments fail to

acknowledge that energy prices have nearly tripled over the last 12 months and capacity prices increased by a factor of forty-seven. Ameren believes that this will likely make solar projects more attractive to customers, thus increasing the demand for solar, which should be financially beneficial to developers. Ameren Resp. at 2.

Ameren points out that customers ultimately pay for RECs through a utility surcharge and their funds should be used in a meaningful and efficient manner. All of this justifies lowering REC prices as compared to prior years. Additionally, it should be noted that to the extent that demand for RECs is not sufficient, the IPA has the authority to revisit and raise prices later, if necessary. This authority should resolve the concerns of the parties who are concerned that lower prices will also drive down development. Therefore, Ameren recommends that the Commission adopt the IPA's proposal regarding the lowering of REC prices. Ameren Resp. at 2.

Staff argues that the upward adjusting on REC prices as suggested by the Joint NGOs would result in unnecessarily inflated REC prices that are paid for by ratepayers, and Staff cannot support a proposal where ratepayers end up paying inflated prices. Ameren agrees with this sentiment and notes that the Commission has recognized the importance to keep ratepayer in mind when setting REC prices. See Docket 19-0995, Final Order at 46. Therefore, Ameren agrees with Staff and recommends that the Commission reject the Joint NGO's proposal. Ameren Rep. at 2-3.

Ameren notes that the Joint Solar Parties request the Commission increase REC prices and remove transmission and capacity credits from the IPA's REC Pricing Model in part due to their belief that Ameren's net metering tariffs do not provide non-competitive service customers with a credit for capacity transmission charges. Specifically, the Joint Solar Parties assert that the IPA, by assigning capacity and transmission value to the metering credit for subtype (f) customers, has inappropriately bolstered the presumed value from onsite solar systems and thereby erroneously depressed REC values. Ameren Resp. at 2-3.

The arguments raised by the Joint Solar Parties are not completely accurate and are misleading. While it is correct that Ameren's Rider NM – Net Metering tariff does not currently provide a transmission credit for these customers, that tariff does provide a capacity credit. Furthermore, the Company's Rider NM2 – Net Metering 2 (Rider NM2) tariff, which was approved in Docket No. 21-0859 (in which the Joint Solar Parties actively participated) and which will go into effect shortly after the LTRRPP is expected to be approved by the Commission, specifically identifies both capacity and transmission charges as charges for which these customers will receive a credit. See Rider NM2, Sheet 29.011; Ameren Resp. at 3-4.

With respect to tariffs, Ameren believes that by ignoring other cost inputs, the JSPs are trying to create a pricing model that is not inclusive of all factors and therefore may not properly reflect the current market. Additionally, as noted by Staff, the Plan prices will be revisited and all applicable increases and decreases in cost inputs can be considered. For these reasons, Ameren agrees with Staff and recommends that the Commission reject the JSPs' proposal. Ameren Rep. at 3.

6. LVEJO's Position

LVEJO supports the Joint NGOs' objection regarding adjusting the REC prices for the EEC and Public Schools categories. As an environmental justice organization, LVEJO asserts that the success of these two categories is vital to achieving the larger equity-based goals represented in P.A. 102-0662. LVEJO shares the concerns of the Joint NGOs that the current REC pricing for these two categories may not accurately account for the additional costs and barriers that projects in these two categories face, and it supports efforts to ensure REC prices reflect these additional obstacles. LVEJO asserts it is essential to facilitate projects in these categories as a part of meeting P.A. 102-0662's equity goals. LVEJO Resp. at 2-3.

7. Staff's Position

ComEd objects to the Plan because it does not calculate separate REC prices for owned systems and leased systems. ComEd argues that those systems have different economics and incentives. Staff does not support ComEd's objection. While ComEd argues that the REC Pricing Model should set prices in a neutral manner, ComEd's proposal would have the opposite effect. Under ComEd's proposal, the pricing would create a bias that favors either owned or leased systems over the other. Staff agrees with the Plan that it would be inappropriate to calculate separate REC prices for owned and leased systems. Staff Resp. at 17-18.

The Joint NGOs object to the Plan for not adjusting REC prices upward for those ABP categories where the IPA expects there to be an undersubscription. Staff does not support JNGO's objection. It is to be expected that there would be a ramp up period for the three new categories of community driven solar, EECs, and Public Schools. The upward adjusting of REC prices as suggested by the Joint NGOs would result in unnecessarily inflated REC prices that are paid for by ratepayers, which Staff does not support. Staff Resp. at 19; Staff Rep. at 27.

The Joint NGOs object to the Plan because it does not direct the IPA to develop models to identify and diagnose market signals and causes for under procurements. Staff is not opposed to this suggestion, but only if the IPA has the resources to undertake what the Joint NGOs suggest. Staff Resp. at 19.

The JSPs and SolAmerica object to certain inputs in the Plan's REC price calculation for facilities greater than 2 MW. The IPA indicates that it will adopt the JSPs' and SolAmerica's recommendation to extrapolate NREL data from 2 MW systems for development costs and fees to create inputs for 5 MW system sizes. Staff is not opposed to the IPA adopting the JSPs' and SolAmerica's recommendation. Staff Rep. at 31.

Staff notes that the JSPs also object to the Plan's Large DG customer credits related to net metering. The JSPs argue that subtype (f) customers do not get credits for transmission and capacity. Based upon a review of the JSPs' Objections, it seems to Staff that there is an issue with respect to the credits related to transmission and capacity and urges the IPA to consider the arguments made by the JSPs. Staff Resp. at 20. Staff agrees with the IPA that for this Plan JSPs' objection should be rejected but the issue be looked at again for the next Plan. Staff Rep. at 30.

The JSPs object to the Plan because it does not include an automatic increase in the REC Pricing Model for any increases in international trade tariffs. Staff does not support the JSPs' objection. The JSPs focus on one possible increase in certain costs but do not consider that other costs could decrease in the future. Under the Plan prices will be revisited, at which time all increases and decreases in cost inputs, including international trade tariffs, can be considered. Staff Resp. at 21-22. Staff notes that the IPA responds that the more reasonable approach would be to monitor the situation and the outcome of the U.S. Department of Commerce investigation. Staff supports the IPA's proposal. Staff Rep. at 31-32.

8. IPA's Position

The Agency's REC Pricing Model is discussed in Section 7.5 of the Plan (and subsequent subsections), described in detail in Appendix D, and presented as a table in Appendix E. As explained within the Plan, the Agency is committed to ensuring transparency in developing the prices under the ABP and ILSFA Programs. IPA Resp. at 58-59.

The Agency notes that in the approval of the Revised Plan in Docket No. 19-0995, the Commission recognized that REC prices within the ABP must be lower, in part to efficiently invest ratepayer money. The Commission ordered the IPA to "recognize market signals rather than solely relying on its cost modeling approach," and directed the Agency to explore various proposals including a developer cap, collateral, and methods to reduce gaming. As outlined within the Plan, the Agency held workshops and solicited stakeholder feedback on REC pricing in 2020 through 2021 in preparation of its Second Revised Plan, which was published in August 2021 and withdrawn following the enactment of P.A. 102-0662. IPA Resp. at 59.

The REC Pricing Model submitted to the Commission in Appendix E to the Filed Plan contains updated modeling based upon the changes in law under P.A. 102-0662 and stakeholder feedback solicited in 2020-2021. This approach is primarily, though not exclusively, reliant upon updates to the Agency's previously-developed REC Pricing Model. The IPA strongly feels that given the many changing statutory requirements, especially the additions of new categories to the ABP, continued reliance on an updated version of the Agency's pre-established REC Pricing Model provides transparency into and valuable stability in REC pricing to program participants. The relative stability in pricing is beneficial not only to participants in the newly-expanded ABP, but also to the Agency in developing its budget modeling, which has become increasingly complex given the changes in goals, targets, and self-direct program options. It is particularly challenging at the onset of a new statutory regime to develop new budget modeling when so many of the underlying factors are shifting. The reliance on an updated version of the Agency's REC Pricing Model helps minimize these changes and provides stability to the process of budget modeling at the outset of implementation of a new LTRRPP. IPA Resp. at 59-60.

The Joint NGOs recommend the Commission "direct the IPA to set REC prices based on market signals (i.e., category or subprogram uptake) in their annual REC price update" and in the next LTRRPP. It appears to the Agency that the only market signal which appears to matter to Joint NGOs in this situation is the uptake in a particular

category of the ABP or subcategory of ILSFA. This definition of “market signals” is unreasonably narrow; if the proposal seeks for the IPA to incorporate additional market signals into this approach, they have not been identified with any specificity. The Agency does not support such a restrictive interpretation of what constitutes a market signal and urges the Commission to reject this recommendation. IPA Rep. at 44-45.

Furthermore, the Agency sees merit in considering some of the more general objections raised by commentors regarding the fundamental structure of the REC Pricing Model. In order to complete a thorough review prior to the next update of the Agency’s Long-Term Plan, the IPA proposes to work with an independent expert consultant on providing recommendations on how to develop administratively-set REC prices that both efficiently invest ratepayer funds in renewables and respond annually to changing market conditions. The Agency will commit to providing transparency around the results of this review and will utilize the independent analysis to craft REC prices for the next Plan. IPA Resp. at 61.

The IPA notes that the Joint NGOs object to the proposed changes in REC prices for the Non-Profit and Public Facilities subcategory. As correctly noted by the Joint NGOs, the REC prices in that category dropped more than in any other ABP category or ILSFA subprogram. Upon a review of the REC Pricing Model for the Non-Profit and Public Facilities category, the Agency found that the average subscriber savings of selected projects within the subcategory is 82%, while the model relies upon the assumption that savings for participants are only at 50%. The Agency proposes to update the inputs to the model to account for this additional savings. IPA Resp. at 62.

The JSPs argue that the REC Pricing Model substantially underestimates the costs of critical physical components of solar systems and complains that the REC Pricing Model relies upon outdated cost information from NREL from 2020 photovoltaic system and energy storage cost benchmark report. The JSPs offer only excerpts of a study conducted by SEIA (an industry association of photovoltaic developers that could have an interest in overestimating the costs of components) as more updated pricing that can be utilized in its place. The IPA avers that the best data available from an independent source is the data provided by NREL. IPA Resp. at 63.

The argument that the component price information utilized by the IPA should be rejected or discredited in some way due to its stale nature should be rejected. While NREL has not yet published a full update to the benchmarking report, a January 2022 NREL presentation shows pricing for solar systems in selected states. In developing the component and material price inputs for the Plan, the Agency compared component pricing from the 2020 to the 2021 report. Not only does the more recent 2021 NREL data discussed in the January 2022 presentation show that photovoltaic system prices were relatively flat in 2021, the presentation also states that this is true despite supply chain shortages and component price increases. The NREL data for 2021 actually shows lower component costs than the 2020 report for systems under 500 kW; it also indicates that in the only category where photovoltaic system costs had increased, they increased significantly more moderately than in the excerpted information provided by JSPs. The reported price increase for systems between 500 kW and 5 MW increased only 2%, significantly less than the cost increases purported to have been found in the excerpts of the SEIA report. In light of the fact that the JSPs advocate for the use of higher component

prices, the Agency finds that reliance on the Q1 2020 NREL data is reasonable and should be adopted. IPA Resp. at 63-64.

In addition to relying upon the 2020 NREL data for inputs, the REC Pricing Model contained in Appendix E included an assumption that component pricing would decrease 4% annually. The JSPs and SolAmerica object to this component pricing decrease. The IPA agrees that early indications from NREL are that component prices have stayed relatively flat. Accordingly, the IPA accepts the proposal to remove the 4% declining cost assumption for component pricing that is contained within the model. IPA Resp. at 64.

The JSPs, joined by SolAmerica, argue that the REC Pricing Model wrongly assumes that customers that install a Large DG system will receive transmission and capacity net metering, despite the fact that these customers receive net metering credits under Section 16-107.5(f) of the PUA and that the ComEd and Ameren tariffs that implement this Section of the PUA do not provide net crediting for transmission and capacity charges. The IPA explains that the adoption of the JSP/SolAmerica recommendation to remove the assumption that Large DG customers receive transmission and capacity crediting would require a significant overhaul to the REC Pricing Model. In order to make the JSPs' requested change to the model, the IPA would need to significantly redesign the Small DG pricing within the REC Pricing Model, not just the Large DG pricing. The Agency did a quick analysis and found that the impact on Large DG REC prices would be an approximate increase of \$7 per REC in that category. IPA Resp. at 65-66.

Ameren and ComEd both explain that large customer net metering credits are correctly included in the REC Pricing Model and urge the Commission to reject the arguments of the JSPs and SolAmerica seeking to remove the net crediting for transmission and capacity crediting from Large DG systems. Based upon the information provided in the Response Comments of Ameren and ComEd, it is clear to the IPA that subtype (f) customers will receive net crediting for capacity and transmission charges under the applicable utility's tariffs, and that the Objections of JSP and SolAmerica should be rejected. IPA Rep. at 36.

Furthermore, the IPA has already committed to an in-depth review of the REC Pricing Model with an independent expert consultant prior to the next update of its LTRRPP and will evaluate whether restructuring the model to more accurately account for the nuances of net metering policies across customer classes is possible. For this reason, any incorporation of these adjustments should occur through a review of the REC Pricing Model prior to the completion of the next Long-Term Plan. IPA Rep. at 37.

The JSPs raise the issue of the developer costs and fees for 5 MW systems, pointing out that those costs are a third less than the inputs for a 2 MW system within the REC Pricing Model, and argues that those costs should be increased. The Agency agrees with JSPs that the use of utility-scale inputs for 5 MW systems does convolute the outcomes of the REC Prices for 5 MW systems and provides an unintended result. The IPA likewise agrees with SolAmerica's reasoning that significant price differences between fixed rooftop or ground-mounted DG systems (which would be expected for a 5 MW DG system) and single tracking systems (which would be expected for a utility-scale system) render the development cost and fees utilized for 5 MW systems inappropriate.

Accordingly, the IPA has adopted the recommendation of the JSPs and SolAmerica to extrapolate the NREL data from 2 MW systems for development costs and fees to create inputs for 5 MW system sizes. IPA Resp. at 66-67.

ComEd recommends that the Agency revise the REC Pricing Model in “a neutral manner” in order to “calculate separate REC prices for owned systems and leased systems to reflect the unique economics and incentives available under each arrangement.” ComEd appears to specifically object to the application of 100% bonus depreciation for the up-to-10 kW AC project size. ComEd avers that inclusion of the 100% bonus depreciation in the REC pricing, when the advantage aligns with third-party owned systems, effectively discourages homeowner system ownership. While the IPA notes that changes to the calculation of separate REC prices for owned and leased systems has no significant impact on the difference in prices between the two, the removal of the bonus depreciation for projects 10 kW and smaller significantly increases the REC prices for those systems, which then leads to the opposite result of heavily favoring the purchase of systems rather than lease. The Agency therefore recommends that the Commission reject ComEd’s arguments on bonus depreciation. IPA Resp. at 68-69.

The JSPs raise an issue with the bonus depreciation value, noting that under current tax law, the bonus depreciation percentage drops from 100% for systems placed in service on or before December 31, 2022, to 80% for systems placed in service through December 31, 2023, and down to 60% thereafter. SolAmerica joins in the JSPs’ objection on this issue. Recognizing that the JSPs are correct in their statement that it is not realistic to expect that systems that receive a REC Delivery Contract in the 2022-2023 delivery year be placed in service by the end of the end of the 2022 delivery year, the IPA proposes a change to the assumption. The Agency recommends a reduction in the level of bonus depreciation to 80% to reflect the phase out. The phase out bonus depreciation will occur over four years: 80% will be allowed for property placed in service in 2023, 60% in 2024, 40% in 2025, and 20% in 2026. If adopted, this change will be reflected in the updated Appendix E that will be published contemporaneously with the Final Plan as modified by the Commission’s Order in this proceeding. IPA Resp. at 69.

In response to ComEd, the IPA notes that the proposal was not simply about the year in which the capital expenditures are made, but the structure of current tax law. Through utilization of bonus depreciation, system owners can currently deduct a percentage of the cost of the capital expenditures in the year of those expenses, and the remaining cost can be deducted over several years thereafter. The IPA’s proposal finds is a reasonable adjustment that properly recognizes the tax benefits that will be in effect at the time the systems are placed into service. IPA Rep. at 41.

The JSPs object to the utilization of the ITC in the REC Pricing Model at 100% of the value of the credit, arguing that obtaining the third-party tax equity investment is an extremely complex and expensive endeavor. The IPA notes that reducing the level of the ITC would increase REC prices by approximately \$5 - 7 per REC, and therefore it is not an insignificant request. No other party has raised an objection related to the cost of obtaining the ITC, and the Agency notes that there are costs (or at a minimum, opportunity costs and the time value of money) that come along with obtaining every rebate, incentive, tax credit, net metering credit, or other payment that can offset the cost of solar development. For the IPA to begin adjusting for the costs that feed into obtaining a credit

within the REC Pricing Model is a slippery slope that will lead to an increasingly fraught and complex system of developing REC prices. Accordingly, the IPA urges the Commission to reject this objection. IPA Resp. at 69-70.

The JSPs also raise the issue of an investigation opened by the U.S. Department of Commerce into alleged circumvention of antidumping and countervailing duties by solar manufacturers, brought forth by a petition from a U.S. solar panel manufacturer. The Agency agrees that the impact of potential tariffs arising from the investigation is significant and would have major impacts upon the growth and development of the solar market. The IPA believes that it is premature at this time to speculate on the level of the potential tariffs, whether such tariffs would be applied retroactively, and what the cost impact of adjusting for those tariffs on a dollar-for-dollar basis would be to the RPS budget. Accordingly, the Agency suggests a more reasonable approach would be to continue to monitor the situation and the outcome of the investigation. Should additional tariffs be imposed, the IPA can address the matter through the development of the next annual REC Pricing Update, through the utilization of the Agency's discretion to modify REC prices up to 10% between plans, or—and only if those means prove entirely inadequate—through reopening. IPA Resp. at 70-71.

The Joint Solar Parties discovered that several cost categories for community solar pricing in the REC Pricing Model inadvertently contained an incorrect reference, resulting in the undercounting of the costs to build community solar systems. The IPA reviewed the REC Pricing Model and confirmed the existence of this error. The Agency has made technical corrections to the spreadsheet already, and this change will be reflected in the final version of Appendix E published in compliance with the Commission's Final Order approving this Plan. IPA Resp. at 71-72.

Throughout April 2022, the IPA notes, wholesale energy markets featured higher and more volatile energy and capacity prices. The Agency is cognizant of these rising prices and ongoing volatility and plans to update the REC Pricing Model following Commission approval of its Plan, including an update of the inputs for electricity and capacity prices. Those updated inputs, in turn, will have an impact upon REC prices. IPA Rep. at 38.

Recent increases in capacity prices have caused the IPA to consider whether a five-year historical average should likewise be used for capacity prices within the REC Pricing Model. The IPA appreciates that the increases in energy and capacity prices make the value proposition for solar more attractive; however, without averaging, sharp increases in capacity prices—such as those observed this spring—could make REC prices fluctuate unpredictably, which may be unfavorable for market stability. With the Agency's move to annual REC price updates, reliance on a five-year average will help smooth out annual changes to REC Prices due to spikes in electricity and capacity market pricing, providing more consistent, transparent, and reliable REC prices to developers, customers, and other market participants. The IPA believes that utilization of this approach will provide valuable consistency to the annual REC pricing updates. IPA Rep. at 38-39.

To effectuate this approach, the Agency proposes adjusting the calculation for inputs to the REC Pricing Model across programs and categories. For those systems

modeled on the 10 kW system size (residential DG and ILSFA DG), the Agency proposes to use a five-year historical, seasonally-weighted averaged purchased electricity charge specific to Groups A and B. For non-residential systems, the IPA proposes to use five-year historical capacity charges, and would issue discovery to Ameren to provide a service territory-specific peak load contribution for use in developing the Group A inputs. IPA Rep. at 39.

The Agency understands that the proposal to adjust the calculation of certain inputs to the REC Pricing Model is being provided during Reply Comments, but it is necessitated by changes in fact and circumstances. As noted above, this proposed REC Pricing Model adjustment is intended to reduce fluctuations in REC prices resultant from recent energy and capacity price volatility. IPA Rep. at 39.

9. Commission Analysis and Conclusion

With respect to ComEd's proposal, the Commission notes that the IPA states that changes to the REC Pricing Model to create separate REC prices for owned and leased systems has no significant impact on the difference in prices between the two, but the removal of the bonus depreciation for projects 10 kW and smaller significantly increases the REC prices for those systems. This then leads to the opposite result of favoring the purchase of systems rather than leasing. The Commission understands this to mean that without a differentiation between owned and leased systems, the REC Pricing Model is incorrect for either one model or the other depending on how bonus depreciation is treated. The Commission agrees with ComEd that this is inappropriate but relies on the IPA's assertion that the price difference between owned and leased systems, if separated, is not significant. Thus, the Commission finds that, although this proposal is not adopted in this proceeding, the IPA should consider incorporating it prior to the next LTRRPP update.

The Commission finds that the record is not clear whether the JSPs are correct regarding the assumptions made in the REC Pricing Model for the transmission and capacity credits, but it is clear that it would be a large undertaking that would impact multiple parts of the REC model. The Commission agrees with the IPA that this should be reviewed prior to the next LTRRPP update and parties should further discuss the JSPs' claims to ensure that the REC Pricing Model accurately reflects the transmission and capacity credits.

The Commission agrees with the JSPs that the potential tariffs could markedly change the cost of solar systems, and this should be accurately reflected in the REC Pricing Model. As noted by the IPA, there are several routes to update the REC Pricing Model if the tariffs are imposed. First, the REC Pricing Model will be updated one more time before the IPA makes its compliance filing in this docket. The Commission agrees that if the tariffs are imposed before this filing, the REC Pricing Model should reflect this. Also, the IPA can impose a 10% change on REC prices without Commission approval. The Commission finds that reflecting the tariffs is a valid use of that discretion. Subsequent to the filing of Replies to Responses, the President of the United States took executive action to allow for the temporary duty-free importation of solar cells and modules for the next 24 months. As a result, no changes are needed to the REC Pricing Model to account for additional international trade tariffs. The IPA shall consider the

imposition of future trade tariffs on solar cells and modules in its next update of the LTRRPP.

The Commission notes that the Joint NGOs propose that REC prices be more reflective of market signals. Section 1-75(c)(1)(K) includes a requirement that:

The Adjustable Block program shall be generally designed to provide for the steady, predictable, and sustainable growth of new solar photovoltaic development in Illinois. To this end, the Adjustable Block program shall provide a transparent annual schedule of prices and quantities to enable the photovoltaic market to scale up and for renewable energy credit prices to adjust at a predictable rate over time. The prices set by the Adjustable Block program can be reflected as a set value or as the product of a formula.

20 ILCS 3855/1-75(c)(1)(K). The Commission does not find that this statutory language supports either market-based or cost-based prices. It merely requires that the ABP provide an annual schedule of prices and quantities; it does not specify how those prices should be set.

The Commission agrees with the IPA's approach for this LTRRPP, that if market data shows that the IPA's cost-based price is incorrect – either through under- or over-subscription - then an examination of the assumptions for that particular category is appropriate. The Commission looks forward to reviewing the recommendations of the IPA's independent expert consultant on how to develop administratively-set REC prices that both efficiently invest ratepayer funds in renewables and respond annually to changing market conditions.

With respect to bonus depreciation, it appears that this matter is settled between the IPA and the JSPs. The Commission sees that ComEd is still in opposition to the JSPs' proposal and ComEd argues that the REC Pricing Model does not take into account other minor timing effects that would also impact the values. The Commission does not agree with ComEd's reasoning because the JSPs' proposal is a reasonable adjustment that properly recognizes the tax benefits that will be in effect at the time the systems are placed into service.

The Commission notes that the JSPs want to reduce the value that is assumed for the ITC in the REC Pricing Model. Reducing the value of the credit results in an increased REC price. The JSPs assert that because it takes a certain level of investment to just receive the ITC, the value in the REC Pricing Model should be reduced from 100% of the ITC. The Commission agrees with the IPA that it would be inappropriate for the IPA to adjust for the costs that feed into obtaining a credit within the REC Pricing Model. The JSPs' proposal is not adopted.

The JSPs' argument that the component price information utilized by the IPA should be rejected is not adopted. The Commission finds that reliance on the first quarter 2020 NREL data is reasonable and is adopted. It appears that NREL has not yet published a full update to the benchmarking report, the Commission accepts the IPA's representation that a January 2022 NREL presentation shows that photovoltaic system

prices were relatively flat in 2021, despite supply chain shortages and component price increases. IPA Resp. at 63-64. The Commission also notes that the Joint NGOs in Reply Comments state that the IPA's approach of updating assumptions with a recent presentation by NREL is reasonable and in Response Comments supported the use of a discretionary adjustment to modeled cost components consistent with the Wood Mackenzie study. The Commission approves the IPA's decision to remove the 4% downward cost assumption in recognition of the recent changes in costs. The Commission agrees with the Joint NGOs' observation that the difficulty of accessing current, highly sensitive commercial information is one of the limitations of the cost-based model.

The Commission notes that the IPA has made a correction to the REC Pricing Model for Non-Profit and Public Facilities in response to the Joint NGOs' Objections. The IPA notes that the proposed REC prices in its initial filed Plan dropped more than any other ABP category or ILSFA subcategory. The Commission agrees that this adjustment is appropriate. The Joint NGOs also complain that generally the prices are too low in the Non-Profit and Public Facilities categories but do not make any specific recommendations for the REC Pricing Model. The Commission is reluctant to direct the IPA to make changes based on the Joint NGOs' claims without further support.

The following issues appear to be settled: the JSPs' technical corrections; 5 MW development costs; and the 4% downward adjustment. The Commission appreciates the efforts of parties to reach agreement and recognize the validity of the positions of other parties. The agreed resolutions are adopted.

Recently filed price increases were addressed in Reply Comments by the JSPs, ComEd, Ameren, and the IPA. The Commission finds that the IPA's proposal to rely upon a five-year average of electricity and capacity costs in order to help smooth out annual changes to REC prices that may result from spikes in electricity and capacity market prices will provide more consistent, transparent and reliable REC prices to developers, customers, and market participants. It is therefore adopted. The Commission notes that Ameren, in its RBOE states that it does not object to the IPA's proposal but that it recommends that the Commission require the IPA to use a future projection. Ameren RBOE at 3. The Commission does not adopt this proposal because no party has had an opportunity to respond and projections are frequently not accurate.

G. Section 7.5.2 Modeling Update

1. Joint Solar Parties' Position

Currently, the IPA REC Pricing Model treats 500-2,000 kW systems as a single category and over 2,000-5,000 kW systems as a single category. The Joint Solar Parties note that the diversity in these system size ranges - particularly within the 500-2,000 kW category - disincentivizes smaller systems. The Joint Solar Parties thus recommend the following breakdown: 500-1,000 kW, over 1,000-3,000 kW, and over 3,000-5,000 kW. This would provide better incentives for 500-1,000 kW systems because the REC Pricing Model would better reflect their costs while splitting the 4,000 kW between 1,000 and 5,000 evenly. The Joint Solar Parties recommend that at minimum the IPA consider changing the sizing for the 2023-2024 delivery year. JSPs Obj. at 38.

2. Commission Analysis and Conclusion

The Commission agrees that the 500-2000 kW represents a diverse set of systems and could disincentivize smaller systems. In its BOE, the IPA explains that the proposed changes, under the current model, would create a lower REC price for projects in the range of 500-1,000 kW systems than those in the range of 1,000-3,000 kW, and further disincentivize smaller systems. Thus, the Commission agrees with the IPA's proposal in its BOE to explore the use of an additional category to represent smaller systems in the next REC Pricing Model update.

H. Section 7.5.6 Community Solar

1. Arcadia's Position

Arcadia notes that the IPA suggests reducing small subscriber adders as a result of theoretical cost savings associated with online marketing and enrollment processes. Arcadia objects to a reduction of small subscriber adders in the LTRRPP. At this stage, any assumption that online marketing and enrollment results in cost-saving to community solar providers is premature and unsupported by empirical data. Arcadia Obj. at 3.

First, Arcadia is unaware of any data that online marketing provides cost savings over more traditional marketing channels. Possible cost savings is an assumption that may not be reflected in the actual market. Use of online marketing by community solar involves substantial upfront programming costs to navigate and comply with marketing requirements and the relatively complex and technical enrollment process mandated by the LTRRPP. Arcadia Obj. at 3-4.

Second, Arcadia argues that it would be premature for the IPA to make any recommendation that favors one marketing channel over another. P.A. 102-0662 focuses on increasing equity and access to clean energy in the State. It is not yet known how different segments of Illinois' diverse range of customers will respond to different types of marketing. Arcadia has anecdotally observed that low- and medium-income customers may be less responsive to online marketing. Arcadia Obj. at 4.

Third, Illinois has a relatively complex enrollment process that requires each customer to sign an individual Disclosure Form. This process can be challenging when exclusively using online marketing, so the midpoint range of costs may not be an accurate reflection of the true cost of acquiring customers via online marketing in Illinois. The LTRRPP also cites Minnesota's residential adder as similar to the one the IPA proposes for Illinois. Arcadia would caution against comparisons across states on this particular issue, as all community solar programs have unique elements that make "apples-to-apples" comparisons on costs quite difficult. Arcadia Obj. at 4.

2. IPA's Position

The IPA explains that the enactment of P.A. 102-0662 requires all community solar projects under the ABP to have a minimum of 50% small subscribers. This change in law, when viewed with additional data that indicated that REC prices were likely too high for community solar, led the IPA to adjust the small subscriber adder downward. In response to Arcadia's suggestion that the inputs on community solar may underestimate the costs of acquiring small subscribers, the IPA states it is contrary to the data points referenced in the plan. Additionally, if costs for acquisition of small subscribers were

insufficient as included in the REC Pricing Model, the IPA would expect to see low numbers of participants within the small subscriber range (that is, residential and small commercial customers with subscriptions below 25 kW). Program data, however, demonstrate that acquisition of and participation by small subscribers is robust. The IPA notes that the significant waitlist for community solar led the Commission once already to conclude that REC prices were likely too high for this category, and the Agency feels strongly that the data on small subscribers further demonstrates that this is an area in which the pricing has not yet been quite right-sized. The proposal set forth by the Agency in its Filed Plan reflects a reasoned approach to small subscriber acquisition based on the experience in managing the Program, independent research on the costs of small subscriber acquisition, and data from other Midwestern community solar incentive programs. Accordingly, Arcadia's arguments should be rejected, and the Agency's proposed changes to the small subscriber adder should be adopted. IPA Resp. at 72-73.

3. Commission Analysis and Conclusion

The Commission does not adopt the proposal of Arcadia. The Commission agrees that each individual cost that is assumed in the REC Pricing Model might not be completely accurate, but the price set for community solar is clearly sufficient based on the over-subscription of this category.

I. Section 7.9.1 Technical System Requirements

1. Joint Solar Parties' Position

Since the beginning of the ABP, systems over 25 kW have required a signed Interconnection Agreement ("ICA") to apply to the ABP. The JSPs assert that this is because interconnection is frequently a fatal flaw in development and having a signed ICA requires the developer to have gone through requisite studies and not only received a non-binding cost estimate but also a reserved place in the interconnection queue. While a particular system may have "contingent" scope or cost - meaning that a system with an earlier queue position is anticipated to pay for upgrades that the later system relies on for its estimated scope and cost - going through this process, generally speaking, provides clarity and reasonable assurances that a project is viable. JSPs Obj. at 20-21.

The Joint Solar Parties respectfully submit that while there were historic issues with the interconnection queue and community solar systems, a closer look demonstrates that the issues were driven not by the signed ICA requirement but unique and avoidable program issues. The first aspect was that the solar industry, eager to deploy capital to the exciting new Illinois market and take advantage of the new community solar program, invested tremendous resources in Illinois to secure site control, permits, and interconnection rights for the chance to take part in the inaugural ABP. The second aspect was the Commission approved a project selection process for community solar whereby systems would be chosen by a random lottery as opposed to application date or project maturity (such as interconnection queue position). *See III. Power Agency, Docket No. 17-0838, Final Order at 68 (Apr. 3, 2018)*. The third aspect was that, in trying to find the right balance, the ABP initially proposed allowing developers to switch selected projects with others in their portfolio. Meaning, a project that met the minimum application requirements that was unlikely to proceed for whatever reason (including excessive

interconnection costs) had great value because if it was selected, the developer could swap it out for a project that was anticipated to go forward. JSPs Obj. at 21-22.

Based on a confluence of these events, among others, ComEd and Ameren faced substantial issues with their interconnection queues. These issues began well before the initial lottery—ComEd sought two waivers before the Commission and Ameren similarly made accommodations—and continued well after the lottery. Hundreds of community solar projects were restudied for new interconnection costs while the IPA also made alterations to the ABP to accommodate the restudies. JSPs Obj. at 23.

The Joint Solar Parties believe that the correct lesson from this experience is the harm caused by having a selection process based on factors other than first come/first served and project maturity, especially when eligible projects build up. The main issues caused by the original opening were that projects that either had poor interconnection costs or unreliable costs (because the estimates by necessity relied on so many contingencies from projects ahead in the queue) happened to be selected by the random lottery. The lottery could not distinguish the maturity of a project; a well-developed project or a project that barely met the minimum requirements. JSPs Obj. at 23.

The Joint Solar Parties note that several conditions are not the same as the initial lottery. First and foremost, the Commission released a Second Notice Rule in Docket No. 20-0700 which, if adopted, would require a 100% deposit of the non-binding interconnection cost estimate within 15 business days of the interconnection customer signing the ICA. See *Ill. Commerce Comm'n On Its Own Motion*, Docket No. 20-0700, Second Notice Order App. A at 85 (Mar. 23, 2022). In addition, waivers sought by ComEd to allow extension of certain deadlines to provide an ICA for countersignature and to subsequently restudy projects is no longer in effect. See Docket No. 18-1583, Final Order at 14 (Dec. 4, 2018); JSPs Obj. at 23-24.

If signed ICAs are removed as a program requirement, the Joint Solar Parties expect the same or more chaos in the interconnection queues to proceed as developers are selected independently of their position in the queue or the viability of their interconnection. Because a project need not even apply and reserve a spot in the interconnection queue, there is no guarantee that it will have a viable interconnection price or a pathway to development given construction schedules from projects earlier in the queue. JSPs Obj. at 24.

The Joint Solar Parties argue that, while many developers can and will at least apply for interconnection (if not receive a signed ICA) prior to application, those projects will be in competition with wildcat development. This is particularly the case in Ameren's territory, where the Joint Solar Parties understand some areas have no land use permit requirements. The Joint Solar Parties fear this approach will lead to more failed projects which will delay delivery of RECs in satisfaction of the statutory goals in Section 1-75(c)(1)(C) of the IPA Act. JSPs Obj. at 24.

Further, eliminating the requirement for an ICA would not meaningfully address utilities' concerns about costs. As an initial matter, the claim that requiring signed ICAs led utilities to incur significant costs is erroneous. Applicants pay significant fees for interconnection studies, meaning the utilities did not and do not shoulder those costs. Further, eliminating the requirement for an ICA does not mean that developers will stop

filing interconnection applications. In the JSPs opinion, interconnection costs are one of the primary reasons projects do not move forward, and prudent developers understand that completing the relevant studies will give a much better view of project viability before applying to the program. As such, the utilities could see a somewhat reduced volume of interconnection applications compared to the total number of program applicants, but it would not likely result in a significant reduction. JSPs Obj. at 24-25.

The Joint Solar Parties note that, to highlight the importance (and prevalence) of ICAs as a maturity requirement, most major markets around the country have required one in order to apply into the state's community solar program. States that do not require them typically have a different program application structure or have experienced significant challenges due to the lack of requirement. JSPs Obj. at 25.

The Joint Solar Parties also disagree with the IPA's contention that community solar ICAs are not a valid indicator of project maturity because the cost estimates might not be accurate depending on the behavior of projects ahead in queue. The Joint Solar Parties first note that under a true first-come/first-served system, projects earlier in queue are generally speaking likely to apply earlier as well. Even ignoring that potential effect, the IPA's analysis ignores two important aspects of an ICA: it ignores the value of having a place in the interconnection queue, rather than a speculative future position and even a cost estimate that depends on behavior of entities ahead in queue must include information about contingent upgrades so the interconnection customer can estimate the cost effects of systems ahead in queue going forward or not. JSPs Obj. at 25.

If signed ICAs are not required, the Joint Solar Parties unfortunately foresee another chaotic process unfolding for community solar. Removing the signed ICA requirement would add significant risk to the application process and allow speculative projects to apply into the program alongside more mature projects that have already received ICAs and know they can move forward. These speculative projects could take up capacity for many months to years before they ultimately have to drop off the waitlist out of the queue. The JSPs suggest that the utilities would likely need to seek waivers for Commission approval to realign the program queue completely divorced from the interconnection queue. The JSPs urge that a signed ICA be required for program application. JSPs Obj. at 26.

The JSPs assert that ComEd's entire argument appears to be predicated on the incorrect notion that if the IPA removes the requirement for a signed ICA, ComEd's interconnection queue will remain clear of all projects except for those that are selected. ComEd provides no basis for that assumption, especially given the substantial risk that ComEd itself acknowledges with its interconnection process. If a feeder has limited hosting capacity, it may be that the feeder has less hosting capacity than awarded projects on that feeder (especially as now both behind-the-meter and community solar projects may be up to 5,000 kW). JSP Resp. at 9.

The JSPs note that ComEd argues that because less than 5% of those community solar systems that ComEd has processed for ICAs have proceeded to completion, an ICA is a poor measure of project maturity. The JSPs point out that ComEd notably does not include any statistics in the record about the percentage of those projects that won an ABP award, or those that are still progressing toward full interconnection. ComEd ignores

the fact that an ICA is required to operate a system and that waiting until a system is selected puts the system at the mercy of other systems (both that won awards and that did not). JSP Resp. at 9.

ComEd laments that requiring a signed ICA is a poor use of utility resources and customer-supplied funds. The reason ComEd is concerned about utility resources is unclear to the Joint Solar Parties, given that ComEd can and does recover its costs from the applicant under Part 466. See, e.g., 83 Ill. Adm. Code 466.App. E ¶ 10; 466.App. F ¶ 9; 466.App. G ¶ 8. To the contrary - despite the costs associated with proceeding to an ICA for over 25 kW systems, the solar industry believes it is not only a prudent investment but an important program requirement. JSP Resp. at 9-10.

2. ComEd's Position

ComEd states that it appreciates that the Plan reflects some progress on the issue by eliminating the ICA requirement for community supply projects, but it is unclear to ComEd why this revision is limited to community supply projects. ComEd states that its experience overwhelmingly indicates that the executed ICA requirement is not an accurate indicator of a project's maturity. While ComEd uses community supply projects as an example of the lack of correlation between executed ICAs and project readiness, this same takeaway equally applies outside of the community supply project context. ComEd notes that the IPA claims that it continues to believe that an ICA is an appropriate marker of project maturity for DG systems over 25 kW, it offers no evidence to support this contention. ComEd further notes that the IPA does not require ICAs for utility-scale procurements. ComEd respectfully submits that its own day-to-day experience and observations regarding ICAs demonstrate that executed ICAs do not bear a relation to project readiness, and accordingly no evidence supports retaining the executed ICA requirement for all systems over 25 kW. ComEd Obj. at 15-16.

Second, given that an executed ICA does not guarantee project maturity, the continued imposition of this requirement is a poor use of utility resources and customer-supplied funds. To be sure, this prerequisite mandates that electric utilities commit substantial resources, and incur significant costs, related to the processing of thousands of ICAs – and, correspondingly, conducting studies on thousands of speculative interconnection requests necessary to produce the ICAs – despite the fact that a small percentage of such projects successfully interconnect to the utility's system. For example, ComEd has processed nearly 1,200 community supply ICAs since 2017, but less than 5% of the projects associated with these ICAs have proceeded to completion and interconnection to the grid. Each of those ICAs required between one and four interconnection studies to produce them.

Third, it must be underscored that the value of the ICAs is limited – and erodes over time – due to the constantly changing nature of the interconnection queue. By way of background, the ability of a distributed energy resource to interconnect to the distribution system is limited by available hosting capacity at the location of the proposed interconnection and at the time of the proposed interconnection. Because the interconnection rules require that the utility assign 100% of the interconnection costs to each individual project (83 Ill. Adm. Code 466, 467), costs are assigned based on the queue position of the project and are not shared. As a result, a project with the first queue

position may require certain upgrades to the distribution system while the project in the second queue position may not (and the reverse may also be true). Moreover, every time the projects in the queue change (e.g., a project withdraws or a project moves forward), the utility must perform “restudies” to re-estimate interconnection costs. This fluidity of the queue leads to substantial unpredictability, and the cost estimates identified in an ICA can thus become irrelevant as the queue changes. ComEd Obj. at 16-17.

Based on the most recent data as of April 26, 2022, ComEd has tendered 692 CS ICAs since 2017, but only 66 projects have successfully interconnected to ComEd’s distribution system. In other words, less than 10% of the projects associated with these ICAs proceeded to completion and interconnection to the grid. These results show that an executed ICA is not an indicia of project maturity. ComEd Resp. at 10-11.

For these reasons, ComEd recommends that the IPA revise the Plan to fully eliminate the requirement that an executed ICA be included with an application. Reducing the number of interconnection applications from uncertain projects facilitates orderly processing of interconnection requests and protects the rights of interconnection customers who wish to proceed. ComEd Obj. at 17.

ComEd notes that, while the JSPs contend that the costs of these inefficient processes, studies, and restudies are paid through applicants’ interconnection fees (and thus should be of no concern to ComEd), this misses the point. ComEd points out that the elimination of signed ICA requirement from the IPA’s ABP process does not preclude a developer from submitting an interconnection application and proceeding to an executed ICA. Regardless of the recovery of the costs associated with the ICA requirement, the requirement’s impacts clearly disrupt and harm the interconnection process and create a less than desirable experience for those participants in the interconnection queue. Therefore, it should be eliminated. ComEd Resp. at 11-12.

3. Ameren’s Position

In response to the Joint Solar Parties, Ameren notes that there is one factor that is far more critical to a renewable project’s development - the REC incentives offered through the IPA’s ABP. For evidence of this dynamic, Ameren points to the original community solar lottery when over 780 signed ICAs were entered into between Ameren and community solar developers. Of those 780, all of which underwent the study and estimate process referenced by the Joint Solar Parties and resulted in identifying the place in line for the respective project, Ameren states that only 34 moved to completion. Ameren explains that only those 34 projects received REC funding through the IPA’s ABP. Ameren Resp. at 4-5.

Additionally, the Joint Solar Parties assert that eliminating the requirement for an ICA would not meaningfully address utilities’ concerns about costs. Ameren disagrees with this assertion because the Joint Solar Parties err in their assumption that the costs incurred by utilities for projects that do not materialize are the main driver in Ameren’s objection to the signed ICA requirement for community solar facilities. Ameren and the Joint Solar Parties share the same goal of not repeating past practices that led to developer uncertainty about project funding and viability. While the Joint Solar Parties assert that the shortened timeframe for providing a project construction deposit provided under the pending interconnection rules helps fix the dynamics that led to the initial

uncertainties and cost concerns, Ameren notes that the timeframe does not alleviate the real cause of developer uncertainty which is the sequencing of when a developer knows whether they will receive the REC funding that is literally critical for the project to be developed, and when they are required to provide the 100% deposit to the utility for project construction costs. Ameren Resp. at 5.

Moreover, Ameren points out that developers have other tools to gain a preliminary understanding of interconnection costs for sites like the pre-application process available through Section 466.45 of the Interconnection Rules, and the hosting map that Ameren will be required to develop pursuant to the proposed rules in the Commission's Second Notice Order in Docket No. 20-0700. Ameren requests that the Commission not change the draft requirement to not require a signed ICA before a community solar developer applies for RECs through the ABP. Ameren Resp. at 5-6.

4. Staff's Position

Staff notes that ComEd objects to the Plan for removing an ICA requirement for just community supply projects and not all ABP categories. Staff notes that one reason that ComEd gives for removing the requirement for all projects and not just community solar projects is that its own experience with ICAs is that they are not an indicator of a project's maturity. Staff supports ComEd's rationale. Staff Resp. at 18.

5. IPA's Position

ComEd urges the ICA requirement to be dropped for all projects, while the Joint Solar Parties request the ICA requirement to be reinstated for applicant community solar projects. IPA Resp. at 73.

The IPA points out that ICAs have been required as part of the Part I project application for all projects above 25 kW in size since the first LTRRPP filed with the Commission in 2017. The IPA explains that Part I is the initial application for a REC delivery contract, and Part II is the downstream application made by an already-selected REC delivery contract to demonstrate that project's energization and thus eligibility for REC delivery contract payments. The IPA's proposal would remove the ICA requirement from Part I but maintain that requirement for Part II. In originally proposing that requirement, the IPA's hope was that the necessity of an ICA would ensure a baseline level of project maturity. IPA Resp. at 73-74.

In practice, however, obtaining an ICA has not been a useful proxy for project maturity. With no barriers to obtaining an agreement, it has instead merely been a procedural demonstration of someone getting into a line. The estimated interconnection costs found in ICAs have had little value in understanding actual project development economics given the contingencies present in those estimates. Of the 111 community solar projects that have received REC delivery contracts to date, only a handful of contracted projects became non-viable due to interconnection-related issues. And only a subset of those projects—if any at all—would have known about that non-viability at the time their ICA was obtained. Thus, for the IPA, the ICA has demonstrated to be of little value in sorting non-viable community solar projects from viable projects. IPA Resp. at 74.

With respect to the JSPs' suggestion that removing the ICA requirement will lead to chaos, the IPA states that this should not be the case. First, unlike with the prior-utilized random selection process, the IPA has proposed for selection based on transparent qualitative criteria providing developers with a clearer understanding of the likelihood of obtaining a REC delivery contract. Thus, unlike with the lottery, where each project had a random chance of selection, a proposed project that would fare poorly on the IPA's proposed criteria or that would be applying late relative to an existing waitlist of projects would have little reason to apply to the program. Second, as ICAs are no longer a project application requirement, a developer would have no reason to enter the interconnection queue until it receives a REC delivery contract. The IPA believes this should generally result in only those projects that receive REC delivery contracts then seeking ICAs. IPA Resp. at 75.

For the IPA, the net value in requiring an ICA from an applicant community solar project is a function of any benefit it provides as a marker of project maturity. The Joint Solar Parties are correct that developers pay fees for interconnection studies, but those fees are needlessly absorbed if the project does not proceed (such as if the project was not selected for a REC delivery contract). Further, a flood of interconnection applications can result in delays for projects that do wish to proceed with development if non-viable projects sit ahead in the interconnection queue. These costs must be balanced against the value of requiring an ICA from an applicant; the Agency has seen little value in that requirement to date. IPA Resp. at 76.

With respect to criteria, the Plan still requires the following: 1) information about the system location, and size; 2) proof of site control and/or host acknowledgement; 3) project-specific estimate of REC production during the delivery term using PV Watts or a similar tool; 4) for DG systems over 25 kW, an ICA signed by both the interconnecting utility and the interconnecting customer; 5) for community solar systems, a Certificate of Completion or Permission to Operate from the interconnecting utility will continue to be required at the Part II application; 6) for ground mounted systems over 250 kW, a land use permit, when applicable, from the authority having jurisdiction over the project, and in the event a land use permit is not applicable, written confirmation that no permit is required must be provided; and 7) for systems that include a battery, a detailed schematic showing that either only solar generated power can be used to charge the battery or that the battery's output does not run through the meter used to measure solar output. It is the IPA's position that it is unlikely that a developer would satisfy each of these criteria absent a genuine intention to develop that project if selected for a REC delivery contract. Further, the Agency believes-and has directly observed-that a project that has satisfied the above criteria but has also entered the interconnection queue to receive an ICA is no more "mature" than one that has not. IPA Rep. at 51-53.

By contrast, ComEd seeks for the ICA-upon-application requirement to also be dropped for DG projects. While the IPA agrees with ComEd that ICAs have not generally been a valid indicator of project maturity, the Agency is unaware of any pattern of DG projects entering into interconnection queues without those projects ultimately progressing to development. The vast majority of waitlisted DG project applications have moved forward successfully after their ABP application. While some project attrition will

likely occur after REC delivery contract approval and before energization, those project failures are unlikely to be the result of a speculative initial application. IPA Resp. at 77.

In support of its position, ComEd mentions conducting studies on thousands of speculative interconnection requests necessary to produce the ICAs and cites that it has processed nearly 1,200 community supply ICAs since 2017, but less than 5% of the projects associated with these ICAs have proceeded to completion and interconnection to the grid. But the IPA points out that all of this data is specific to community solar, and ComEd offers no comparable analysis for DG interconnection requests. ComEd's concerns around queue positions for distribution system upgrades are specific to community solar as well, as queue position considerations and cost restudies are far more specific to non-behind-the-meter projects relying on shared distribution system infrastructure. From the IPA's understanding, the distribution system upgrades for a system structured to directly offset a customer's load are generally more site-specific and far less frequently feature cost contingencies based on other projects in an interconnection queue. IPA Resp. at 77-78.

6. Commission Analysis and Conclusion

ComEd seeks to eliminate the ICA requirement for all projects, while JSPs want the ICA requirement to be reinstated for community solar projects. Based on the most recent data as of April 26, 2022, ComEd states it has tendered 692 community solar ICAs since 2017, but only 66 projects have successfully interconnected to ComEd's distribution system. Ameren provides similar statistics and states that over 780 signed ICAs were entered into between Ameren and community solar developers. Of those 780, all of which underwent the study and estimate process referenced by the Joint Solar Parties and resulted in identifying the place in line for the respective project, Ameren states that only 34 moved to completion. From these numbers, the Commission agrees that for community solar, a signed ICA is not a sign of project readiness.

In support of its position to remove the ICA requirement entirely, ComEd mentions conducting studies on thousands of speculative interconnection requests necessary to produce the ICAs and cites that it has processed nearly 1,200 community supply ICAs since 2017, but less than 5% of the projects associated with these ICAs have proceeded to completion and interconnection to the grid. But the IPA points out that all ComEd's data is specific to community solar, and ComEd offers no comparable analysis for DG interconnection requests. It appears that ICAs are not an issue for categories other than community solar. The Commission does not adopt ComEd's proposed revision to the LTRRPP.

The Commission does not share the JSPs' concerns that speculative community solar projects will reserve a significant percentage of available block capacity. The Commission notes the criteria that the IPA requires a developer to meet, IPA Rep. at 51-53, and the Commission agrees with the IPA it is unlikely that a developer would satisfy each of these criteria absent an intention to develop that project if selected for a REC delivery contract.

J. Section 7.15 Annual Report

1. Arcadia's Position

Arcadia objects to the proposed requirement to include the subscriber turnover rate in annual reports on community solar projects and recommends the subscriber turnover rate be removed from the list of annual report items. As a general matter, Arcadia supports reasonable reporting requirements as a condition of state solar program participation, as the provision of detailed information to the administering agency can lend itself to programmatic improvements and greater transparency. Here, however, Arcadia is concerned that reporting on the subscriber turnover rate for community solar projects will not serve these objectives and may actually undercut P.A. 102-0662's goal of enhancing access to renewables. Arcadia Obj. at 5.

Historically, in Arcadia's experience, people who rent their homes comprise a significant portion of the small subscribers for community solar, and renters tend to move more frequently than homeowners. As such, a community solar project with a renter-heavy subscriber mix will, all things equal, have a higher turnover rate than a project with greater homeowner subscription activity. In Arcadia's experience, the turnover resulting from renter moves is a manageable aspect of community solar. However, because high turnover rates may leave policymakers and regulators with the impression that a project is unstable -- even if the proper management of the project subscriptions demonstrates quite the opposite -- companies may be discouraged from promoting community solar subscriptions to renters. Arcadia Obj. at 6.

Additionally, in Arcadia's experience, low-income customers tend to be more racially diverse and move more frequently between rented residences than do more affluent populations and homeowners. Because the subscriber turnover rate requirement may tend to push projects towards seeking homeownership customers as opposed to renters, it could contribute to an unintentional systematic exclusion of lower-income and more diverse communities from participating in community solar. Ultimately, this hinders one of the overarching purposes of P.A. 102-0662, which is to improve access to renewable energy, particularly among persons who have historically lacked such access, renters included. Arcadia Obj. at 6-7.

Thus, Arcadia recommends that the IPA remove the subscriber turnover rate from the list of items that must be included in annual reports. Arcadia Obj. at 7.

2. Staff's Position

Staff does not support Arcadia's objection. Staff believes the information is useful and should be collected for the reasons set forth in the LTRRPP. Staff Resp. at 14-15.

3. IPA's Position

The IPA does not share Arcadia's concerns with the requirement that Approved Vendors share subscriber turnover information with the IPA in its confidentially-submitted Annual Report. This reasonable reporting requirement is not a significant burden on Approved Vendors and provides the IPA with valuable insight into how the ABP Program is operating. The Agency recognizes that renters make up a large part of the community solar customer base and does not perceive that high turnover rates would be indicative of instability with a project. Rather, the Agency's interest in this data exists in monitoring

ongoing market progress and trends, and that requires the collection of information from direct program participants. The Agency does not see how the mere reporting of subscriber turnover rates to the IPA will encourage Approved Vendors to seek out certain types of community solar subscribers. IPA Resp. at 79.

4. Commission Analysis and Conclusion

The Commission does not adopt Arcadia's position. The information will allow the IPA to make more informed decisions regarding community solar. The Commission does not find that providing more information will compromise community solar projects themselves or the community solar ABP.

VII. CHAPTER 8 ILLINOIS SOLAR FOR ALL

A. Section 8.2.2 Tangible Economic Benefits

1. LVEJO's Position

To advance the new energy sovereignty commitments under P.A. 102-0662, LVEJO notes that the IPA proposes an exception to the no up-front costs standard, namely to allow for nominal up-front subscription costs for community solar cooperatives that facilitate energy sovereignty. LVEJO argues that the lack of specific information in the 2022 Plan regarding the fee cap determination process leaves significant uncertainty. LVEJO asserts that failure to provide this information and to engage with the public on this decision is also contrary to the goals and objectives of ILSFA, P.A. 102-0662, and the IPA Act. LVEJO Obj. at 3-4.

The absence of public participation opportunities regarding the fee cap determination within the 2022 Plan is also concerning to LVEJO. In many other sections of the 2022 Plan, the IPA explicitly mentions that stakeholder engagement opportunities will be forthcoming as programs are finalized and implemented. LVEJO avers that public participation in this situation is particularly important because of complexities in Illinois that the IPA cannot fully understand without engaging residents who have firsthand experience in each area. LVEJO Obj. at 5.

LVEJO adds that participation of ILSFA's target population – low-income and minority individuals and communities – should be the highest priority. A fee cap alone is not enough to address the burden of an up-front cost to community cooperative solar initiatives for many low-income individuals and LVEJO asserts that implementing other safeguards to offset or alleviate the cost of participation to low-income subscribers is crucial to ensure ILSFA's goals are met. LVEJO Obj. at 6.

LVEJO proposes that rather than a one-size-fits-all fee cap, the IPA should make the determination on a case-by-case basis to recognize the reality of complex, diverse communities within Illinois. While the IPA's 2022 Plan promotes uniform results, LVEJO asserts the results are not equitable. LVEJO explains that uniformity provides the same opportunities and resources for all, while equity recognizes that each community has different circumstances and allocates the appropriate resources and opportunities needed to reach an equal outcome. LVEJO Obj. at 6-7.

LVEJO claims that assessing economic conditions in areas served by a community solar initiative would not be unduly burdensome on the IPA. Economic indicators are

already a part of the IPA's designation of Environmental Justice Communities and are readily available through government agencies. While setting a fee cap with consideration of site and community specific income levels would require no more than one extra step in an application process, LVEJO maintains that it would address a significant barrier for the most overburdened or underserved communities, appropriately aligning with the intention of P.A. 102-0662 and ILSFA. LVEJO Obj. at 7-8.

2. Joint NGOs' Position

A key statutory requirement of the ILSFA Program is that it creates "tangible economic benefits" for program participants. 20 ILCS 3855/1-56(b)(2). As detailed in Section 8.2.2 of the Plan, the Agency ensures these tangible economic benefits through two requirements: 1) no up-front cost for program participants (with some narrow exceptions) and 2) immediate savings on energy costs. The Commission has found that, in order to meet the tangible economic benefits requirement of ILSFA, any ongoing cost of participation in the ILSFA Program for a low-income customer must be less than half the modeled savings the customer would see on their electric bill thanks to their solar production. See Docket No. 17-0838, Order at 151; JNGOs Obj. at 14-15.

The Joint NGOs propose to slightly modify this approach such that the modeled savings could come from either solar production or an energy efficiency improvement delivered at the same time. In other words, in order to meet the tangible economic benefits requirement of the program, any ongoing cost of participation would be less than half the modeled savings the customer would see on their electric bill thanks to their clean energy intervention. Practically speaking, this would allow an Approved Vendor to charge ongoing payments for customers that are higher than they would otherwise be able to charge for the solar alone, so long as those payments are offset by additional, reliable energy savings from an energy efficiency intervention. JNGOs Obj. at 15-16.

The Joint NGOs state that this modification would enable Approved Vendors to bundle energy efficiency and solar delivery, making it more feasible to right-size a low-income household's electric load before installing solar. Where feasible, right sizing a building's load prior to installing solar is a best practice. Furthermore, coordinating energy efficiency and solar delivery in this manner is concordant with the statutory directive to "integrate... with existing energy efficiency incentives," even if it goes beyond the integration named in statute by not being limited to energy efficiency incentive programs. 20 ILCS 3855/1-56(b)(2). Finally, allowing energy efficiency into the energy savings requirement in this way neither increases the solar incentive payment to participants - as that is based on solar system production - nor the customers savings experience - customers still take home at least 50% of their energy savings. JNGOs Obj. at 16.

The Joint NGOs appreciate the IPA's recognition of the importance of energy efficiency, including when deployed in advance of a solar energy installation in order to "right size" the system. While the Joint NGOs continue to believe their proposal should be implemented in this Plan, they also appreciate the IPA's willingness to consider the idea and solicit additional stakeholder input, in anticipation of potentially revisiting it in the next Plan. The Joint NGOs hope that such a stakeholder process will help to satisfy ComEd's concerns, as well, and suggest that the energy efficiency stakeholder advisory

group (“SAG”) could be alerted to any opportunities to provide their input to the IPA on this idea. JNGO Rep. at 13-14.

3. Staff’s Position

Staff does not support the JNGOs’ objection. It is Staff’s position that solar projects should provide value on their own to participants. Therefore, bundling should not be permitted to determine whether a project meets the solar savings threshold. Staff Resp. at 20.

4. ComEd’s Position

ComEd cautions that the Joint NGOs’ proposal does not take into account the extensive energy efficiency offerings that are available under the State-mandated energy efficiency programs required by certain of the State’s public utilities. See, e.g., 220 ILCS 5/8-103B. Perhaps most importantly, the Joint NGOs’ proposal has not been presented to SAG, which is comprised of energy efficiency stakeholders and experts representing a variety of interests and market segments. ComEd states that it is imperative that the Joint NGOs’ proposal first be vetted through the SAG to discuss issues associated with market channels, coordination and duplication among State programs, and evaluation of energy savings. Because these issues have not been broached, much less resolved, the proposal is not sufficiently developed to be capable of consideration or adoption in this docket. ComEd Resp. at 13.

ComEd also observes that the General Assembly is well-aware of how to incorporate energy efficiency into the IPA’s planning process, which it previously directed pursuant to Section 16-111.5(b) of the Act. 220 ILCS 5/16-111.5(b). However, the legislature sunset this Section as part of P.A. 99-0906 that became law on June 1, 2017, and to date the General Assembly has not authorized the inclusion of energy efficiency programs within the LTRRPP. As the JNGOs observe, the legislature has only authorized integration with existing energy efficiency initiatives and has not included the offering of new energy efficiency programs and measures through the LTRRPP. As a result, ComEd argues that to the extent the Joint NGOs’ proposal requires the offering of energy efficiency measures through the LTRRPP, it is unclear what statutory authority exists, if any, to support the proposal. ComEd Resp. at 13-14.

5. IPA’s Position

Section 1-56(b)(2) of the IPA Act directs the Agency to “ensure tangible economic benefits flow directly to [ILSFA] program participants” and that the contracts executed under ILSFA provide that “the solar facilities will produce energy and economic benefits, at a level determined by the Agency to be reasonable, for the participating low-income customers.” Section 8.2.2 of the 2022 Long-Term Plan discusses the program design elements of the ILSFA Program that ensure the flow of tangible economic benefits to the low-income customer. Due to the significant barrier that upfront costs pose to low-income consumers, the Agency has determined that any upfront fees or payments would not create “tangible economic benefits” at a reasonable level, and therefore the LTRRPP prohibited any such upfront fees for residential ILSFA participants. IPA Resp. at 79-80.

While the 2022 Long-Term Plan maintains that prohibition on upfront fees, it does add an exception to that general rule. Revisions to Section 1-56(b) enacted by P.A. 102-

0662 require the Agency to “promote energy sovereignty” by reserving a portion of ILSFA funds for projects that lead to “ownership of projects by low-income households, not-for-profit organizations providing services to low-income households, affordable housing owners, community cooperatives, or community-based limited liability companies providing services to low-income households.” 20 ILCS 3855/1-56(b). The currently viable business models for low- and median-income households to own an on-site or community solar installation often require some form of upfront payment, such as a membership fee to join a cooperative that owns a community solar installation. Therefore, the IPA has tried to balance these competing priorities by allowing for limited upfront costs in cases where doing so facilitates energy sovereignty. In such cases, the LTRRPP proposes to establish a cap on upfront fees to further protect the tangible economic benefits offered to low-income participants. IPA Resp. at 80.

LVEJO objects to the Agency’s failure to provide information regarding the process or timeline for the fee cap determination and, based on that omission, infers that IPA does not intend to conduct additional stakeholder engagement for the fee cap determination. The IPA did not intend this interpretation; the Agency had planned, and still does plan, to conduct a stakeholder feedback process to solicit public input on the method of determining such a fee cap, with that feedback process then informing a final determination on a fee cap methodology to be memorialized through the ILSFA Program Manual. IPA Resp. at 80-81.

LVEJO also points to the wide range of median incomes in areas across Illinois and argues that applying a single fee cap to all communities would create inequitable results. The Agency notes that, despite using the term “fee cap” in the singular form, in practice there will not be a single number that limits upfront fees. Community solar subscriptions vary based on household size, annual electricity usage, vendor offers, and other factors. Where a participant wishes to purchase membership in a community solar co-op, those membership fees will also vary depending on the size of a share the participant wishes to buy and their household size, among other things. What the IPA is proposing is a methodology for capping fees, such that those fees are appropriately limited to ensure tangible economic benefits. The Agency acknowledges that this subtlety could be more clearly explained in the Plan and commits to this clarification. IPA Resp. at 81.

However, the Agency also appreciates the potential for inequitable results if local economic conditions of the customer are not taken into account, as outlined by LVEJO. The Agency is willing to consider incorporating the customer’s local area median income into the methodology for setting the fee cap and will include this element in the stakeholder feedback process for further insight. IPA Resp. at 81-82.

A second element of the 2022 Plan’s implementation of the statutory requirement that low-income customers receive “tangible economic benefits” is the limit on any ongoing annual fees or payments to no more than 50% of the annual first year estimated production and/or utility default service net metering value to be received by the customer. This ongoing savings requirement, approved by the Commission in its Order in Docket No. 17-0838, protects against unexpected fees and also ensures that the solar installation provides reliable, sustainable economic benefits to the customer, both immediately and over the life of the resource. IPA Resp. at 82.

In Objections, the Joint NGOs take issue with the IPA's decision not to allow for savings from bundled energy efficiency and solar installation projects to be included in the savings calculation. The IPA agrees that increasing the uptake of energy efficiency measures is an important strategy for lowering energy costs and improving energy equity for low-income customers. The IPA also acknowledges the value of addressing energy efficiency issues before installing a solar generation system, in order to "right-size" the installation. The IPA Act tasks the ILSFA Program Administrator with coordinating ILSFA activities "with entities implementing electric and natural gas income-qualified energy efficiency programs" and directs it to "connect prospective low-income solar customers with any existing deferred maintenance programs." 20 ILCS 3855/1-56(b)(5). ILSFA already provides a Program Resource Guide on utility-administered energy efficiency programs, weatherization assistance programs, and other services aimed at reducing energy inefficiencies in low-income residences. Thus, the Agency supports the policy objective sought by the Joint NGOs. IPA Resp. at 83.

However, at this time, the Agency does not have enough evidence that adopting the bundled approach to modeling savings from projects supported by ILSFA incentives would result in the same level of certainty of "tangible economic benefits" throughout the life of the 15-year contract. Energy bill savings produced by energy efficiency upgrades are often inexact measurements, and the IPA has not studied those savings methodologies sufficiently to be confident in their parity with savings achieved by net-metering from solar generation. Although the incentives would still be based on RECs produced, the higher expected energy savings from the bundled solar and energy efficiency measures would increase the 50% of "tangible benefits" limit on ongoing payments, opening the door for higher fees but less predictable savings as the Joint NGOs acknowledge. The Joint NGOs qualify that potential for augmented fees as contingent upon "additional, reliable energy savings" from the energy efficiency measures, but provide no support for their assertion that cost savings from energy efficiency measures will be equivalently measurable or reliable. IPA Resp. at 83-83.

The IPA is not ruling out eventual support for the bundling of energy efficiency savings with savings from solar adoption for the purpose of meeting the 50% savings requirement under ILSFA - it is simply premature to adopt such a change without fully investigating the risk of abuse and benefits to customers, as well as the interactive effects between REC prices and the separate funding streams available for energy efficiency measures to ensure that there is not double compensation for those measures. Therefore, the Agency proposes to conduct a stakeholder feedback process to better understand the potential business models, identify savings calculation methodologies, and engage interested actors. If the data and feedback suggest there is valuable benefit to low-income customers and a low risk of gaming, the Agency proposes to revisit the option in the next revision of the LTRRPP. IPA Resp. at 84-85.

6. Commission Analysis and Conclusion

Although the Commission agrees with the Joint NGOs that coupling the LTRRPP programs with energy efficiency would be beneficial, the Commission finds that this proposal must be coordinated with the energy efficiency programs run by Ameren and ComEd and presented to SAG. The Commission finds that, as suggested by the IPA,

that this matter is not ready for inclusion in the 2022 Plan, but rather that the IPA should consider its inclusion in the next long-term renewable resources procurement plan.

The Commission approves the IPA's clarification that despite using the term "fee cap" in the singular form, in practice there will not be a single number that limits upfront fees and that what the IPA proposes is a methodology for capping fees, such that those fees are appropriately limited to ensure tangible economic benefits. The Commission notes with approval that the IPA plans to conduct a stakeholder feedback process to solicit public input on the method of determining such a fee cap, with that feedback process then informing a final determination on a fee cap methodology to be memorialized through the ILSFA Program Manual.

B. Section 8.2.4 Energy Sovereignty

1. LVEJO's Position

LVEJO notes that the IPA defines energy sovereignty as "the eligible low-income household or community organization having or being on a defined path to majority or full ownership of the photovoltaic facility." LTRRPP at 221. LVEJO objects to this definition based on the ambiguity of two terms: "ownership" and "photovoltaic facility" and requests these terms be further defined to avoid confusion and delays. It is not clear whether "photovoltaic facility" refers to individual solar systems, larger systems, or even storage. LVEJO Obj. at 10-11.

LVEJO also notes that the IPA Act defines "community ownership" as "an arrangement in which an electric generating facility is, or over time will be, in significant part, owned collectively by members of the community to which an electric generating facility provides benefits; members of that community participate in the decisions regarding the governance, operation, maintenance, and upgrades of and to that facility; and members of that community benefit from regular use of that facility." 20 ILCS 3855/1-75. LVEJO argues that this definition better encourages wealth-building within energy sovereignty. LVEJO requests that the Commission require the IPA to better articulate the terms "photovoltaic facility" and "ownership" within the definition of energy sovereignty to promote actual energy sovereignty as intended under P.A. 102-0662. LVEJO Obj. at 11-12.

2. Joint NGOs' Position

LVEJO's concerns over definitions related to Energy Sovereignty are well-founded, and further clarification of the terms "ownership" and "photovoltaic facility" is needed. JNGO Resp. at 14.

The Agency states that it, in accordance with P.A. 102-0662, must reserve "a portion of [the ILSFA] program for projects that promote energy sovereignty through ownership of projects by low-income households, not for profit organizations providing services to low-income households, affordable housing owners, community cooperatives, or community-based limited liability companies providing services to low-income households." Plan at 233. Energy sovereignty is defined as "the eligible low-income household or community organization having or being on a defined path to majority or full ownership of the photovoltaic facility." JNGO Resp. at 14.

The Joint NGOs are sympathetic to the Agency's desire for a less prescriptive definition that provides more potential for innovative business models. The Joint NGOs therefore support the expanded definition of energy sovereignty provided by the Agency as well as the commitment to conduct a stakeholder feedback process. JNGO Rep. at 14-15.

3. IPA's Position

Section 1-56(b)(2)(A)(i) requires the Agency to reserve "a portion" of ILSFA funding "for projects that promote energy sovereignty through ownership of projects by low-income households, not-for-profit organizations providing services to low-income households, affordable housing owners, community cooperatives, or community-based limited liability companies providing services to low-income households." The IPA Act does not define "energy sovereignty," thus the IPA formulated a definition to guide the application of the concept. In the 2022 Plan, the Agency defines "energy sovereignty" as "the eligible low-income household or community organization having or being on a defined path to majority or full ownership of the photovoltaic facility." IPA Resp. at 85.

As explained in detail in the 2022 Plan, that definition took into account the statutory direction that any projects deemed to promote energy sovereignty should "ensure that local people have control of the project and reap benefits from the project over and above energy bill savings," and the permission to include projects that "promote ownership over time or that involve partial project ownership by communities." The Agency interpreted the concept of "control" to mean "the ability to determine the use and management of the facility, including operations and maintenance, finance and revenues, and other managerial matters." IPA Resp. at 85.

LVEJO objects to the definition of "energy sovereignty" adopted by the Agency as vague, specifically requesting that the Agency further define "ownership" and "photovoltaic facility" as used within the definition of "energy sovereignty." The definition of "energy sovereignty" will provide vital guidance to developers and potential ILSFA participants, as there are myriad models of project ownership structure that offer varied levels of control of the solar resource by the low-income customer. But it is also this potential for innovative business models that motivated the Agency to adopt a less prescriptive definition. IPA Resp. at 86.

At the same time, the Agency agrees with LVEJO that the definition needs protections to ensure that the projects supported through the reserved portion of incentives properly advance the statutory purpose of local control and benefits beyond the bill savings. To work through these nuances, the Agency will conduct a stakeholder feedback process to learn more about the potential models and the concerns of local communities and will incorporate those interests in eligibility guidelines developed for the 25% of each sub-category budget reserved for projects that promote energy sovereignty. IPA Resp. at 86-87.

It is worth making two points of clarification regarding the definition of "ownership" under ILSFA. First, the Agency is not proposing that "ownership" refer to owning only the electricity produced by any solar generation resource, which would be the equivalent of a Power Purchase Agreement. Second, the Agency had sought to allow flexibility for the owner to decide how much responsibility they wished to shoulder regarding the

management and operation of the solar energy resource, recognizing that some low-income owners might actually prefer a model that outsources the day-to-day operation but still allows them final decision-making authority. In further considering points made by LVEJO and the potential for abuse of such flexibility, however, the Agency concludes that the definition included in the 2022 Plan is too broad. Therefore, the IPA proposes an updated version of the definition for “energy sovereignty” that attempts to address the gaps identified by LVEJO and seeks Commission approval of the definition. IPA Resp. at 87-88.

4. Commission Analysis and Conclusion

The Commission adopts the definition of energy sovereignty proposed by the IPA in Response Comments and notes that LVEJO did not file Reply Comments objecting to the proposed definition. Thus, the Commission can only conclude that the definition has addressed the gaps identified by LVEJO and contains appropriate protections to limit potential abuse.

The Commission also approves the IPA’s proposal to conduct a stakeholder feedback process to learn more about the potential models and the concerns of local communities and will incorporate those interests in eligibility guidelines developed for the 25% of each sub-category budget reserved for projects that promote energy sovereignty.

C. Section 8.5.3.4 Program Delivery Pilot

1. Joint NGOs’ Position

The Joint NGOs assert that the Commission should direct the IPA to expand the focus of the delivery pilot program to include Agency and/or Program Administrator involvement, at least as an observer, for the entire project application process. As described in the LTRRPP, the pilot would focus on preliminary customer acquisition through customer recruitment, income verification, site suitability assessment, partnerships with local organizations, and liaisons with job training and placement programs. Approved Vendors would still be responsible for the Disclosure Form as well as the Part I and Part II applications. JNGOs Obj. at 17-18.

The Joint NGOs note that, as described in the Approved Vendor Manual, the pilot would support Approved Vendors through the customer acquisition process, but not through the actual application for the ILSFA program. Further, the Plan states that this program delivery pilot will target small and emerging businesses. The Joint NGOs applaud the Agency taking this important step to pilot program delivery improvements but are concerned that the limited nature of the current proposal may be setting up small and emerging businesses for failure as well as missing out on an important learning opportunity. JNGOs Obj. at 18-19.

While the “soft costs” of customer acquisition have certainly been a hindrance to the growth of the low-income DG subprogram, as the IPA itself acknowledges the project application process may also be an area in need of improvement. By limiting the delivery pilot program to customer acquisition, the IPA misses an opportunity to increase its understanding of issues with the subprogram and potentially sets small and emerging businesses up for, if not failure, significant challenges. For that reason, the Joint NGOs recommend that each participating Approved Vendor in the pilot program is assigned an

Agency and/or Program Administrator representative that stays in touch with the Approved Vendor through the entire project application process including the Disclosure Form as well as Part I and Part II applications. While this representative should not enable Approved Vendors participating in the pilot to circumvent requirements placed on non-participating Approved Vendors, it may be appropriate for the representative to help Approved Vendors navigate the project application, particularly Approved Vendors that are small and emerging businesses. Even more crucially, such observation of the project application process would enable the Agency and its representative to identify and think through solutions for pain points in the project application process. JNGOs Obj. at 19.

The IPA clarified that its involvement will not be limited solely to customer engagement in the pre-application phase, but that the Program Administrator will devote more time to that period. The Joint NGOs support the IPA's desire to better understand issues with customer engagement in the ILSFA DG subprogram. However, by limiting this pilot program to the customer perspective, the IPA misses an opportunity to holistically understand issues with the DG subprogram. Staff express concern that this could lead to the IPA "standing in the place of developers." The Joint NGOs do not intend to ask the IPA to do the job of Approved Vendors. The Joint NGOs maintain, however, that just as the IPA must understand the customer perspective in order to improve the DG subprogram, it must also understand the process from the perspective of Approved Vendors. JNGO Rep. at 16-17.

2. Staff's Position

Staff has concerns about any Plan where the IPA is standing in the place of developers, if that is what the Joint NGOs suggest. For that reason, Staff does not support the JNGOs' objection. Staff Resp. at 20.

Staff has no objection to the IPA's proposed clarification to the Plan as the IPA does not seem to be suggesting that the Program Administrator would be standing in the place of developers. Staff Rep. at 29.

3. LVEJO's Position

LVEJO notes that expanding the delivery pilot program would serve dual purposes of both helping Approved Vendors navigate a complex process that could otherwise be a barrier to entry, as well as serving as an opportunity for the Agency to gather more information about how to improve this process. LVEJO fully supports this proposal and encourages the Agency to continue investigating ways to make it easier for small, emerging Approved Vendors to access the program. LVEJO Resp. at 3.

4. IPA's Position

Since its inception in 2018, the IPA states that the ILSFA Low-Income DG sub-program has been undersubscribed, regularly ending the program year with capacity unfilled and incentives unused. Feedback from grassroots educators, the Program Administrator, and interested stakeholders continues to identify the need for customer education, a lack of trust among low-income residents, and the complexity of the program application as significant barriers to entry for low-income customers who may otherwise benefit from the Low-Income DG sub-program. IPA Resp. at 88.

The IPA notes that P.A. 102-0662 added new language to Section 1-56(b)(2) permitting the Agency to “propose additional programs through the Long-Term Renewable Resources Procurement Plan ... [that] would provide greater benefits to the public health and well-being of low-income residents through also supporting that additional program versus supporting programs already authorized.” 20 ILCS 3855/1-56(b)(2). Considering the less-than-optimal uptake of capacity in the Low-Income DG sub-program, such an “additional program” to support low-income customers in adopting DG could indeed “provide greater benefits” than the existing sub-program. IPA Resp. at 88-89.

In an effort to gather information, and after looking at similar models successfully deployed in other states, the IPA has created a Program Delivery Pilot under this “additional program” authority. The Program Delivery Pilot is designed to both streamline the customer experience and increase the monitoring of community engagement to provide the IPA with more proof points regarding customer decisions to move forward or not with on-site distributed solar generation installations on which to base any future program changes. The Program Delivery Pilot seeks to test a more vertically integrated model for delivering low-income solar generation resources, as has been done in other states. By shifting many of the customer engagement elements of ILSFA DG projects to the Program Administrator, such as community education, job training and trainee placement, and income verification, the IPA intends for this Program Delivery Pilot to create a more efficient and seamless experience for low-income customers and reduce the number of entities they must interact with, which may boost trust in the program. The Program Delivery Pilot also aims to reduce the soft costs for Approved Vendors offering Low-Income on-site DG projects associated with customer acquisition and engagement. IPA Resp. at 89.

In response to the Joint NGOs, the Agency states that it appreciates the Joint NGOs pointing out the potential for misunderstanding this language in the Plan. The IPA does not intend to limit the involvement of the Program Administrator in customer engagement to the pre-application stages, but rather plans for the Program Administrator to devote more support and resources to that time period. That may include additional staff time for attending community events, working one-on-one with potential low-income DG participants to verify income and explain the application process, and developing written resources for those with limited internet access. The Program Administrator will still work with the Approved Vendor and customer to ensure the application process goes smoothly and answer any questions or concerns the customer may have. The IPA proposes to clarify this point when it finalizes the 2022 Plan after Commission approval. IPA Resp. at 90.

In response to Staff, the IPA states that the Program Delivery Pilot does not propose to have the Program Administrator stand in for the solar project developers (Approved Vendors), but rather to assist them with customer recruitment and interaction, as well as reduce the transactional costs for both the Approved Vendor and the customer in navigating the ILSFA application process. The IPA envisions the role of the Program Administrator in this Program Delivery Pilot as that of a facilitator; it will ensure that the potential customer has all the needed information and is qualified to participate. The IPA will then act as a guide to the customer and Approved Vendor throughout the application

process: answering questions, keeping parties informed, and similar functions. The Agency requests that the Commission approve the Program Delivery Pilot as proposed in the LTRRPP, as it will both adequately support customers and Approved Vendors throughout the project application process and keep the role of the Approved Vendor intact. IPA Rep. at 56-57.

5. Commission Analysis and Conclusion

It appears that the IPA's clarification has satisfied the concerns of both Staff and the Joint NGOs. The IPA, in Reply Comments, clarifies that it does indeed intend to also support Approved Vendors and not just consumers, thus appearing to address the remaining concern of the Joint NGOs. Also, it is clear to the Commission that the Program Administrator will not fill the role of the Approved Vendor but will instead assist Approved Vendors with customer recruitment and interaction, as well as reduce the transactional costs for both the Approved Vendor and the customer in navigating the ILSFA application process. The Commission finds the Program Delivery Pilot, as clarified by the IPA in comments, to be a valid proposal to address low enrollment in ILSFA.

D. Section 8.5.5 Low-Income Community Solar Project Initiative

1. Joint Solar Parties' Position

The LTRRPP proposes that all subscribers to Low-Income Community Solar systems selected through ILSFA must receive a utility consolidated bill through "net crediting" as required by Section 16-107.5(l)(4) of the Act. The JSPs complain that ComEd's Commission-approved tariff pays the system owner on the last dollars collected from the customer because the rest are utility fees and if the customer does not pay utility fees the customer would be subject to disconnection. The Joint Solar Parties state there is no dispute that under the "net crediting" tariffs of both utilities, the system owner is only paid to the extent that the customer first pays off all charges for which a customer could be disconnected (which does not include the community solar fee). Second, there is no dispute that if low-income assistance does not cover subscription fees, any customer on assistance is unlikely to pay their subscription fee. Third, if a customer has arrears on their bill, the customer's payment will go first toward utility arrears. JSP Rep. at 38.

Customers on low-income assistance or with arrears clearly are and should be top priorities for the ILSFA program because those customers will benefit most from the bill credit for which they pay a maximum of 50 cents on the dollar. If "net crediting" is required, however, then system owners' collections of subscription fees will almost certainly be locked in at zero—at least while the customer is on assistance or has arrearages. JSP Rep. at 38.

Non-collection of subscription fees is not inherently problematic, the JSPs clarify, as long as the ILSFA REC Pricing Model acknowledges that reality. However, the ILSFA community supply REC Pricing Model assumes that system owners collect 50% of bill credit value. As explained above, 0% of the bill credit value should be the expected collections from customers on low-income assistance (unless of course the low-income assistance covers the subscription fees) and customers with arrearages. The imbalance between revenue expectations and reality provides the perverse incentive to system

owners to try to avoid two of the very groups of customers that would benefit from subscriptions the most. JSP Rep. at 38.

In the alternative, the Low-Income Solar Program should require no bill to customers (i.e. the customer retains 100% of bill credit value) like the Residential 1-4 Unit ILSFA program. JSP Rep. at 39.

2. ComEd's Position

ComEd recommends that the Plan's references to the net crediting provisions in the Act be corrected to refer to Section 16-107.5(l)(4) and not to Section 16-107.5(k)(4). ComEd Obj. at 17.

With respect to the IPA's proposal that subscribers to projects selected by the Low-Income Community Solar Project Initiative must use the net crediting agreement described in Section 16-107.5(l)(4) of the PUA, ComEd notes that the Commission has already approved ComEd's implementation of the net crediting provisions of Section 16-107.5(l)(4). *See generally Commonwealth Edison Co.*, Docket No. 21-0851. While the JSPs nonetheless revisit the complaints they raised and lost in Docket No. 21-0851, they do not attempt to relitigate the issue (which they are foreclosed from doing in any event). As such, ComEd merely notes that the Commission faithfully implemented the net crediting provisions of Section 16-107.5(l)(4) of the PUA, and neither the IPA nor Commission should credit the JSPs' complaints in this docket. ComEd Resp. at 14.

3. Staff's Position

Staff does not support the JSPs' objection. The goal of low-income assistance programs is to prevent low-income customers from having their basic electric service discontinued. If solar system owners are put on the same level as utilities as far as payment, there will be less funds available for low-income customers who choose not to participate in community solar. Less funds means that more customers will have their service discontinued, all else equal. Since utility service is the basic service customers need and subscriptions are not, it is reasonable for the Plan to provide for the net crediting set forth in the Plan. Staff Resp. at 23-24.

Staff agrees with the IPA that net crediting and consolidated billing offer benefits for customers and concurs with the IPA's proposal to review the program in the future to determine if any changes are required. Staff Rep. at 36.

4. IPA's Position

One sub-program within the ILSFA provides incentives for community solar projects to increase the participation of low-income subscribers of community solar projects. The economic benefits for the low-income subscriber take the form of a credit on their utility bill, representing the value of their proportional share of the energy produced by the community solar resource based on the size of their subscription. IPA Resp. at 90.

P.A. 102-0662 introduced a new option for community solar net metering in which the utility will "include a subscriber's subscription fee on the subscriber's monthly electric bill and provide the subscriber with a net credit equivalent to the total bill credit value for that generation period minus the subscription fee, provided the subscription fee is

structured as a fixed percentage of bill credit value.” 220 ILCS 5/16-107.5(l)(2). The IPA explains that this “net crediting” structure allows for “single billing” where the customer receives a credit on their utility bill that has already accounted for their community solar subscription fee. From the customer experience perspective, this option greatly simplifies the customer’s participation and reduces the confusion caused by dual billing. To maximize that benefit to the low-income customer, the IPA’s 2022 Plan requires low-income community solar project developers to elect this single-bill option. IPA Resp. at 91.

Joint Solar Parties object to this requirement, claiming that ComEd’s Commission-approved implementation of the net crediting option will expose community solar project developers to risk of non-payment. The IPA is sympathetic to the Joint Solar Parties’ concerns but note that the benefit to customers of net crediting and single billing is also compelling. As is the case for all ILSFA sub-programs, any ongoing payments, such as regular subscription fees, must be less than 50% of the savings on the low-income customer’s utility bill. Currently, the savings to the customer appear on their utility bills as a net metering credit, but they also then receive a separate bill for any subscription payments, where applicable. Stakeholders have noted that this “dual billing” causes confusion and distrust among low-income customers. IPA Resp. at 91-92.

As such, the IPA proposes to keep the current requirement that low-income community solar projects utilize net crediting but wishes to reserve the right to propose through a stakeholder feedback process making it optional. The IPA will closely monitor activity in the Low-Income Solar sub-category. If the Agency observes community solar developers deciding to forego offering ILSFA Low-Income Community Solar subscriptions due to this enhanced risk of non-payment, the Agency proposes to put out an update to this requirement, making it optional, for stakeholder feedback. IPA Resp. at 92.

ComEd filed an objection to an incorrect citation in Section 8.5.5 of the 2022 Plan. ComEd requests that “the Plan’s references to the net crediting provisions in the PUA be corrected to refer to Section 16-107.5(l)(4) (and not to Section 16-107.5(k)(4)).” The IPA acknowledges this error and agrees to correct the citation. IPA Resp. at 92.

5. Commission Analysis and Conclusion

The Commission notes that it cannot change the utilities’ net-crediting tariffs in this docket. The only question for the Commission’s consideration is whether the LTRRPP is correct to require that low-income community solar project developers elect the single-bill option. The Commission finds that this requirement has the potential to reduce confusion that multiple bills could cause. With the IPA’s assurance that it will monitor activity in the Low-Income Solar sub-category and in particular monitor if developers forego offering ILSFA Low-Income Community Solar subscription due to this requirement, the Commission approves the LTRRPP’s inclusion of this requirement.

E. Section 8.5.6 Incentives for Non-Profits and Public Facilities

1. ComEd’s Position

ComEd notes that the new ABP categories created by P.A. 102-0662 - CDCS, EEC, and Public Schools - are undersubscribed. Since the initial blocks for these categories opened on December 14, 2021, only one application had been submitted in

the ensuing four months that preceded the date on which Objections were filed, and this application was not associated with a public school. JNGOs Obj. at 10-11. While this tepid ABP response is concerning in its own right, this issue is exacerbated by the IPA's proposal to sunset the ability of public schools to participate under the ILSFA after one year. ComEd Resp. at 14-15.

ComEd argues that P.A. 102-0662 did nothing to eliminate, or suggest the sunset of, a public school's option to participate in a program under the ILSFA. Indeed, P.A. 102-0662 did not include any amendments to the ILSFA subprogram through which public schools have previously participated. Section 1-56(b)(2)(C) of the IPA Act continues to provide that "non-profits and public facilities" are eligible to receive incentives for on-site photovoltaic generation. This subprogram is available to eligible public schools, and as the Plan acknowledges, "the higher REC price offered by the [ILSFA] Program can help overcome the financing barriers that certain non-profits and public facilities may face compared to private entities." LTRRPP at 217; ComEd Resp. at 15.

Second, and in contrast to the ILSFA subprogram, ComEd states that the ABP's Public Schools category is targeted only at Tier 1 and 2 public schools, which are defined by the funding needed to educate students within the district based on the evidence-based factors set forth in the Illinois School Code. See 105 ILCS 5/18-8.15(g)(3). In other words, public schools that are located in low-income or Environmental Justice communities – and that do not qualify as a Tier 1 or 2 public school – will no longer have a specific category or program available to them after the IPA's proposed one-year sunset concludes. ComEd Resp. at 15-16.

With respect to the reasons given by the IPA for sunseting the ILSFA public school option, each rationale fails. First, the fact that P.A. 102-0662 created a new ABP category provides no support for the elimination of the separate (and preexisting) ILSFA subprogram available to qualifying public schools. Second, to the extent the IPA is concerned about budget constraints and cutting costs, ComEd suggests that the IPA's focus not begin with vulnerable public schools, which have clearly become a focus of General Assembly support under P.A. 102-0662. For example, the IPA could examine whether it is prudent to spend the maximum 5% budget available for grassroots educational efforts, especially because the IPA seems hard-pressed to find meaningful ways to do so. Finally, with respect to the IPA's perceived concentration of funds on low-income and Environmental Justice communities, ComEd again cautions that this should not serve as a reason to pare back opportunities available to public schools. LTRRPP at 249-250. To the extent the IPA observes an increasing emphasis on, and allocation of funding toward, the State's most vulnerable communities and institutions, ComEd suggests that this is precisely the intent of the General Assembly. This increase in funding should not be used as a rationale for cutting core offerings to vulnerable public institutions like public schools. ComEd Resp. at 16-17.

2. IPA's Position

With the limited exception of allowing the participation of public school projects to participate in the ILSFA Non-Profit and Public Facility sub-program during the 2022-2023 delivery year, the IPA does not support ComEd's proposal, as it would be inconsistent

with the choices of the General Assembly in passing P.A. 102-0662 and would result in duplication across programs. IPA Rep. at 58.

ComEd's proposal would allow public schools to apply projects to both the ABP Public Schools category and the ILSFA Non-Profit and Public Facility sub-program beyond the 2022-2023 delivery year. ComEd argues that these two blocks are "not interchangeable – each program has its own set of criteria and specific REC pricing." That is correct, but the General Assembly was aware of that distinction and chose to create a category devoted to public schools within the ABP - not within ILSFA. The General Assembly could have created a new sub-program in ILSFA for public schools if it believed that those projects required or warranted the REC prices applicable to ILSFA programs; it chose not to do so. Instead, it determined that there was enough interest from public schools in solar energy to merit a reserved block of ABP capacity, and, unlike ILSFA sub-programs, ABP categories guarantee a set amount of capacity, rather than budget. The IPA maintains that it has carried out the General Assembly's chosen program design, as required under P.A. 102-0662. IPA Rep. at 59.

Under ComEd's proposed approach of permanently allowing public schools to apply to either sub-program, it is unclear why any school would choose to apply for the ABP program when the REC price for the ILSFA Non-Profit and Public Facility sub-program is significantly higher. At the same time, the ILSFA Non-Profit and Public Facility sub-program has been traditionally oversubscribed, meaning that many submitted projects do not get funded. If the demand for incentives for projects at public schools is already low, as ComEd seems to argue by pointing to the lag in applications to the ABP Public Schools, it does not make sense to provide more supply by allowing them to apply to two separate programs, especially when doing so would reduce the incentives available for other non-profits and public facilities in an already oversubscribed category. IPA Rep. at 59.

ComEd's second argument in favor of its proposal also fails. ComEd claims that the ABP Public Schools category is "targeted only at Tier 1 and 2 public schools." This is incorrect. Contrary to ComEd's claims, all public schools are eligible to apply to the ABP Public Schools category, as they are now for the ILSFA Non-Profit and Public Facility sub-program. ComEd also claims that "public schools that are located in low-income or environmental justice communities – and that do not qualify as a Tier 1 or 2 public school – will no longer have a specific category or program available to them after the IPA's proposed one-year sunset concludes;" this is also incorrect. ComEd Resp. at 15-16. The ABP Public Schools category will prioritize projects located at schools that are Tier 1, Tier 2, or in an Environmental Justice community, but any project located at a public school is eligible to apply for the Public Schools category. The Plan proposes to allocate 70% of the category capacity to projects at these schools, with the remaining 30% open to all other public schools. IPA Rep. at 60.

Finally, ComEd refers vaguely to IPA concerns about "budget constraints." The IPA notes that budgets for the ILSFA sub-programs are set by statute as a percentage of the total program budget while, as ComEd points out, the statute sets a maximum percentage level of funding for grassroots education. The Agency has historically only awarded about 1.67% of the ILSFA budget to grassroots education. Even if the Agency were to further decrease the amount of ILSFA funds dedicated to grassroots education,

that would have little impact on the available budget for the Non-Profit and Public Facility sub-category, which is set by statute at 25% of the total ILSFA budget. Thus, not only is ComEd's recommendation irrelevant to the question of permitting public schools to participate in ILSFA after the end of the 2022-2023 delivery year, it also does not solve the problem it purports to address. IPA Rep. at 60-61.

The Agency believes that it has appropriately interpreted P.A. 102-0662 in limiting public schools' eligibility to the ABP Public Schools category beginning in the 2023-2024 program year. If that category is unable to meet demand from public schools and the ILSFA Non-Profit Public Facilities sub-program is undersubscribed, the Agency may revisit the issue in its next Plan. At present however, and as highlighted in multiple parties' briefs, the ABP Public Schools category is undersubscribed. Allowing projects that would qualify for this ABP category to participate as public facilities under the ILSFA Program - at a more attractive REC price and payment structure - will risk under-participation in the ABP Public Schools category while also limiting ILSFA awards to other non-profit and public facility projects that do not benefit from a dedicated ABP category. For this reason and the reasons outlined above, the IPA opposes ComEd's proposal and asks the Commission to approve the eligibility requirements for public schools described in the Plan. IPA Rep. at 61-62.

3. Commission Analysis and Conclusion

The IPA clarified that the ABP Public Schools category will prioritize projects located at schools that are Tier 1, Tier 2, or in an Environmental Justice community, but any project located at a public school is eligible to apply for the Public Schools category. ComEd ignores that these schools will be prioritized. Also, the Commission notes that the IPA states that the LTRRPP allocates 70% of the category capacity to projects at these schools, with the remaining 30% open to all other public schools. The Commission finds that the IPA's proposal is a reasonable interpretation of the changes required by P.A. 102-0662.

The Commission further agrees with the IPA's approach to limit public schools' eligibility to the ABP Public Schools category beginning in the 2023-2024 program year and, if that category is unable to meet demand from public schools and the ILSFA Non-Profit Public Facilities sub-program is undersubscribed, the IPA should revisit the issue in its next LTRRPP.

F. Section 8.10.3.2 Determining Income Eligibility

1. Joint Solar Parties' Position

The Joint Solar Parties point out that the current income verification process makes it far more difficult and administratively demanding for a low-income resident to enroll in an ILSFA system than a resident with more resources in an ABP system. The Joint Solar Parties urge the IPA to work with stakeholders on an ongoing basis to identify and remove barriers to income verification. JSPs Obj. at 39.

However, the JSPs aver that some improvements do not need to wait for a stakeholder process. For instance, for low-income community solar projects, the LTRRPP already acknowledges that the transaction costs of proving income eligibility may outweigh the value to the customer when compared to an on-site installation. See

LTRRPP at 267. However, while appreciated, the improvement to income verification for individual residents wishing to subscribe to low-income community solar proposed in the LTRRPP is to qualify some of these residents using a U.S. Department of Housing and Urban Development (“HUD”) Qualified Census Tract (in which at least 50% of households are below 60% of area median income and include a signed affidavit). The Joint Solar Parties recommend expanding eligibility to include census tracts or blocks in which at least 50% of households are below 80% of area median income, because this threshold matches the desired goal of reaching Low and Moderate Income households, as measured by that 80% of area median income definition. The Joint Solar Parties support the requirement that each participating household still provide a signed affidavit to confirm that the household is among those 50% or more of households that fall under that income threshold. JSPs Obj. at 39-40.

The Joint Solar Parties support expanding census tract eligibility (with an affidavit) because it is less intrusive and risky than the other methods that require sharing of Personally Identifiable Information or documentation that may be overly difficult for a resident to collect and share. In other words, it leads to a better customer experience. The Joint Solar Parties and the IPA (as well as other stakeholders) share a common goal of expanding access to the benefits of solar and participation in ILSFA. Expanding census tract eligibility is an important step toward that common goal. JSPs Obj. at 40.

The JSPs note that the IPA proposes addressing the issue in stakeholder groups and potentially proposing it in the next plan. The Joint Solar Parties note that waiting another two years to even address the issue is wasting precious time and creates a drag on the Low-Income Community Solar program, which the IPA concedes has had slow uptake. This docket is the appropriate venue to address the issue, and the Joint Solar Parties recommend that the Commission adopt the Joint Solar Parties’ Objection. JSP Rep. at 39-40.

As an aside, the Joint Solar Parties noted that in response to an Objection from the Joint NGOs in support of attestations, the IPA contended that allowing the Program Administrator to verify income “avoid[s] divulging sensitive information to a commercial entity.” IPA Resp. at 93. Respectfully, the Joint NGOs’ concern - shared by the Joint Solar Parties - is not necessarily just about low-income customers providing sensitive personal information to a “commercial entity” but to any entity, which of course includes the ILSFA Program Administrator. LVEJO appears to agree, focusing not on who receives the information but the process of income verification. The Joint Solar Parties do not object to the Program Administrator offering this service but note it may not convince potential subscribers reticent to provide sensitive information. JSP Rep. at 40.

2. Joint NGOs’ Position

The Joint NGOs explain that customers in the ILSFA program must go through an income verification process and accompanying paperwork to demonstrate that they earn 80% of the area median income or below (the cutoff for eligibility per Section 1-56(b) of the IPA Act). Depending on how income is verified, this can take an inordinate amount of time and require that customers share private information, resulting in a high barrier to participation for some low-income households and potentially deterring these customers from participating in the first place. JNGOs Obj. at 20.

The Joint NGOs explain that self-attestation is a method of verifying income eligibility which allows a customer to sign an affidavit asserting that they, combined with other members of their household, make a certain amount of income annually. This affidavit serves as evidence that a qualifying customer is below the 80% area median income threshold, just as a tax return does. Unlike a tax return, however, this method prevents the customer from having to provide their private and sensitive information to a sales representative or program administration team member. It also does not require that the customer complete a complex form and then wait for the form to be processed before learning whether they are eligible. JNGOs Obj. at 20.

The Agency already uses income self-attestation in two cases. First, the program guidelines allow affidavits for customers who attest that they make zero income. Second, the guidelines allow for potential low-income community solar subscribers to self-attest so long as they reside in a low-income Qualifying Census Tract. These limited pathways for self-attestation could potentially expand to allow additional customers a more dignified option that fosters customer privacy while maintaining fidelity to the program's income requirements. JNGOs Obj. at 20.

Additionally, the Illinois Department of Human Services and Department of Healthcare and Family Services have been accepting self-attestation to verify income since 2020, and it has proven successful in increasing Medicaid participation. The Joint NGOs would encourage the IPA to explore this potential for self-attestation in the energy sector as well, possibly by learning alongside other agencies and departments that are considering using or currently use self-attestation for income verification. JNGOs Obj. at 21.

3. Staff's Position

Staff has no objection to the IPA exploring potential benefits of allowing self-attestation but cautions that any allowance of self-attestation must then have controls in place to prevent developer abuse of that process. Staff Resp. at 20.

4. LVEJO's Position

LVEJO supports the Joint NGOs' objection and recommendations as methods to streamline and ease the application process for low-income residents. LVEJO Resp. at 4. LVEJO is concerned that the current income verification system for low-income community solar customers is overly burdensome and requires the disclosure of sensitive personal information, both of which can deter low-income customers from applying or finishing an already-started application. LVEJO supports the JSPs' proposal for expanding the range of people who are eligible to provide a self-attestation affidavit (rather than the longer process). LVEJO asserts that the JSPs' proposal is a welcome proposal for reducing those barriers for the low-income community solar program's target demographic, which are already heavily burdened. LVEJO supports this proposal as part of its goals of ensuring that solar capacity is distributed in a more equitable manner under P.A. 102-0662 and through the LTRRPP. LVEJO Resp. at 7-8.

5. IPA's Position

Section 1-56(b) of the IPA Act defines "low-income households" as "persons and families whose income does not exceed 80% of area median income, adjusted for family

size and revised every 5 years.” 20 ILCS 3855/1-56(b). The Agency allows customers to demonstrate their income level in several ways, and the options now include: 1) review of most recent federal tax return; 2) income verification through a third-party income verification system; and 3) verification of participation in another low-income energy program, in HUD housing assistance program, or in other benefits programs where the income eligibility limit is 80% of area median income. The Agency allows two additional methods of income verification for low-income community solar, in recognition that the transaction costs of income verification are greater compared to the value of the incentive offered for community solar subscriptions: 1) income verification directly with the Program Administrator, upon request by the subscriber and 2) residence in a HUD Qualified Census Tract and a signed affidavit from the subscriber that they meet the income qualification level. IPA Resp. at 92-93.

The Joint NGOs object to the Agency not allowing self-attestations to qualify as income verification. Joint NGOs claim that signing an “affidavit serves as evidence that a qualifying customer is below the 80% area median income threshold, just as a tax return does.” The Joint NGOs request that the Agency expand the narrow circumstances in which it currently accepts signed affidavits and accept self-attestation without specifying any limitations. The IPA believes it would be premature to introduce such a drastic change to the income verification process before ascertaining whether other interventions might alleviate the concern. IPA Resp. at 93-94.

The Agency understands that the income verification process appears complex but disagrees with the Joint NGOs’ claim that the actions proposed in the LTRRPP are plainly insufficient to reduce this potential barrier to participation in ILSFA sub-programs. The IPA has taken steps to reduce the burden of income verification, including allowing the customer to request that the Program Administrator to perform the verification, having the Program Administrator provide such customers with referrals to Approved Vendors that serve that customer’s area, and providing Approved Vendors with aggregated data on those referral requests so that Approved Vendors can see where the unmet demand is. In the 2022 Plan, the Agency also proposes to reduce transaction costs and simplify the customer experience through the Program Delivery Pilot, discussed above, in which the Program Administrator will provide support and resources to both the Approved Vendor and the customer throughout the project application process. IPA Resp. at 94.

The Agency does accept a signed affidavit as proof of income in two limited circumstances: where the customer claims no income, and where a potential low-income community solar subscriber resides in a Qualified Census Tract—an area where at least 50% of households have an income below 60% of the area median income—as determined by HUD. The IPA has made this narrow exception for income verification because the incentives for low-income community solar are much lower, making the transaction costs of income verification more burdensome in relation to the incentive, and there is high likelihood that residents of a Qualified Census Tract would have an income below 80% of the area median income, as required by ILSFA. Therefore, the Agency proposes that it work with the ILSFA Advisory Group to research the risk of gaming if self-attestation is adopted as a means of income verification and revisit this option in the development of the next Long-Term Plan. IPA Resp. at 94-95.

The IPA notes that the Joint Solar Parties recommend that the IPA expand the option for community solar applicants to verify income by proving residency in a Qualified Census Tract along with a signed affidavit attesting to the household income. Currently, this option requires that the potential subscriber live in a HUD-identified Qualified Census Tract, which means that 50% of the area residents make less than 60% of the area median income. Joint Solar Parties request that the Agency modify this option to allow potential subscribers living in census tracts where at least 50% of the residents have incomes below 80% of the area median income to qualify with only a signed affidavit. IPA Resp. at 95.

The IPA has previously examined this option. For ComEd customers, 43% of all households would fall into such a census tract, compared to only 17% of ComEd households located in a Qualified Census Tract. The IPA explains that adopting the Joint Solar Parties' suggestion would significantly expand the universe of customers that would qualify for this exception, which was narrowly tailored to reduce the likelihood that the potential subscriber does not meet the statutory definition of low-income. The Agency proposes to include in its research and discussions with the ILSFA Advisory Group the option of expanding the exception for low-income community solar applicants to allow self-attestation for potential subscribers that live in an area where at least 50% of the residents make less than 80% of the area median income and will consider proposing that adjustment in the next LTRRPP if the Agency determines that the change is warranted. IPA Resp. at 95-96.

6. Commission Analysis and Conclusion

The Commission notes that the JSPs recommend that the IPA expand the option for community solar applicants to verify income by proving residency in a Qualified Census Tract along with a signed affidavit attesting to the household income. As proposed by the IPA, this option requires that the potential subscriber live in a HUD-identified Qualified Census Tract, which means that 50% of the area residents make less than 60% of the area median income. Joint Solar Parties request that the Agency modify this option to allow potential subscribers living in census tracts where at least 50% of the residents have incomes below 80% of the area median income to qualify with only a signed affidavit. The Commission notes that the IPA proposes to explore this before the next LTRRPP approval process. The Commission finds, however, that because of the low uptake in the low-income category, that the IPA should institute this change now. During the period before the next LTRRPP, the IPA should examine whether it is successful at expanding participation in the program and if there is evidence of abuse of that process. If it is successful, and if there is no evidence of abuse, the IPA should explore the wider use of self-attestation for income verification for residential customers throughout ILSFA subprograms. The IPA should also continue to work with stakeholders on an ongoing basis to identify and remove barriers to income verification.

G. Section 8.11 Consumer Protections

1. Joint NGOs' Position

The Joint NGOs support the IPA's decision to eliminate the seven-day mandatory waiting period between when the Standard Disclosure Form is signed and when the contract can be signed. The Small Residential subprogram of the ILSFA program is

substantially underutilized and has resulted in a multi-year backlog of program funds that should have been deployed to reduce energy burdens and increase solar accessibility. Significant reforms are required, including those that streamline the process for Approved Vendors and reduce customer acquisition costs like the elimination of the required waiting period. While the Joint NGOs support the elimination of the waiting period, the Joint NGOs recognize the importance of consumer protections and appreciate the Objections raised by LVEJO. Instead of eliminating this change altogether, the Joint NGOs propose an alternative route to balance streamlined customer acquisition with customer protections, namely, extending the free contract-cancellation window from the current 14 calendar day period in the proposed plan until the date of system installation. JNGO Resp. at 14-15.

The Joint NGOs further explain that the Small Residential subprogram is lagging in part due to ongoing issues in recruiting and retaining Approved Vendors, who are willing to provide qualifying offers. Participating Approved Vendors have indicated that high customer acquisition costs and administrative burdens make the projects difficult to finance. The IPA acknowledged this in its Plan and has taken steps to improve the customer acquisition process by, for example, requiring that the Program Administrator offer income verification, onboarding qualifying customers from low-income energy efficiency programs, and creating the ILSFA SAG for ongoing troubleshooting. The IPA's proposed elimination of the seven-day mandatory waiting period is another important step, because it reduces the number of trips that an Approved Vendor representative must make to each customer's residence, thereby reducing customer acquisition costs. JNGO Resp. at 15.

To balance reducing customer acquisition costs and consumer protections, the Joint NGOs propose extending the free cancellation period requirements beyond the 14 days as an alternate solution. They suggest maintaining the option for customers to sign the Disclosure Form and contract concurrently but extending that free cancellation window so that the customer can cancel up until the installation day. JNGO Resp. at 16.

2. LVEJO's Position

LVEJO believes that the seven-day waiting period provides a valuable safe harbor for consumers that ensures they have the time to study and understand the contractual obligation they are about to undertake. Under the IPA's proposal, a consumer can sign both documents simultaneously and then, if they change their mind, must take a proactive step to cancel the contract during the 14-day period. LVEJO opines that this creates an unnecessary burden on consumers. LVEJO argues that this proposal also contradicts the statutory requirement that permits the IPA to require program participants to provide standard disclosures "prior to that customer's execution of a contract." LVEJO Obj. at 15.

3. IPA's Position

The IPA explains that, previously, for ILSFA, Approved Vendors and Designees were required to provide a 3-day "cooling off" period between when the customer received and executed a Disclosure Form and when they could then sign a contract. The Agency proposes in this Plan that the cooling off period be eliminated and, instead, the rescission window be extended from 7 to 14 days. IPA Resp. at 121-122.

In the IPA's opinion, a mandatory three-day cooling off period creates a barrier to participation that is not justified by the benefits. Notably, a customer always has the option to simply not sign a contract immediately after signing the Disclosure Form and the Agency's proposal gives the customer the choice as to whether to sign a contract right away or not. IPA acknowledges that high-pressure sales tactics are possible and modified the introductory language on the new proposed Disclosure Forms to explicitly note: "You may want to compare offers from multiple installers or Approved Vendors. You should take whatever time you need to shop around and to fully understand the contract before signing." The extension of the rescission period from 7 to 14 days also provides additional opportunity for a customer who did not fully understand an offer, was subject to high-pressure tactics, or who simply changed their mind, to rescind the contract without any penalty. IPA Resp. at 122.

While the Agency appreciates the Joint NGOs' attempt to find a common solution, the Joint NGOs proposal presents several drawbacks. First, the IPA has little visibility into the time lag between when a typical ILSFA DG residential customer signs an installation contract and when the installation occurs. Second, the benchmark of "date of installation" itself is unclear, as not all installations can be understood as commencing at a given point. Third, adding the possibility that the customer may cancel the contract up until the date of physical installation will certainly make financing of these projects riskier and more difficult. In light of this, and in consideration of the questions surrounding implementation, the IPA opposes this recommendation. IPA Rep. at 65-66.

4. Commission Analysis and Conclusion

The Commission agrees with the IPA that extension of the cancellation period to 14 days provides a sufficient opportunity for a customer who did not fully understand an offer, was subject to high-pressure tactics, or who simply changed their mind, to rescind the contract without any penalty. For the Joint NGOs' proposal to extend this period to the beginning of installation, the Commission agrees that it is difficult to define when installation begins, and the IPA will not know when this occurs. The Commission does not find that any change to the LTRRPP necessary on this issue.

H. Section 8.15 Grassroots Education Funding

1. ComEd's Position

In the filed Plan, the IPA includes a new proposal related to the use of grassroots funding under ILSFA to expand the kinds of activities covered by this funding to include non-educational activities, such as costs for low-income energy efficiency providers to perform preliminary site suitability assessments, and other activities and services that can be performed by community organizations to drive and facilitate ILSFA participation. Plan at 281; ComEd Obj. at 17-18.

While ComEd appreciates the challenges experienced by the IPA related to grassroots educational efforts, the budget (up to 5% of the ILSFA budget) is a maximum, not a minimum. Given the limited overall ILSFA budget, ComEd is concerned that the expanded grassroots activities described by the Plan may not be the best use of these funds, especially to the extent that they duplicate or overlap with other State-mandated programs. For example, it is critical that any proposals regarding energy efficiency first

be discussed with those utilities offering energy efficiency programs to ensure alignment and avoid duplication. ComEd Obj. at 18.

In its Response Comments, the IPA confirmed that it “has no objection to working directly with administrators of energy efficiency programs as the ILSFA grassroots education strategies are developed to avoid duplication.” IPA Resp. at 98. Similarly, the Joint NGOs asserted that the optimal method of addressing potential duplication issues is to require coordination among the Program Administrator, other energy efficiency programs, and utilities. JNGOs Resp. at 17; ComEd Rep. at 19-20.

Accordingly, to the extent the Commission approves the Plan with the IPA’s proposed expanded use of grassroots funding, the Commission should include the required coordination agreed to by ComEd, the IPA, and the Joint NGOs. ComEd Rep. at 20.

2. Joint NGOs’ Position

The Joint NGOs are supportive of the IPA’s plan to expand grassroots activities beyond educational activities. Although ComEd expresses concern that the expanded grassroots activities described in the Plan may not be the best use of the grassroots funds, the Joint NGOs note that the Agency has discretion in how to use the funding. Moreover, merging outreach efforts is a way to reduce costs of customer acquisition while also increasing the likelihood of finding customers who would benefit from solar and if a customer installs energy efficiency measures with solar panels the benefits to customers will increase. JNGO Resp. at 17.

ComEd is also concerned that energy efficiency measures in this program may be duplicative with other energy efficiency programs. Even if concerns about duplication may be valid, the better way to address this issue is to require coordination between the Program Administrator, other energy efficiency programs, and utilities, which the Plan recognizes. Thus, the Joint NGOs support the IPA’s use of funding to help engage community action agencies and low-income energy efficiency service providers. JNGO Resp. at 17.

3. LVEJO’s Position

The IPA Act, as amended by P.A. 102-0662, provides that the IPA may allocate up “to 5% of the funds available under the [ILSFA] Program to community-based groups and other qualifying organizations to assist in community-driven education efforts related to the [ILSFA] Program.” 20 ILCS 3855/1-56(b)(3). Out of the \$1.53 million made available to grassroots education in the 2019-2020 and 2020-2021 program years, LVEJO notes that the IPA only awarded grassroots organizations \$449,464 and \$500,000 respectively. These amounts are well below the statutory maximum. In the recent 2020-2021 program year, a dozen organizations distributed across Illinois received program funds that allowed them to work on grassroots outreach programs. LVEJO Resp. at 18-19.

LVEJO believes that in times like these when our community is still dealing with the devastating effects of the COVID-19 pandemic, grassroots outreach is more important than ever. With competing priorities, organizations will need more resources to ensure

that all communities may benefit from the ILSFA program. LVEJO supports IPA's intention to increase grassroots efforts in the ILSFA program. LVEJO Resp. at 20.

4. IPA's Position

The IPA has previously limited the activities funded through the grassroots education funding to direct community outreach and education. New language enacted by P.A. 102-0662 expands the scope of this prerogative by adding "and other activities." 20 ILCS 3855/1-56(b)(3). In the 2022 Plan, the Agency leverages this new flexibility to better coordinate "with similar initiatives, including ... energy efficiency programs, job training programs, and community action agencies," as it is required to do under Section 1-56(b)(2). The Agency plans to work with community action agencies, Approved Vendors, and grassroots educators to develop resources for cross-promoting energy efficiency programs and ILSFA, to coordinate customer enrollment, and perhaps to perform site suitability assessments, all to drive greater participation in ILSFA programs. IPA Resp. at 96-97.

ComEd objects to this expansion of the types of activities funded with the community-driven education set-aside. The Agency does not agree with ComEd's assessment of the availability of funds for community-driven education. The 5% maximum for the last three program years has been over \$1.5 million each year for grassroots funding, yet the Agency has only granted contracts for about \$500,000 in each of those years. Thus, these efforts already have room for expansion and diversification. Furthermore, the ILSFA budget has grown significantly due to amendments made through P.A. 102-0662, with the annual utility funding increased to \$50 million. That additional budget will proportionally increase the budget for community-driven education efforts as well. IPA Resp. at 97.

Given the chronic under-utilization of the ILSFA budget for the DG sub-program, the Agency believes that increasing efforts to reduce barriers to entry for that program is exactly the correct use of these funds. However, the Agency also notes ComEd's concern that energy efficiency first be discussed with those utilities offering energy efficiency programs to ensure alignment and avoid duplication. The IPA has no objection to working directly with administrators of energy efficiency programs as the ILSFA grassroots education strategies are developed to avoid duplication. The ILSFA Program Administrator has attempted to coordinate with ComEd in the past regarding job training requirements in ILSFA with limited success, so the IPA looks forward to this new prioritization of coordination from ComEd. IPA Resp. at 97-98.

5. Commission Analysis and Conclusion

The Commission sees no merit in ComEd's Objection. It is clear that the IPA has not used the statutory maximum of 5% of the funds available under the ILSFA Program. The Commission agrees with LVEJO that further community education and outreach is necessary to spur further participation in this program. The Commission approves of the IPA's plan to work with community action agencies, Approved Vendors, and grassroots educators to develop resources for cross-promoting energy efficiency programs and ILSFA, to coordinate customer enrollment, and perhaps to perform site suitability assessments, all to drive greater participation in ILSFA programs. In addition, the

Commission finds that this effort must be coordinated with those utilities that offer energy efficiency programs.

I. Section 8.17 Illinois Solar for All Advisory Group

1. LVEJO's Position

LVEJO notes that the IPA proposes to convene an ILSFA Advisory Group to assist the IPA in achieving the ILSFA program's success and LVEJO agrees that this is a vital addition to the ILSFA. LVEJO objects, however, that the IPA has failed to commit to a regular schedule for convening the ILSFA Advisory Group as part of the 2022 Plan. LVEJO states that part of the advantage of holding a regularly convened meeting at predetermined intervals is to ensure participants understand expectations and set aside meeting times. LVEJO asserts that meeting convened twice monthly is the best option to ensure adequate participation and involvement by all stakeholders but looks forward to working with the Commission and the IPA to find an appropriate interval. LVEJO Obj. at 12-13.

The Joint NGOs' call for the Agency to clarify the relationship between the SAG and Stakeholder feedback sessions, and to commit to scheduling SAG meetings monthly. LVEJO believes that clarity about the different functions and roles of the SAG and Stakeholder feedback sessions are vital for the Agency and the communities attempting to engage with it. Additionally, LVEJO supports the idea that SAG meetings need to be frequent and on a regular schedule. LVEJO fears that having less frequent or irregular meetings will result in inadequate feedback from communities to the Agency. LVEJO Resp. at 4-5.

2. Joint NGOs' Position

In the Plan, the Joint NGOs note that the Agency provides numerous praiseworthy opportunities for stakeholder feedback, including an Advisory Group and the SAG. The current underutilization of the Low-Income DG subprogram is particularly dire and would benefit from engagement within the Advisory Group and feedback from broader stakeholder sessions. However, it is not currently clear how these two stakeholder opportunities relate to each other and whether they are distinct opportunities. Furthermore, a cadence of meetings that is only quarterly would not be sufficient to address the myriad challenges facing low-income residential solar deployment. JNGOs Obj. at 22-23.

The JNGOs therefore suggest that the Commission require clarification as to whether the Advisory Group is distinct from the public stakeholder feedback sessions and require that Advisory Group meetings take place on at least a monthly basis, perhaps with quarterly reports of issues discussed and any relevant changes proposed for or made to the programs. Separately, open and informal public stakeholder feedback sessions should be held on at least a quarterly basis, possibly timed to take place after the release of Advisory Group reports. Information and suggestions gathered during these sessions could be discussed further by the Advisory Group or immediately implemented by the Agency, as appropriate. JNGOs Obj. at 23.

The Joint NGOs appreciate the IPA's clarification while disagreeing with the IPA's claim that that the Plan proceeding is not the proper place to outline the dates and

frequency of these sessions. For both the success of the ILSFA program and to ensure more effective stakeholder engagement, setting session frequencies through the Plan is necessary. The Joint NGOs encourage the Commission to require the IPA to commit to holding at least monthly meetings. In addition, the Joint NGOs emphasize that neither Advisory Group meetings nor public stakeholder engagement opportunities should be one-way presentations by the IPA or simply a venue for stakeholders to speak without any responses. Advisory Group meetings and public stakeholder engagements opportunities should instead be an iterative dialogue between the IPA and other parties. JNGO Rep. at 16.

3. IPA's Position

The IPA explains that it plans to establish a formal ILSFA Advisory Group. This Group will feature balanced representation from different constituencies (Approved Vendors, utilities, community organizations, etc.) and will meet regularly. The intent was that the Agency would meet with the ILSFA Advisory Group in addition to also hosting more public feedback forums. IPA Resp. at 98.

The Agency appreciates the strong interest in the ILSFA Advisory Group, but it does not believe that the Plan is the proper vehicle for determining meeting schedules. Many factors may influence the preferred frequency of meetings, such as important pending program determinations, holidays, and time required to ensure progress in between meetings. The IPA will commit to holding ILSFA Advisory Groups regularly with a target of once a month, with the possibility of changing that frequency depending on the need or availability of parties. IPA Resp. at 99.

The Joint NGOs also raise the ambiguity created by the 2022 Plan's reference to both the ILSFA Advisory Group and a more general stakeholder engagement process. To clarify, the Agency is planning to host regular meetings of the ILSFA Advisory Group, with a target of monthly meetings, in addition to ongoing stakeholder engagement opportunities that will be open to the public. The Agency sees these two parallel efforts serving different but related functions. The ILSFA Advisory Group ensures consistent attendance by a representative group of stakeholders deeply involved in ILSFA and knowledgeable about the program, whereas the public stakeholder engagement opportunities allow for input from individuals on a one-time basis, allowing those with limited availability to still communicate their experience with ILSFA and thoughts on potential improvements. The Agency believes that the Plan proceeding is not the proper place to outline the dates and frequency of these sessions and recommends that the commission reject those arguments. The Agency commits to clarifying the difference between the stakeholder feedback sessions and ILSFA Advisory group upon publication of the final Plan as approved by the Commission. IPA Resp. at 99-100.

4. Commission Analysis and Conclusion

The Commission appreciates the clarification offered by the IPA regarding the ILSFA Advisory Group and the stakeholder engagement opportunities and these stakeholder processes are approved. Also, although the Commission agrees that the actual dates that the ILSFA Advisory Group will be held are not appropriately included in the LTRRPP, the Commission finds that the IPA should provide an actual schedule in advance for the monthly meetings. Similar to Commission Regular Open Meetings, a

schedule provides notice to participants and allows them to schedule accordingly. The schedule should be posted on the IPA website.

VIII. CHAPTER 9 CONSUMER PROTECTION

A. Section 9.2 Consumer Protection Provisions Arising from Public Act 102-0662

1. Arcadia's Position

Arcadia appreciates that the IPA has added language to the LTRRPP to facilitate a stakeholder feedback process. Nonetheless, Arcadia respectfully objects to the LTRRPP's current proposed approach. The IPA seeks Commission authority to change its requirements, guidance, and documents for implementing the Plan without further Commission approval. While Arcadia can understand and appreciate the desire for this type of future flexibility, it raises some potential concerns about due process and administrative procedure under Illinois law, including under P.A. 102-0662 specifically. Arcadia Obj. at 8.

The LTRRPP's proposal would allow the IPA to change its own requirements, guidance, and documents after the Commission has reviewed and approved the Plan. However, if the IPA (or the IPA's Program Administrator) at some later juncture deems it appropriate to change its program requirements -- which no doubt could have a bearing on the due process rights of Approved Vendors and Approved Designees -- Illinois law appears to require that the IPA must propose those changes as amendments to the Plan, subject to Commission approval. Such a process would also ensure that stakeholders have a proper legal forum in which to properly consider and voice any potential concerns with such changes with both the IPA and the Commission. Arcadia Obj. at 8.

In advocating against such an approach, the LTRRPP appears to rely on historic Commission decisions relating to other IPA plans. Respectfully, the IPA's position appears to be inconsistent with recent amendments to the IPA Act. The General Assembly's recent P.A. 102-0662 states that "requirements applicable to participating entities" be set forth in the Plan. And there is no doubt that the Plan is subject to Commission review and approval. Thus, P.A. 102-0662 appears to change the landscape, such that although a prior Commission decision in Docket No. 19-0995 permitted post-Commission approval program changes by the IPA, the now-applicable legal framework does not permit such changes. Arcadia Obj. at 9.

Although the LTRRPP's proposal falls short of what appears to be the legal requirement for a Commission proceeding in the event of a change to program requirements, Arcadia recognizes and appreciates that the IPA has indicated its willingness to submit certain "material or significant" modifications to program requirements to a stakeholder feedback process. As a practical matter, a stakeholder feedback process, if properly applied, could effectively and efficiently address appropriate program modifications. A key issue in evaluating this proposal is determining what constitutes a "material or significant" program requirement modification. Experience teaches that the "material or significant" standard may be applied differently by different stakeholders, and that certain items that do not appear "material or significant" to the IPA are "material or significant" to market participants. Arcadia Obj. at 10.

To address this concern, if the Commission adopts the LTRRPP's proposed approach of referring the program requirement changes to a stakeholder feedback process, the Commission should clarify that every change to a program process, requirement, or document should go through that stakeholder feedback process. Such an approach will foster collaboration and better understanding by both the IPA and interested stakeholders regarding the impact of a proposed change and will avoid adverse effects or unintended consequences that might flow from implementation of a seemingly insignificant program change that actually has material or significant impacts. To the extent that the IPA implements a stakeholder feedback process to review changes to program process, requirements, or documents, that stakeholder feedback process should be open and inclusive of all interested stakeholders. Arcadia Obj. at 11.

Arcadia also appreciates the inclusion of many of these program-related materials and documents in the Appendices of the LTRRPP filed with the Commission. However, Arcadia notes one important exception to this. The ABP Guidebook has not been included with the LTRRPP but is referenced several times in the LTRRPP. The ABP Guidebook should be included for Commission review, amendment (if needed), and approval. Arcadia Obj. at 13.

2. Joint NGOs' Position

The Joint NGOs state the IPA appropriately reserves the ability to modify consumer protection materials outside of the Commission approval process, which avoids an overly onerous process that would not benefit consumers or other program participants. To ensure appropriate stakeholder engagement, the IPA's process to evaluate proposed modifications should be broadly inclusive and allow all interested stakeholders a chance to provide feedback. JNGO Resp. at 18.

The IPA's approach balances the statutory requirement to propose program "terms, conditions, and requirements" through the Plan review and approval process at the Commission, with the flexibility necessary to manage the RPS programs in practice, including through the modification of programmatic materials on an as-needed basis. See 20 ILCS 3855/-175(c)(1)(M). As the IPA states, this approach is consistent with the Commission's past practice. The latest statutory language is similar to the existing language mandating that the IPA develop "terms, conditions and requirements" for other RPS program areas, and does not explicitly reference alternate processes for consumer protection materials or address any of the specific documents previously maintained outside of the formal Commission process. See Section 20 ILCS 3855/1-75(c)(1)(N). Thus, there is no indication that the legislature intended to require the Commission and the IPA to change their approach to the review, approval, and management of the RPS programs. JNGO Resp. at 19-20.

Moreover, from a practical perspective, requiring every modification to programmatic materials to proceed through the formal Commission review and approval process would be time-consuming and costly for all involved, without clear benefit to consumers, vendors, or other interested parties. The current approach allows the IPA to respond more readily to any changes in market conditions or consumer-related concerns that may arise as the programs proceed. Without such flexibility, the programs may run into issues related to their documents, which could result in participant confusion and

other programmatic risks while the IPA seeks and waits for Commission approval. Such delays and resulting disruptions may ultimately threaten the programs' longer-term viability and success. JNGO Resp. at 20.

3. The Joint Solar Parties' Position

The Joint Solar Parties appreciate and support a consolidated Consumer Protection Handbook. The Joint Solar Parties also appreciate its inclusion with the LTRRPP for informational purposes. However, given that it was first included in its current form with the filing of the LTRRPP and is over 100 pages (in addition to the over 300 page LTRRPP), the IPA should not seek nor receive explicit approval of the Consumer Protection Handbook in this docket. Instead, the Commission should at most approve the IPA publishing a Consumer Protection Handbook and allow the IPA to amend the Consumer Protection Handbook from time to time rather than force litigation of its aspects in a 120-day docket with other substantial issues at stake. JSPs Obj. at 41.

4. LVEJO's Position

While LVEJO agrees that the IPA must generally seek Commission approval before modifying program requirements, the Illinois Administrative Procedure Act ("APA") allows for the modification of certain rules on an emergency basis outside of a formal rulemaking procedure. Section 5-45 of the APA allow state agencies to adopt emergency rules. The APA defines an emergency as "the existence of any situation that any agency finds reasonably constitutes a threat to the public interest, safety, or welfare." When a state agency believes that an emergency exists that they must respond to before a formal rulemaking process can be conducted, the agency may adopt an emergency rule for up to 150 days. LVEJO Resp. at 15.

The IPA should be allowed to utilize these emergency rulemaking powers to respond quickly to any consumer protection issues that threaten the public interest, safety, or welfare. By their very nature, the consumer protection requirements of the ABP and the ILFSA programs are designed to protect consumers' interests, safety, and welfare. Issues that affect the consumer protection requirement of these programs fall into the definition of an emergency laid out in the IAPA. Therefore, LVEJO opines that the Agency has the power to temporarily modify these provisions in response to an emergency if such a response requires swift action. The LTRRPP should ensure that the Agency has the authority to respond to emergencies affecting consumer protection. LVEJO opposes Arcadia's Objection to the IPA's ability to modify consumer protection requirements of the ABP and the ILSFA programs. LVEJO Resp. at 16.

5. IPA's Position

JSP and Arcadia both object to the Agency's proposed approach for compliance with Section 1-75(c)(1)(M) of the IPA Act, which directs the Agency to "propose the [ABP] terms, conditions, and requirements," including specifically enumerated consumer protection requirements, "through the development, review, and approval of the Agency's long-term renewable resources procurement plan." To meet this new statutory requirement, the Agency both described existing and proposed consumer protection requirements and documents in the 2022 Plan and attached over 100 pages of relevant documents and materials in Appendix I. The Agency seeks approval of the document

and underlying requirements as proposed, while retaining the flexibility to modify materials as needed going forward. The Agency proposes that any material or significant modifications to these requirements or documents between approval of this and future Long-Term Plans would be implemented after a stakeholder feedback process (except in the case of emergency changes). IPA Resp. at 100.

The JSPs' and Arcadia's Objections to the Agency's proposal conflict, with Arcadia stating that the Commission must review and approve every program process, requirement, and document, and JSP arguing that the Commission should not even make a determination regarding approval of the proposed Consumer Protection Handbook. The Agency's position is a reasonable middle ground that fully complies with the IPA Act and also allows for the flexibility necessary for efficient and nimble implementation of the solar incentive programs. IPA Resp. at 100.

In response to Arcadia, the IPA states that it updates, and the Commission approves, the LTRRPP every two years, and that the solar market can evolve quickly. It is critically important that the Agency have the flexibility to adapt and respond to changes in the market, including new marketing techniques and offer structures, as well as broader contextual changes, such as the COVID-19 global pandemic. Arcadia's proposal would mean either (1) the Agency could not do anything between Plans to address new market dynamics or consumer protection concerns, or (2) the Agency would be forced to reopen and re-litigate program details for every modification, creating significant delay, a drain of administrative resources, and an unreasonable burden on the Agency, the Commission, and stakeholders. IPA Resp. at 101.

The IPA notes that the Commission explicitly approved this exact type of flexibility in its Order approving the Revised Long-Term Plan in Docket No. 19-0995. The Commission explained that the Agency is permitted to make general changes to its consumer protection requirements outside of a Plan proceeding with a 45-day lead time and may "maintain an emergency pathway for immediate implementation of new or modified consumer protection requirements when warranted." Furthermore, and contrary to Arcadia's argument, the Agency's proposal to continue the approach previously approved by the Commission is entirely consistent with Section 1-75(c)(1)(M) of the IPA Act. While the Agency is now required to include its consumer protection requirements in its Long-Term Plan, the law in no way prohibits updates to consumer protection requirements or materials between Plans as appropriate, assuming those updates are consistent with the Commission's broader direction. IPA Resp. at 102.

Arcadia raises a related objection regarding the ABP Guidebook. Arcadia argues that the Agency should have included the ABP Guidebook with the 2022 Plan for Commission review and approval. While the Agency acknowledges that the Program ABP Guidebook is an important program document - it effectively serves as a user manual for the program - the Agency disagrees that the ABP Guidebook itself must be approved by the Commission. The ABP Guidebook is a very detailed and lengthy document (over 100 pages) that implements the ABP as described in the Plan, which is approved by the Commission. Furthermore, the Program Administrator and Agency regularly update the ABP Guidebook and are currently in the process of updating the ABP Guidebook. It was therefore impractical, and potentially would have been confusing, to include the existing copy of the ABP Guidebook when a new version is currently being developed and may

even be published for stakeholder input before the 2022 Plan is approved. IPA Resp. at 102-103.

The IPA notes that it has proposed to implement a stakeholder feedback process for any material or significant modifications (other than emergency measures) to program requirements between Plans. Arcadia's proposal is that any change to the implementation of the program or wording on a document, no matter how minor, and regardless of whether it simply clarifies an existing requirement or updates materials (such as eliminating outdated references to waitlists), or is urgently needed to respond to an emergency, must go through a stakeholder process. This is impractical and would hamstring the Agency's ability to effectively administer the solar incentive programs. IPA Resp. at 103-104.

The IPA is the state agency tasked by statute with administering the solar incentive programs. It is an impartial actor and uniquely situated to identify consumer protection concerns, pinch points, and other program issues, and determine whether a stakeholder process is appropriate before implementing changes. IPA Resp. at 104-105.

JSPs object that the Agency should not seek Commission approval of the Consumer Protection Handbook in the Plan proceeding. The Agency understands Section 1-75(c)(1)(M) requires the Agency to propose its consumer protection materials for review and approval by the Commission. While the Agency recognizes the concern that its 2022 Plan and Appendices include a lot of material, the Agency disagrees with the assertion that the Commission should not approve the content of the Consumer Protection Handbook. First, the statement by JSP that the Consumer Protection Handbook is "over 100 pages" is incorrect. The entire Appendix I (including Minimum Contract Terms and Disclosure Forms) is over 100 pages, but the Consumer Protection Handbook on its own is 31 pages excluding the cover page and table of contents. Second, the majority of the requirements contained in the Consumer Protection Handbook already exist in the current ABP Marketing Guidelines and ILSFA Consumer Protection Guidelines. Third, the Agency produced and published an annotated version of the Consumer Protection Handbook that flags substantive changes between the current consumer protection documents and the proposed Consumer Protection Handbook, to assist stakeholders in their review of the Handbook. The Commission should both approve the proposed Consumer Protection Handbook as attached to the 2022 Long-Term Plan and should also allow the Agency to update the Consumer Protection Handbook between Plans as appropriate. IPA Resp. at 106-107.

LVEJO supports the Agency's authority to modify Program requirements between Plan updates and points to the APA's provision that allows agencies to create emergency rules without a formal rulemaking process. While the Agency appreciates this support, it disagrees with LVEJO's suggestion that the Agency's authority to do so comes from the Illinois APA. The Agency maintains that it does not have the authority to promulgate its Program requirements as formal rules under the APA. However, the Illinois APA's provisions allowing for emergency rules do reflect a relevant policy consideration that is, the need for state agencies to be able to react in emergency situations to protect the public interest. Similarly, the Plan proposes that emergencies are one context in which the Agency may modify Program requirements and/or materials without a stakeholder process. IPA Rep. at 73.

6. Commission Analysis and Conclusion

The Commission agrees with the process proposed by the IPA for approving both the Consumer Protection Handbook and the ABP Guidebook. The Commission does not see anything in P.A. 102-0662 that would prohibit this process. The Commission finds that approving the Consumer Protection Handbook in this proceeding satisfies the requirements of Section 1-75(c)(1)(M) of the IPA Act. 20 ILCS 3855/1-75(c)(1)(M). The Commission has previously approved the IPA's ability to make modifications and no reason has been given to support a change to that process. Arcadia's Objection is not adopted.

Also, the stakeholder process proposed by the IPA is approved. The Commission will not require that every modification, no matter how minor, must be vetted through the stakeholder process. No party points to any issues with this process that has been in place for years. And, although the Commission does not encourage this, as a last resort any disputes can be brought to the Commission for resolution.

B. Section 9.3.3 Disciplinary Determinations

1. Arcadia's Position

The IPA's portfolio of activities has expanded greatly since the IPA's inception, and includes a variety of responsibilities, programs, and regulatory activities that were not part of the Agency's original charge. As a result of that expansion of functions, Arcadia points out that the IPA now regulates business entities that engage in a wide variety of different activities within the overall context of the Illinois renewable energy landscape. Arcadia Obj. at 11.

The expansion of the IPA's functions presents some challenges as it relates to disciplinary determinations. For example, although the IPA now has decisional authority regarding disciplinary determinations that can affect the core business interests of some entities participating in IPA programs, the IPA does not appear to have a decision-making process or infrastructure that is documented, segmented, and staffed in a manner similar to other administrative agencies. While this may well be a resource issue that is beyond the IPA's own control, it can create the perception that the IPA may, in some circumstances, be rendering decisions affecting entities under IPA authority in a manner that is quite different than other agencies. Arcadia Obj. at 12.

Arcadia appreciates that Section 9.3.3 of the Plan provides some new direction regarding the process surrounding IPA disciplinary determinations for entities subject to IPA regulation. That said, it is an open question whether that information meets the applicable legal standard. For example, the IPA Act indicates that: "The provisions of the [APA] are expressly adopted and incorporated into this Act, and apply to all administrative rules and procedures of the Agency." 20 ILCS 3855/1-30.1. The APA requires that: "All agencies shall adopt rules establishing procedures for contested case hearings." 5 ILCS 100/1-30; Arcadia Obj. at 12.

It is certainly arguable that IPA disciplinary determinations affect the "individual legal rights, duties, or privileges" of entities regulated by the IPA. Accordingly, the lack of formalized administrative rules regarding disciplinary determinations, together with the

lack of segmented staffing within the agency for purposes of rendering disciplinary decisions, seems potentially problematic. Arcadia Obj. at 12.

In the context of this statutorily expedited Commission proceeding, it is unlikely that the Commission itself or the IPA would consider themselves to be in a position to fashion and establish a path to implementation of formal administrative rules plus a segmented and staffed administrative structure for disciplinary determinations by the IPA. That said, in order to encourage the IPA, the Commission, and stakeholders to consider this issue for future action, Arcadia respectfully objects to the current disciplinary determinations procedure outlined in Section 9.3.3 of the Plan. Arcadia Obj. at 13.

2. IPA's Position

The IPA avers that it does not possess or exercise plenary regulatory authority. The Agency administers state incentive programs, which do not constitute the Illinois solar market generally. The Agency's disciplinary determinations only concern ongoing eligibility for benefitting from state-administered incentives. A solar company may choose to avoid the Agency's consumer protection requirements simply by not participating in or marketing in connection with the programs. IPA Resp. at 107.

The Commission agreed with this understanding of the Agency's role in the proceedings on the Initial and Revised Long-Term Plans:

The Commission does not find designating an entity with the Approved Vendor status to be the legal equivalent of a license grant. There is no indication in the statute that the legislature intended for the IPA to grant a license in this circumstance. Also, it is clear to the Commission that the IPA does not have regulatory authority over this industry. The IPA is administering a program for which interested parties must comply with the rules if they wish to receive the benefits of the program.

Docket No. 19-0995, Order at 56. Section 9.3.3 describes the Agency's current disciplinary process, which includes reasonable procedural safeguards like a 45-day lead time for new requirements, an opportunity to respond to complaints or other alleged or apparent program violations, and the opportunity to appeal a suspension by the Program Administrator to the Agency. The Agency also states its intent to implement a stakeholder feedback process to develop additional guidelines to ensure that, as the programs continue to expand and address a growing number of complaints, disciplinary responses continue to be carried out in a fair and consistent manner. IPA Resp. at 107-108.

Arcadia points to the APA and questions whether the Agency is required to promulgate formal rules for contested cases that adjudicate legal rights, duties, or privileges of a party. The IPA argues that, unlike agencies with plenary regulatory authority, the Agency does not determine legal rights, duties, or privileges. As the Commission has confirmed, the Agency simply determines eligibility to participate in a state-administered incentive program. In Docket No. 17-0838, the Commission explained, "[t]here is no requirement in the IPA Act that any adoption of terms and conditions, which include consumer protection provisions, must be conducted pursuant

to the rulemaking provisions of the Illinois Administrative Procedure Act. Furthermore, it would be inconsistent with the IPA's adoption of guidelines in previous procurement dockets." IPA Resp. at 109.

Moreover, Section 1-35 of the IPA Act provides that "[t]he Agency shall not adopt any rules that infringe upon the authority granted to the Commission." 20 ILCS 3855/1-35. Because program requirements and processes are required to be proposed as part of the Plan, which must receive approval by the Commission, the IPA does not have legal authority to promulgate rules related to the programs. Finally, Arcadia does not argue an affirmative position, but simply raises questions, nor does it offer a specific recommendation, making its objection insufficiently concrete for implementation. IPA Resp. at 109.

3. Commission Analysis and Conclusion

The Commission notes that Arcadia does not propose any revisions to the LTRRPP, but merely states a concern that the IPA's processes do not conform with the APA. Arcadia does raise an interesting question about whether the IPA's continually expanding role requires more formal processes be adopted even if not explicitly required. Arcadia's objection, however, seems to be more a general observation and the Commission does not see that any specific action is required in this Order and it might be an issue best addressed with the legislature.

A review of the LTRRPP process outlined in Section 9.3.3, however, shows that, in the event of problematic behavior, notice will be provided which: 1) outlines the problematic behavior; 2) explains how the behavior is non-compliant with program requirements; and 3) requests more information about the issue. In order to put the recipient fully on notice, the Commission finds that this notice should also include any penalties that might result.

The Commission continues to find, as with previous plans, that it is appropriate and reasonable that the IPA only provide this incentive funding to Approved Vendors or Approved Vendor Designees that comply with the programs' rules. The processes outlined by the IPA are sufficiently clear for interested parties to understand what is necessary to receive the benefits of this program.

C. Section 9.4.1 Consumer Protection Handbook

1. Joint Solar Parties' Position

The Joint Solar Parties support a complete ban on the use of the utility logo in sales and marketing, except in very limited circumstances. The JSPs explain that using the utility name in a non-deceptive manner is not only useful, it is critical to communicate necessary information to a customer. Because by definition community solar subscribers, for instance, must be retail customers of the same utility to which the system is interconnected, offers are necessarily linked to one utility service territory or another. Similarly, due to differences in markets (including energy markets as it impacts net metering), offers for behind-the-meter or community solar may be only available in a certain utility service territory. JSPs Obj. at 40-41.

While the proposed Consumer Protection Handbook does allow generally for non-deceptive use of the utility name, it requires explicit program administrator approval for

use of a utility name in defining a product or service. This will require pre-review of all advertisements for utility-specific offers, which the Joint Solar Parties believe are many if not most offers. This approach is both impractical and an administrative burden on both the Program Administrators (who already receive all marketing materials on at least an annual basis) and the Approved Vendor. JSPs Obj. at 41.

The Joint Solar Parties notes that the IPA clarified - and proposed conforming modifications to the Consumer Protection Handbook - that non-deceptive use of the utility name to define availability/eligibility or the source of bill credits does not require preapproval. The Joint Solar Parties appreciate the IPA's clarification and recommend that the Commission approve the IPA's proposed changes. JSP Rep. at 40.

The Joint Solar Parties further assert that the Approved Vendor should not have to translate the contract or subscription except in Spanish, because the Disclosure Form is currently only available in English and Spanish. The Approved Vendor or its Designee should also have the option to terminate a sales presentation if the customer does not reasonably understand the language of the sales presentation and the Approved Vendor or Designee does not elect to use a translator. JSPs Obj. at 42.

2. LVEJO's Position

LVEJO notes that the IPA does not prohibit ballooning loan payments in the 2022 Plan. Instead, the IPA imposes three additional requirements before an Approved Vendor can directly pass through some or all of the REC incentive payments to the customer. LVEJO argues that the proposed prerequisite requirements serve only to protect certain consumers (i.e., they only protect consumers that will receive direct payments from their Approved Vendor and will not protect consumers whose systems are indirectly subsidized) from the danger of ballooning loan payments. LVEJO maintains that the IPA's proposed requirements are an inadequate substitute for a more protective, complete ban on ballooning loan payments. LVEJO Obj. at 16.

LVEJO believes that the customer should have the ultimate power to choose the language in which the customer wishes the contract and standard disclosures should be provided. Specifically, LVEJO asserts that any Approved Vendor that advertises or conducts sales activities to consumers that speak languages other than English should be required to provide program material and contracts in the language that the consumer understands. Failure to provide these materials in a language the consumer understands should be considered a deceptive marketing or bad faith business practice. LVEJO Resp. at 13.

However, LVEJO understands that this requirement may place an unreasonable burden on smaller AVs with limited linguist resources. Therefore, while LVEJO maintains its desire that all program material, standard disclosures, and contracts that are provided to consumers by AVs be provided in a language that the consumer understands, LVEJO is amenable to the AV's right to terminate a sales contract if the AV is unable to comply with this requirement. LVEJO Resp. at 14.

The consumer protection provisions of the ABP and the ILSFA programs already require Approved Vendors to "conduct business affairs with the goal of openness and transparency and shall not seek to take advantage of or otherwise exploit a customer's

lack of knowledge.” The consumer protection provisions further provide that if “an Approved Vendor or Designee becomes aware that a customer misunderstands a material issue in a solar transaction..., the Approved Vendor or Designee should correct that misunderstanding.” These consumer protection provisions already require an Approved Vendor to act fairly and ensure that a consumer understands the system they are purchasing. LVEJO believes that if an Approved Vendor is unable to ensure that a consumer understands the system they are purchasing - whether that be because the Approved Vendor is unable to communicate to a consumer in a language that the consumer understands or for any other reason - the Approved Vendor should be required to terminate all sales transactions. LVEJO Resp. at 14.

3. ComEd’s Position

Given its past and ongoing experiences with deceptive marketing practices, ComEd supports the IPA’s proposal in the Consumer Protection Handbook. Requiring the IPA to perform this important pre-approval function related to the use of the utility name by non-utilities in their materials will serve as an important safeguard to avoid deceptive or confusing marketing and advertising. ComEd Resp. at 17.

4. IPA’s Position

LVEJO objects to the IPA’s proposed response to a concerning trend around loan payments, arguing that the IPA should create an outright ban on all ballooning loan payments and that the IPA’s proposal only protects customers who receive direct REC payments from their Approved Vendors. The Agency understands that entering into a contract for a DG solar project is a significant financial commitment for Illinois residents and businesses and acknowledges that poorly designed financing methods can have significant impacts on customers. IPA Resp. at 110.

The IPA clarifies that the trends that it sees in the solar market are not the type of ballooning payment structures that are sometimes seen in other contexts, such as with mortgages, where a loan has low payments for several years and then an extremely high lump sum payment at the end of the term. Rather, the IPA identified a trend specifically with DG projects that are purchased where some or all of the REC payment is passed through from the Approved Vendor to the customer. Some of the installation or third-party financing contracts for this subset of projects include new or increased payment responsibilities for the customer tied to the expected date for the passthrough of the REC payment to the customer. If, due to various delays or other issues, the Approved Vendor does not pass through the REC payment at the expected time, the customer is still responsible for new or increased payments to their installer or third-party financier. IPA Resp. at 110-111.

Based on this trend, the IPA proposed a narrowly tailored solution to address this specific concern without being overly prescriptive with respect to financing structures. Specifically, the IPA proposed that, for purchased solar projects where the Approved Vendor passes through some or all of the REC payment to the customer, the Approved Vendor must (1) invoice for the incentive payment in a timely fashion, (2) pay the incentive to the customer after receipt in a timely fashion, and (3) not use the customer’s share of the incentive payment to meet other financial obligations of the Approved Vendor. IPA Resp. at 111.

It is possible that LVEJO is concerned about an additional consumer protection issue with loan structures. If that is the case, however, it is an issue that LJEVO has not explained, and the Agency is therefore unable to address. The IPA hopes that recalibrating the Consumer Protection Working Group with a broader focus and set of participants will allow for better information flow between all interested parties. IPA Resp. at 111.

The JSPs are concerned that the Consumer Protection Handbook requires Program Administrator approval for use of a utility name to explain in which geographic area an offer is available. That was not the intent of the Agency in including this language in the Consumer Protection Handbook. The Agency agrees that non-misleading factual statements about the utility service territory an offer is available in should not require pre-approval by the Program Administrator. The Agency also recognizes that entities may reference a utility name in describing how net metering or community bill crediting works—for example, “You will receive credits on your ComEd bill based on the amount of electricity that your share of the community solar project generates that month.” This type of reference to the utility is not misleading and has value in helping customers understand how they receive economic benefits from their DG project or community solar subscription. IPA Resp. at 112-113.

The Agency proposes to modify this section of the Consumer Protection Handbook to clarify that (1) Approved Vendors and Designees may use a utility name to describe the service territory in which an offer is valid, and in referencing or describing DG net metering or community solar subscription bill credits, provided the use of the utility name does not inaccurately imply utility affiliation or endorsement; and (2) pre-approval by the Program Administrator is only required for any other use of utility name, logo, etc. The Agency further proposes that the Consumer Protection Handbook note that if there is any doubt as to the propriety of the use of a utility name, it is recommended that the entity seek Program Administrator pre-approval. IPA Resp. at 113.

The JSPs also raised several consumer protection issues that it believes “are better addressed outside of a 120-day compressed docket” and suggests that the Commission direct the Agency to work with stakeholders on several specific issues. While the Agency does not generally object to working with stakeholders, it would like to respond substantively on the issues raised by the JSPs. The JSPs assert that Approved Vendors “should not have to translate the contract or subscription except into Spanish,” and that entities should be able to “terminate a sales interaction if the customer does not reasonably understand the language of the sales presentation and the Approved Vendor or Designee does not elect to use a translator.” IPA Resp. at 113.

The IPA explains that the Consumer Protection Handbook includes a section on marketing to consumers who do not speak fluent English. The Agency is aware that some ARES have targeted non-English speakers in marketing and have taken advantage of the customers’ inability to fully understand the offer. The Agency hopes to prevent such predatory marketing tactics in its solar incentive programs. IPA Resp. at 113-114.

That being said, the Agency does not see a conflict between the position of the JSPs and LVEJO and the proposed Consumer Protection Handbook. In Section IV, the Consumer Protection Handbook provides that, when a customer’s English language skills

are not sufficient for the customer to understand information presented in English, the Approved Vendor or Designee must find a sales representative who is fluent in that language, use an interpreter, or terminate contact with the customer. Similarly, if an Approved Vendor or Designee cannot comply with the requirement to provide written materials in the language requested by the customer, the Approved Vendor or Designee simply must terminate contact with the customer. There is no affirmative requirement for an Approved Vendor to translate materials or use a translator- they simply cannot market offers and make sales to customers who cannot reasonably understand the information provided. IPA Resp. at 114.

5. Commission Analysis and Conclusion

The Commission notes that with respect to the use of the utility logo, the Joint Solar Parties state that with IPA's clarification it recommends the Commission approve the IPA's proposed changes. The Commission agrees and the IPA's proposed changes are adopted.

The Commission also notes that the Disclosure Form is currently only available in English or Spanish. The Commission agrees that the Disclosure Form and any communications with the customer must be in a language that the consumer understands. The Commission finds that the IPA's proposal complies with this requirement.

For ballooning loan payments, the Commission finds that the IPA has explained its proposal to address consumer loan structures. The Commission finds this proposal satisfactory and notes that LVEJO did not file Reply Comments disagreeing with IPA's explanation. The Commission also notes with approval the IPA's suggestion that further concerns in this area can be addressed in the expanded Consumer Protection Working Group.

D. Section 9.4.2.3 ABP CS Minimum Contract Requirements

1. Joint Solar Parties' Position

The Joint Solar Parties recommend that the Commission direct the IPA to work with stakeholders on removing the insurance and operations and maintenance requirements from community solar subscription agreements and instead make holding full cost-of-replacement insurance or adequate self-insurance a program requirement. The JSPs further recommend that the IPA should clarify, if a subscriber attempts to assign their subscription to another customer, whether the assignee must sign a standard Disclosure Form. If so, the LTRRPP and Consumer Protection Handbook should explicitly allow the system owner to reject an assignment if the assignee attempts to take assignment before executing a standard Disclosure Form. In addition, a system owner should have the right to require a minimum credit score for assignees, especially given that "net crediting" under Section 16-107.5(1)(4) of the Act does not protect the system owner against customer non-payment. JSP Obj. at 42.

The IPA did not object to the Joint Solar Parties' request to address these items in stakeholder processes. The JSPs appreciate the IPA's willingness to engage in stakeholder processes on these issues and recommend that the Commission approve this approach. JSP Rep. at 41.

2. IPA's Position

The IPA can see potential benefits to embedding insurance requirements elsewhere in the Program requirements instead of the contract with the customer and does not object to exploring this further with stakeholders. The Agency also does not object to working with stakeholders to further clarify requirements around community solar subscription transfers. These sorts of suggestions emphasize the importance of the IPA retaining flexibility to update Program details and the benefit to interested parties of not being required to litigate every single Program requirement or document in the Plan process and instead being able to discuss issues in a cooperative and less formal process. IPA Resp. at 114-115.

3. Commission Analysis and Conclusion

The Commission finds that these topics are best explored through the stakeholder process. Both the Joint Solar Parties and the IPA seem to agree that this is the best route for addressing these proposals. It is adopted.

E. Section 9.5.1 ABP Disclosure Forms

1. Arcadia's Position

Arcadia argues that the Disclosure Form regimen is overly burdensome for all involved parties, resulting in the denial of the benefits of community solar to customers who would like to enroll. The current process involves creating a customer-specific form via a portal managed by the IPA, having the customer sign the form in an IPA-prescribed format, and submitting a signed form via the IPA-managed portal. Each of these steps is unique among community solar programs across the country, even in states with active third-party administrators. Arcadia Obj. at 13-14.

Arcadia opines that each step of the process creates a roadblock to robust community solar participation. For example, in Arcadia's experience, creating a customer-specific form in the IPA-managed portal is frequently met with delays, often so lengthy that the customer stops the enrollment process before the form is created. Similarly, requiring the customer to sign a new form when immaterial elements of their subscription change creates a significant barrier to participation. Arcadia Obj. at 14.

The net effect of these barriers is that Arcadia has approximately 2,000 customers in Illinois who have done everything necessary to demonstrate interest in community solar and who would be enrolled in community solar in any other state, but who are denied the opportunity to benefit from community solar due to an overly burdensome Disclosure Form process. Arcadia Obj. at 14.

In Arcadia's opinion, one of the most effective ways to reduce the operational and administrative challenges associated with the Disclosure Form is to remove the requirement that the form be executed by the customer. For example, the program could have a rule that the customer Disclosure Form be delivered to the customer, not executed via a specific software implementation and filed with the Program Administrator. The goal of this form is to disclose information about the program and potential savings - but it is not a contract. The IPA Act states that "[t]o discourage deceptive marketing or other bad faith business practices, the IPA may require direct program participants, including agents operating on their behalf, to provide standardized disclosures to a customer prior to that

customer's execution of a contract for the development of a DG system or a subscription to a community solar project." 20 ILCS 3855/1-75(c)(1)(M)(iii). As such, Arcadia maintains that the law requires disclosures but does not require customer document execution. Arcadia Obj. at 14-15.

Arcadia proposes an additional fundamental process modification to facilitate customer access to community solar: the Disclosure Form should not be customer-specific or utility account-specific, but rather should be designed as a tool to explain the terms of the contract. This would conform with the IPA Act which requires "standardized disclosures to a customer prior to that customer's execution of a contract." 20 ILCS 3855/1-75(c)(1)(M)(iii). Arcadia Obj. at 15.

In addition to reducing the administrative burden on parties seeking to sign up customers for community solar subscriptions, this change would improve the customer experience. A shortened, streamlined form would enhance customer understanding while reducing the amount of time customers must spend reviewing documentation. The standardized form would still explain to the prospective subscribers how savings for their subscription would work through an example based on 10,000 kWh/year (or \$100/month of credits). This puts the savings into terms that are straightforward and easily translated to that specific customer's usage. Arcadia Obj. at 15.

A standardized form would also remove the technical challenges associated with generating the form via the IPA portal. The IPA states that "[t]he [IPA] shall strive to minimize administrative expenses in the implementation of the Adjustable Block Program." (20 ILCS 3855/1-75(c)(1)(M).) Having a standardized, non-dynamic form would significantly reduce the administrative expenses associated with the program (without sacrificing the legislative intent of consumer protection). Arcadia Obj. at 15-16.

If the LTRRPP is not modified to require use of a standardized Disclosure Form, then, at a minimum, increased flexibility should be incorporated into the process to reduce the administrative and operational burdens that are directly impacting potential and current subscribers, and other market stakeholders. Arcadia Obj. at 16.

In addition, Arcadia appreciates the change the IPA has proposed to facilitate the right-sizing of community solar subscriptions. Increasing the allowable size band from the greater of 2kW or 10% to 5kW or 25% for community solar subscriptions will allow Approved Vendors and their Designees to make adjustments to a customer's subscription size based on increased usage. This will ensure the subscriber is receiving the maximum benefit from their community solar subscription. Arcadia Obj. at 16.

Also, Arcadia asserts that community solar in general, and customer experience and savings opportunities specifically, would be improved by giving Approved Vendors and their Designees flexibility to switch the project with which a subscriber is enrolled. This would ensure that projects remain fully subscribed and subscribers receive the maximum benefit from their subscriptions. Particularly among small subscribers who might have usage fluctuations, they may be better suited to be moved to a project that could accommodate an increase in their subscription size. Arcadia Obj. at 17.

Similar to the IPA's proposal in the LTRRPP to notify a customer when a subscription size change is made, Arcadia proposes a notification to customers to

communicate a change in the project to which a customer is assigned. In Arcadia's experience, subscribers have not shown preference or requests to be connected with specific projects; rather, subscribers prefer to be connected quickly with a project, and to receive the benefits associated with that subscription. Currently, in order to move a customer between projects, Approved Vendors must terminate the customer's current subscription and have the customer execute a new Disclosure Form, even in the event of an outage or other issue with their current project. Arcadia Obj. at 17-18.

2. Staff's Position

Arcadia takes issue with the Plan for requiring the Disclosure Form to be executed by customers. Staff does not support Arcadia's objection. Requiring a customer signature provides evidence that customers were provided the sales contract which helps ensure that customers understand the terms and conditions of their installation as discussed in the Plan. Staff Resp. at 15.

Staff notes that the IPA agreed to modify the Plan to allow community solar providers to switch customers between community solar projects with notification rather than execution of new Disclosure Form, but in only two circumstances. First, where the customer requests to be switched to a different project. Second, where the customer requests an increase in their subscription size that cannot be accommodated by the current project. Staff has no objection to the Plan being modified on this issue consistent with the IPA's Response Comments. Staff Rep. at 18-19.

3. LVEJO's Position

LVEJO opposes Arcadia's proposal to remove the requirement that the Disclosure Form be executed. LVEJO asserts that the standard Disclosure Forms serve an important purpose of providing an additional level of protection to consumers that are considering participating in the ABP. The execution requirement serves as proof that the customer received the standard disclosures and had the opportunity to study the system they are purchasing. LVEJO argues that a delivery-only requirement would not sufficiently serve this purpose. LVEJO Resp. at 16-17.

LVEJO opposes Arcadia's suggestion that the IPA implement a uniform document to replace the customer-specific standard Disclosure Forms. The standard Disclosure Forms are intended to protect consumers by "discourage[ing] deceptive marketing or other bad faith business practices." LVEJO asserts that a customer-specific standard Disclosure Form will be better suited to prevent unscrupulous business practices than the uniform standard Disclosure Form which Arcadia promotes. LVEJO Resp. at 18.

4. Joint Solar Parties' Position

The Joint Solar Parties object that customer e-mails should not be required on the standard Disclosure Form. As an initial matter, the JSPs explain that while the IPA generally requires standard Disclosure Forms to be generated via the Program Administrator's website, the Program Administrator has granted some Approved Vendors the ability to generate standard Disclosure Forms outside the website via an Application Programming Interface. If the standard Disclosure Form is generated by the Application Programming Interface, there should be an option to leave that field blank if the customer is going to execute the IPA's e-mail waiver form. The IPA recently identified using

fictitious or sales agent e-mails as a concern, but the Joint Solar Parties understand that current functionality (at least in the Application Programming Interface) does not allow for the option of customer refusal. The Joint Solar Parties further recommend reconsideration of the requirement that a customer provide their e-mail address in addition to their address (both service and billing), phone number, and utility account number. JSPs Obj. at 43.

5. ComEd's Position

ComEd notes that the IPA adopted ComEd's recommendation to include an additional customer disclosure addressing the impact of an owner or operator of DG electing a DG rebate under Section 16-107.6 of the PUA. Plan at 312. Because this disclosure equally applies to both the ABP and ILSFA, ComEd recommends that the disclosure first be discussed in Section 9.5.1 (ABP Disclosure Forms) rather than held for discussion in Section 9.5.2 (ILSFA Disclosure Forms). ComEd Obj. at 18. In ComEd's Reply, it confirmed the IPA's support for including a discussion of DG rebate impacts on retail customers' tariff options in both Sections (see IPA Resp. at 121), and ComEd therefore recommended that the Commission adopt this approach.

6. IPA's Position

One of the key elements of the Agency's consumer protection requirements is the standard Disclosure Form. Approved Vendors and Designees must complete a standard Disclosure Form for each customer, and the customer must review and sign the form before they sign the installation or subscription contract. These steps are fundamental to customers receiving clear and standardized information about the program, customer rights, and the specific offer, including costs, fees, and other terms. IPA Resp. at 115.

In their list of items that they believe should be addressed through a stakeholder process, JSP make two points about the customer email field in the Disclosure Form. First, JSP argue that if an Approved Vendor or Designee generates a Disclosure Form using an Application Programming Interface to communicate with the portal, "there should be an option to leave that field blank if the customer is going to execute the IPA's e-mail waiver form." The IPA explains, however, that the current portal does allow for the email field to be left blank, including when using the Application Programming Interface, if the customer does not have an email address that they wish to provide. First, the Approved Vendor or Designee would complete the Disclosure Form with the customer email field left blank. Then they must submit the email waiver document. Then the portal will allow for submission of the Disclosure Form without a customer email filled in. IPA Resp. at 116-117.

The JSPs further recommend reconsideration of the requirement that a customer provide their e-mail address in addition to their address (both service and billing), phone number, and utility account number on the Disclosure Form. The IPA states that the JSPs seem to suggest that a customer's email address is somehow redundant with their other contact and personal information. However, the IPA states that a large portion of Disclosure Forms submitted by Approved Vendors and Designees are signed electronically. In these cases, having the customer's email address helps the Program Administrator confirm whether the e-signature was executed through the customer's email address, as an indicator of the validity of that Disclosure Form execution.

Furthermore, it provides an additional method for the Program Administrator to contact a customer if questions arise around their enrollment or other Program-related issues. The Agency does not support eliminating the customer email address field from the Disclosure Form. IPA Resp. at 117.

Arcadia objects to many aspects of the Disclosure Form requirements and process, claiming that the Agency's requirements are "unique" among community solar programs and create "roadblock[s] to robust community solar participation." Arcadia points vaguely to challenges with creating customer-specific Disclosure Forms and claims the Agency requires customers to sign a new Disclosure Form "when immaterial elements of their subscription change." IPA Resp. at 118.

The IPA states that it is proud that Illinois has some of the most robust consumer protections in the country when it comes to state-administered solar incentive programs. Requiring customers to review and sign a customer-specific Disclosure Form prior to enrollment in community solar is critical to ensuring customers receive clear consistent information about their solar options. Requiring a signature from the customer—rather than simply requiring the company to provide the form to the customer—helps ensure that the customer actually views the document, and signals to the customer that the information contained in it is important. Furthermore, requiring companies to generate and submit customer-specific Disclosure Forms through the ABP portal allow the Program Administrator and Agency to monitor the market, the content of offers, and how companies are presenting information in the Disclosure Form. IPA Resp. at 118.

It is unclear what "lengthy delays" Arcadia is referring to in its Objections, but it is worth noting that the Agency has taken steps to reduce the overall burden from requiring customer-specific Disclosure Forms. For example, companies can use an Application Programming Interface or upload spreadsheets with comma separated values to create customized Disclosure Forms in bulk. IPA Resp. at 118.

Finally, Arcadia objects that the Agency should further improve the Disclosure Form itself. As explained in the plan, "[t]he Agency is open to further modifications to these Disclosure Forms through a stakeholder process, which it plans to commence after the approval of the 2022 Plan." The Agency notes that this is another example of why it is critical that the Agency retain the authority to adjust program documents outside of the Plan proceeding. IPA Resp. at 120-121.

The Agency also agrees with LVEJO that there is significant value in customer-specific Disclosure Forms that Arcadia's proposal of generic forms explaining contract terms would not provide. The purpose of the Disclosure Form is to provide key information to the customer about the Program, customer rights, and the specific offer being made to that specific customer, including subscription size, costs, fees, etc. This is incredibly important for DG systems, where each system is unique and offer details may vary significantly from customer to customer. Even for community solar, where offers may be more standardized, the customer's subscription size may vary drastically (for example, from a residential studio apartment to a large single-family house, or to a small commercial building). Regardless of how a community solar subscription is structured (e.g., a set price per kWh, a subscription fee set as a percentage of the bill credit), the subscription size will affect the overall costs and/or potential savings. For these reasons,

the Agency agrees with LVEJO that each customer should receive a Disclosure Form with information about their specific offer. IPA Rep. at 76-77.

Arcadia also objects that the Agency should allow community solar providers to switch subscribers between different projects without triggering the Disclosure Form requirements. In other words, Arcadia proposes the unrestricted shuttling of customers between projects. The Agency sees the value in some flexibility around project assignments. However, it is critical to retain limitations to prevent gaming, and the Agency remains mindful of the purpose of community solar and the importance of not eliminating a meaningful nexus between the customer and the project. As a policy matter, the IPA believes that the legislative intent behind the community solar programs was to incorporate an element of customer participation and objects to programmatic changes that would allow community solar to become too transactional in nature with too great a dissociation between the customer and the project. IPA Resp. at 120.

Therefore, the Agency proposes to modify Program requirements to allow community solar providers to switch customers between community solar projects with notification rather than execution of a new Disclosure Form in two circumstances: (1) where the customer requests to be switched to a different project, and (2) where the customer requests an increase in their subscription size that cannot be accommodated by their current project. IPA Resp. at 120.

In response to ComEd's proposal, the IPA states that it does not object to adding further explanation in Section 9.5.1 as well as in 9.5.2. Because specific sections of the Plan may be read in isolation, and because a commenter in the stakeholder process raised the need for a disclosure about the distributed generation rebate specifically in the context of ILSFA, the Agency supports including the discussion in both sections, but does not support moving it to Section 9.5.1 and eliminating the discussion in Section 9.5.2. IPA Resp. at 121.

7. Commission Analysis and Conclusion

With respect to the Joint Solar Parties' concerns regarding e-mails addresses, the IPA clarifies that an email address is not required when using the Application Programming Interface. Although it is possible for an Approved Vendor to submit a Disclosure Form with the customer email field left blank, the process does appear to require several steps. It seems clear from the IPA's statements that, in general, an email address should be required, unless there is some reason that a customer does not have one or does not wish to share one. The Commission agrees that in most instances an email address should be provided on the Disclosure Form and it is not redundant to the requirement that an address be provided.

The Commission notes that Arcadia objects to the requirement that the Disclosure Form be signed by customers. The Commission finds that this is an important consumer protection. The Commission agrees with LVEJO's position that the execution requirement serves as proof that the customer received the standard disclosures and had the opportunity to study the system they are purchasing. Requiring a signature from the customer, rather than simply requiring the company to provide the form to the customer, helps to ensure that the customer actually views the document, and signals to the customer that the information contained in it is important.

The Commission notes that the purpose of the Disclosure Form is to provide key information to the customer about the Program, customer rights, and the specific offer being made to that specific customer, including subscription size, costs, fees, etc. Because these programs are new to many people, the Commission finds that the IPA's proposal for a customer-specific Disclosure Form will help to lessen consumer confusion. Moreover, the Commission finds compelling the IPA's reasoning that requiring companies to generate and submit customer-specific Disclosure Forms through the ABP portal allows the Program Administrator and Agency to monitor the market, the content of offers, and how companies are presenting information in the Disclosure Form.

With respect to Arcadia's proposal that the LTRRPP should allow community solar providers to switch subscribers between different projects without triggering the Disclosure Form requirements, the Commission adopts the IPA's proposal. This proposal allows community solar providers to switch customers between community solar projects with notification rather than execution of a new Disclosure Form in two circumstances: (1) where the customer requests to be switched to a different project, and (2) where the customer requests an increase in their subscription size that cannot be accommodated by their current project. No further modification to the Plan is necessary.

Finally, the Commission approves the agreed proposal between ComEd and the IPA to include disclosure language related to the impact of a DG rebate election in both Sections 9.5.1 and 9.5.2.

F. Section 9.8 Consumer Protection Working Group

1. Joint Solar Parties' Position

The LTRRPP states that the IPA is meeting with consumer advocates on a regular basis to discuss the state of the market. The Joint Solar Parties state that the solar industry would greatly benefit from regular updates from the IPA or the Program Administrators on issues that they are seeing or concerned about in the market so that Approved Vendors and their Designees can proactively investigate their own practices. The IPA should commit itself or the Program Administrators to meeting at least semi-annually with industry stakeholders to present on positive and negative trends (in the opinion of the IPA and the Program Administrators) they are observing in the market. JSPs Obj. at 43.

The IPA indicated in its Response Comments that the Consumer Protection Working Group will be expanded to include the solar industry and address these topics. The Joint Solar Parties support the IPA's position. JSP Rep. at 43.

2. Arcadia's Position

Arcadia appreciates the IPA's incorporation of stakeholder feedback to expand the scope of the "Consumer Protection Working Group." Arcadia strongly believes that a forum for regular and direct communication between industry stakeholders, the IPA, and the Program Administrator will help the IPA respond to concerns and issues expeditiously. Likewise, Arcadia would benefit from hearing directly from the IPA and other stakeholders about problems and success stories in the market, enforcement decisions, and practical advice that allow industry participants to review their own operations and practices and better inform their decision-making. Arcadia Obj. at 18.

Arcadia recommends that the IPA post information on how to join the Consumer Protection Working Group on its program websites as soon as possible, as there are likely to be questions and valuable information to discuss during and following the final approval of the LTRRPP by the Commission. Arcadia Obj. at 18.

3. IPA's Position

In response to the Joint Solar Parties, the IPA states that in the 2022 Plan, the Agency proposes to reimagine the Consumer Protection Working Group (which currently meets monthly) as a broader discussion-based group, which would include industry participants, on things like trends, best practices, barriers to access, supporting Approved Vendors and Designees with training and other resources, and does not object to further exploring ways in which the Working Group can be optimized. IPA Resp. at 122-123.

Arcadia proposes that the Agency immediately post information on how to join the Consumer Protection Working Group so that the Working Group can discuss issues during and following the final approval of the LTRRPP by the Commission. The Agency does not believe it prudent to try to implement proposals, such as the reimagining of the Consumer Protection Working Group, before the 2022 Plan receives approval by the Commission. Furthermore, any discussions with interested parties during the Plan proceeding would potentially be *ex parte* discussions. If the Commission ultimately approves the Agency's proposed reimagining of the Consumer Protection Working Group, the Agency will promptly provide information on how additional stakeholders may join the group. IPA Resp. at 122.

4. Commission Analysis and Conclusion

It appears that the IPA has accepted the JSPs' proposal to discuss expansion and optimization of the Consumer Protection Working Group. Also, the IPA appears to agree with the substance of Arcadia's objection but does not think that implementation should occur until after this proceeding is complete. With these understandings, the Commission finds this issue to be uncontested and the IPA's position in Response Comments is adopted.

IX. CHAPTER 10 DIVERSITY, EQUITY, AND INCLUSION

A. Section 10.1 Equity Accountability System

1. Joint Solar Parties' Position

The Joint Solar Parties strongly support continuous improvement to the diversity of the solar energy workforce and understand that, for a variety of reasons, plans and measurements are a component of making that improvement. However, the number of reports proposed in the LTRRPP distracts efforts from compliance - especially for smaller and newer entities (including EECs themselves who are not exempt from reporting requirements) - and can be streamlined while remaining consistent with the statute. JSPs Obj. at 35.

The Joint Solar Parties thus propose the following approach to Equity Eligible Contractor goals and monitoring consistent with Section 1-75(c-10) of the IPA Act:

- Maintain the proposed education and initial submission of a compliance plan in late 2022 to early 2023.

- Around the end of 2023/beginning of 2024 and each year thereafter, in the applicable Approved Vendor portal provide a short-form update that allows an Approved Vendor to state whether it is on target to meet the goals in its plan and if not, which ones does it expect to fall short on and what corrective actions will it take. If the IPA determines that more action must be taken, it could require a Corrective Action Plan as contemplated in Section 1-75(c-10)(1)(B).
- Combine the backwards-looking annual report in 1-75(c-10)(1)(C) and any changes to the compliance plan required in Section 1-75(c-10)(1)(A) into a single report provided concurrently with the annual report.

JSPs Obj. at 36.

The JSPs are aware of the guidance on reporting released by the IPA on February 16, 2022, for Part II verification of projects. The Joint Solar Parties are highly concerned with the approach in that guidance to demographic and geographic reporting, especially for Small DG projects as it relates to “per project” issues. First, the requirement to report the number of hours worked by employees or contractors on construction and installation of each project should be broadened to include all types of employees to ensure full reporting of solar workers, including but not limited to, sales, transportation, permitting, and other administrative roles. JSPs Obj. at 36.

Even if sales and back-office employees, contractors, or vendors were included in the per-project count, the JSPs argue that Approved Vendor employees responsible for sales, permitting, or design would not be counted in some situations under the IPA’s guidance. For example, if a full-time sales employee pitches 10 projects to 10 different families, but only one moves forward (which is often the case), that employee would not be counted for the full time work they completed on the nine unbuilt projects but for which they are compensated. Similarly, sales employees or agents may spend significant time interacting with customers interested in Large DG (including schools) or subscriptions that end up not going forward for whatever reason (including using a competitor). Not counting these employees’, contractors’, and vendors’ time would not give the IPA a full picture in the required ethnicity and diversity reporting and the benefits of solar programs to solar workers. JSPs Obj. at 36-37.

Third, the JSPs opine that the reporting of hours and demographics on a per-project basis for Small DG is too cumbersome, given both the volume of projects in a day-to-day basis and how schedules and assignments can change daily depending on employee schedules, weather, or other considerations. This can also be problematic for small companies that do not have staff capacity to track this efficiently, adding to increased costs. JSPs Obj. at 37.

In the alternative, the Joint Solar Parties suggest quarterly employee demographic reporting (at least for employees whose work involves Illinois ABP and ILSFA systems) on an aggregated (rather than project-by-project) basis. The Joint Solar Parties are confident this alternative proposal would give more accurate information on the employment demographics in the industry while minimizing increased costs for administration. The Joint Solar Parties also support the IPA revisiting this process in future plans to ensure it is getting accurate data to meet state legislative requirements. JSPs Obj. at 37.

The Joint Solar Parties note that an Approved Vendor should have the option—but not be required—to submit any of the plans or reports identified above on behalf of a group of affiliated Approved Vendors. In addition, Approved Vendors that do not have any projects selected after the LTRRPP is approved should not be required to submit any of these reports unless or until they participate in a competitive or Adjustable Block Program procurement subsequent to the approval of this LTRRPP. This also avoids retroactive application of a requirement that does not commence until June 1, 2023. JSPs Obj. at 37.

The Joint Solar Parties appreciate and support the IPA's new, more expansive, definition of "project workforce" to cover a broader range of (Illinois-based) employees and contractors/subcontractors that combine to bring a solar project through its lifecycle. The Joint Solar Parties' Objection regarding the definition of project workforce would be satisfied by the IPA's proposal. JSP Rep. at 35.

However, the IPA did not support the Joint Solar Parties' proposal to conduct program data collection (inadvertently misidentified as related to Section 10.1 in the Joint Solar Parties' Objections) on an annual basis rather than a "per project" basis in the Part 2 application. *Compare* JSP Obj. at 37 with IPA Resp. at 133-134. The IPA justifies its approach by asserting (without an immediately apparent basis) that annual reporting is less accurate than per project data. At least for residential installers—who do not have to submit Certified Transcripts of Payroll like installers of virtually all non-residential systems—the Joint Solar Parties understand from their membership that more accurate data is available by looking at what the workforce does over the course of a year rather than individual projects. Annual reporting also provides a more accurate reflection of the workforce than per project reporting because small installation teams and the low number of hours on each residential project can skew system-specific demographics when only one or two individuals change on a work team, which can sometimes happen at the last minute. Looking at how different employees and contractors were deployed over the course of a year instead of project by project will more accurately reveal who makes up the solar industry workforce in Illinois. The Joint Solar Parties thus urge the Commission to adopt their original Objection and direct the IPA to collect project data on an annual and not per-project basis for residential systems. JSP Rep. at 35-36.

2. Joint NGOs' Position

The Joint NGOs support the JSPs' comments about the disproportionate administrative burden placed on small companies and the need to broaden the definition of workforce to include non-installation employees. The Joint NGOs also acknowledge that these comments are related to the specific implementation of the Plan and are likely too granular for the Commission's attention. JNGO Resp. at 21.

The Joint NGOs share the concern that reporting on a project-by-project basis will create unnecessary burdens for companies that focus on Small DG projects and support the alternative solution proposed by the JSPs. JNGO Resp. at 21.

The Joint NGOs urge the IPA to incorporate the JSPs' feedback about ensuring that all employees involved with project development are counted when determining compliance with the Minimum Equity Standards, not just construction and installation employees. The JSPs argue that the requirement to report the number of hours worked

by employees or contractors on construction and installation of each project should be broadened to include all types of employees to ensure full reporting of solar workers, including but not limited to, sales, transportation, permitting, and other administrative roles. The Joint NGOs believe this is fully aligned with the original intent of the Equity Accountability System designed in P.A. 102-0662 and urge the IPA to consider broadening the applicability as they improve their enforcement of the Minimum Equity Standards. JNGO Resp. at 22.

3. LVEJO's Position

LVEJO supports the JSPs' Objections regarding the demographic data collection process, particularly for contractors involved in Small DG projects. The JSPs' Objections focus on streamlining the process so that it better accounts for all workers at a company and is less of a burden for contractors that are engaged in several, smaller scale projects. LVEJO supports the overall goal of making demographic data collection more accurate to achieve a better understanding of demographics within the industry. Additionally, LVEJO supports the goal of helping to remove extra burdens from potential new, smaller equity or minority-owned contractors, and LVEJO believes that this proposal will help to advance that goal. LVEJO Resp. at 6-7.

4. CGA's Position

CGA states that the definition in the LTRRPP of project workforce to "located in Illinois" is ambiguous. This language should refer to the location in which the worker is performing work for the project that is the subject of the contract, and not the location of the worker's residence or worker's domicile or worker's place of employment. It is CGA's understanding that this is consistent with the application of Illinois labor laws. CGA Obj. at 8. CGA states that the IPA's response on this issue is sufficient to resolve it. CGA Rep. at 8.

5. IPA's Position

Section 1-75(c-10)(1) of the IPA Act establishes a new requirement for all applications for procurements of RECs under the IPA programs outlined in Section 1-75: that they comply with a minimum equity standard such that a certain percentage (starting at 10%) of "the project workforce for each entity participating in a procurement program ... be done by equity eligible persons or equity eligible contractors." 20 ILCS 3855/1-75(c-10)(1). IPA Resp. at 123-124.

CGA objects to the ambiguity of the phrase "located in Illinois" as used in the LTRRPP's definition. The IPA understands the fluidity of project labor crews and locations, but also wants to ensure that reporting entities do not include "office" workers that live and work outside of Illinois in their project workforce. Such an outcome would not serve the purpose the minimum equity standard, which is intended to increase access to clean energy jobs for Illinois workers. As such, the IPA agrees with CGA's suggestion that the best metric for defining "project workforce" in terms of location would be the location where the work is being performed, for both on-site workers and those doing support and business services. IPA Resp. at 124-125.

Given this recommendation, the Agency proposes to broaden the language regarding the direct relationship of the work with projects participating in IPA programs

and procurements. The IPA now believes that work performed in Illinois that is related to developing projects or educating consumers about program options should be included for the purpose of defining the “project workforce,” even if that work does not result in a project that receives a REC delivery contract. That foundational work is still employment that has been generated by the Illinois clean energy economy and should be included in meeting the minimum equity standard. IPA Resp. at 126. The IPA clarifies that the proposed definition of “project workforce” only includes those “back office” employees that work in Illinois. There are many national companies that participate in IPA programs and procurements and the Agency does not believe it would be consistent with the goals of the minimum equity standard to allow persons working in an office in California or Massachusetts to count toward complying with a standard designed to measure the equity of the Illinois clean energy sector. IPA Rep. at 79.

As laid out in Section 1-75(c-10)(1), the IPA Act requires compliance with the minimum equity standard through a specific reporting structure. That reporting structure, as articulated by the statute, includes: 1) a “compliance plan” submitted at “the start of each delivery year” by every entity “participating in a procurement program” of Section 1-75(c); 2) a confirmation of progress toward achieving the minimum equity standard in that year “halfway through each delivery year;” and 3) a report outlining how the entity achieved compliance with that year’s minimum equity standard from “each entity participating and completing work in that delivery year in a procurement program” of Section 1-75(c). The IPA explains that Chapter 10 of the 2022 Plan provides additional detail as to the requirements for the content of the compliance plan and annual report, method of evaluating compliance plans and reports, and processes for initial implementation of the reporting system. IPA Resp. at 126-127.

The Joint Solar Parties object to the number of reports required by the 2022 Plan and argue that the reporting can be streamlined while remaining consistent with the statute. First, the Agency notes that the Joint Solar Parties’ own recommendations are ambiguous and hard to follow. It is unclear whether the “short-form update” is meant to replace the compliance plan or the mid-year confirmation, yet the JSPs also propose that a single annual report replace the compliance plan and annual report on achievement. Joint Solar Parties do not explain how this single annual report would differ in content from the “short update.” Nor do they convincingly explain why these two submissions are less burdensome than the two submissions (the compliance plan and annual report on achievement) as proposed in Chapter 10 of the 2022 Long-Term Plan. IPA Resp. at 127.

Second, the statutory language is extremely specific and clear as to the reporting structure for the minimum equity standard. If the legislature wished to grant the IPA flexibility in designing the reporting structure and requirements, it could have done so. Instead, the statute lays out three separate elements of reporting: the annual compliance plan, a mid-year confirmation of progress, and an end-of-year report on achievement of the minimum equity standard. The statute does require that the Agency “pursue efficiencies achieved by combining with other Approved Vendor or designee reporting,” which the IPA has done. The Agency sought to reduce unnecessary reporting by making the mid-year confirmation a simple written communication and by allowing the year-end report to take the form of “an updated version of the original Compliance Plan submitted at the commencement of the delivery year.” The Agency also clarified that compliance

with the minimum equity standard is not required for entities that had no active projects or project applications in IPA programs that year. The Agency does not believe that the Joint Solar Parties' recommended changes would be consistent with the statutory language nor that they would significantly increase reporting efficiency. Therefore, the IPA cannot support the Joint Solar Parties' recommendations. IPA Resp. at 127-128.

Section 1-75(c-20) of the IPA Act directs the Agency to collect employee demographic and geographic data from each entity awarded contracts under any Agency-administered program. That data shall be used "to track and improve equitable distribution of benefits across Illinois communities for all procurements the Agency conducts" and the Agency shall "measure any potential impact of racial discrimination on the distribution of benefits" based on that data. 20 ILCS 3855/1-75(c-20)(1). In combination with the Equity Accountability System, the disparity study, and the Energy Workforce Equity Database, the collection of demographic and geographic data for the personnel of entities receiving REC contracts through IPA programs and procurements forms a key pillar of the Agency's authority to track progress in achieving the legislative objective of an equitable clean energy economy. IPA Resp. at 131-132.

The IPA issued guidance on February 16, 2022, on the collection of this data for the reopening of the ABP. That guidance adopted a two-part process for collecting data. First, updates to the Part II application for ABP projects will now request the aggregate hours worked by employees on that project by race, ethnicity, residential ZIP code, and status as a graduate of a qualifying job training program. Second, Approved Vendors will have the option of reporting the aggregate number of employees that qualify as equity eligible persons due to status as a formerly incarcerated person or a graduate of the foster care system in the existing Annual Report. The 2022 Plan does not include the details of the existing guidance but does commit to "provide stakeholders the opportunity to review proposals and provide feedback before any new information requirements are implemented." IPA Resp. at 132.

Joint Solar Parties also object to the burden that the per-project reporting process will create for small Approved Vendors, especially those that submit Small DG projects for which "the volume of projects in a day-to-day basis and how schedules and assignments can change daily depending on employee schedules, weather, or other considerations." It is in fact for that very reason that the Agency believed a per-project approach to be the best option—asking small Approved Vendors to track employee hours and compile them on an annual basis could result in inaccurate data. Instead, having the Approved Vendor report the employee data closer to the completion of construction makes it more likely that the data will be accurate. For this reason, the Agency does not support eliminating the per-project collection of demographic and geographic data in the Part II application. IPA Resp. at 133-134.

When evaluating reporting options, the Agency seeks to balance the often-opposing interests of creating an easy and efficient process for Approved Vendors and ensuring accurate data in order to achieve the broader purpose of monitoring and improving the distribution of benefits from the clean energy sector. While the Agency at the time believed this two-step approach struck the best balance of those competing priorities, it understands the points made by Joint Solar Parties in their objection. Therefore, the Agency proposes to evaluate the potential for overlap or duplication across

the processes for collecting demographic and geographic employee data during 2022, taking into account the many other new and existing reporting related to employee demographics. If the Agency later determines that changes to the existing procedure would streamline reporting while still ensuring accurate and comprehensive data, it plans to notify stakeholders of such proposed changes for feedback and seek to incorporate them into the next Plan. IPA Resp. at 134.

The Agency appreciates LVEJO's recognition, which aligns with the statutory language, that quality data is key to advancing the equitable distribution of the opportunities and benefits created by the clean energy economy in Illinois. See 20 ILCS 3855/1-75(c-10)(1). The Agency prioritized this very issue - data quality - when it chose to incorporate the collection of employee demographic and geographic data into the Part II application. If the Agency had elected to collect this data in the aggregate on a quarterly or annual basis, there could be a lag between construction and the recording of employee data, which could lead to inaccuracies. Instead, by requesting that project applicants submit this data with the Part II application, there would only be a gap of a few weeks, minimizing the risk of missing or inaccurate records. Regardless, the IPA also aims to reduce burdens for small and emerging businesses and proposed in its Response Comments to continue evaluating methods for reducing any overlap or duplication in reporting processes and to seek stakeholder feedback before adopting any such methods. IPA Rep. at 80.

The Joint NGOs also support the JSPs' Objections regarding the collection of employee demographic and geographic information as part of the Part II Application. They agree that this approach might create unnecessary burdens for Small DG installers and instead recommend that the Agency allow companies focusing on smaller projects to submit projects in aggregate or on a portfolio basis. In addition to the Agency's rationale for adopting a project-level reporting mechanism, the Agency also opposes this recommendation as overly vague. The Joint NGOs offer no criteria for determining which companies "focus on smaller projects"—and such a nebulous standard is unworkable. While the suggestion of submitting data on a portfolio basis offers reduced data accuracy concerns versus annual reporting, the Joint NGOs do not clearly explain why it is less burdensome for an Approved Vendor to collect the data and then aggregate it for reporting (as the Joint NGOs seek) rather than simply reporting the data on a continuous basis (as the IPA requires). Unless there is evidence demonstrating that requiring applicants to report on employee demographic data on a per-project basis is significantly more burdensome, the Agency does not support risking the accuracy of the reported data by moving to a less frequent reporting structure. If such evidence does emerge, the Agency will consider revising this guidance through a stakeholder feedback process. IPA Rep. at 80-81.

6. Commission Analysis and Conclusion

It appears that the IPA has satisfied the parties' concerns regarding the definition of Project Workforce. The Commission agrees with the IPA's position and it is adopted.

With respect to reporting, the Commission finds that the specifics of the reports that the IPA needs for both its own purposes and for complying with the law are indeed quite granular, as noted by the Joint NGOs. The Commission finds that the reporting of

demographic and geographic data for employees, which is required under Section 1-75(c-20) of the IPA Act, and the reporting of employee data for the purpose of complying with the minimum equity standard, which is required under Section 1-75(c-10), are satisfied by the IPA's proposal. The Commission agrees with the IPA that the Joint Solar Parties' proposed reporting approach is not an improvement to the IPA's proposal. Here again, the Commission notes with approval that, for these reporting requirements, the Plan commits to "provide stakeholders the opportunity to review proposals and provide feedback before any new information requirements are implemented." Plan at 327.

The Commission also notes the Objections to the IPA's proposal to collect data at the project level as opposed to on an annual basis. The IPA has appropriately weighed the burden on reporting entities with its need for accurate data.

B. Section 10.1.3.1 Waivers for the Minimum Equity Standard

1. CGA's Position

CGA explains that the entire Equity Accountability System is premised on the assumption that there will be a sufficiently trained volume of equity eligible contractors and persons for Competitive Supplies and Approved Vendors to comply with the Minimum Equity Standard as of June 1, 2023. There is, however, great uncertainty around the timing of when there will be eligible equity contractors and persons available, and if there will be a sufficient number of them to meet minimum equity standards. These uncertainties are not within the control of the competitive suppliers or Approved Vendors, but CGA points out that the Suppliers and Approved Vendors bear the administrative burden of the Equity Accountability System and are subject to substantial penalties for non-compliance until the necessary programs are in place and equity eligible persons are trained. CGA Obj. at 9-10.

CGA notes that an Approved Vendor or competitive supplier can seek a waiver from the minimum equity standard in the event it has made significant efforts to hire equity eligible contractors or equity eligible persons but cannot find such persons. According to the LTRRPP, such waivers are evaluated by the IPA on a case-by-case basis. Failure to comply with the minimum equity standard can result in a suspension from participating in future competitive procurements or the withholding of Approved Vendor status until a corrective action is filed with the IPA. 20 ILCS 3855/1-75(c-30). The LTRRPP lists ten different activities competitive suppliers and Approved ABP Vendors need to engage in to demonstrate significant due diligence in meeting the minimum equity standard. The evaluation of whether the effort was significant is left to the IPA to decide. CGA Obj. at 11.

To minimize the aforementioned risk and uncertainty competitive suppliers and Vendors are assuming, CGA proposes that the IPA use a point system to uniformly and efficiently determine whether significant due diligence has been performed. This will streamline the waiver process and make the risk around the waiver process manageable for competitive suppliers and Vendors because it will be applied through a uniform point system. CGA proposes that an applicant for a waiver would need to earn a minimum of 25 points to be granted a waiver. Points can be earned based by completing a combination of efforts. CGA Obj. at 11-12.

In its Response Comments, the IPA agreed with CGA that a scoring system with a minimum score to demonstrate qualifying for a waiver be used. The IPA proposes to develop such a system closer to the beginning of the 2023-2024 Delivery Year with stakeholder feedback. CGA anticipates that outstanding issues regarding criteria for the checklist will be addressed and resolved during the development of the waiver checklist. For purposes of this docket, CGA states that this issue can be considered resolved. CGA Rep. at 7.

2. IPA's Position

Sections 1-75(c-10)(1)(D) and (c-10)(4)(E) of the IPA Act allow the Agency to grant waivers of the minimum equity standard requirement in "rare circumstances," where "the applicant provides evidence of significant due diligence toward meeting the minimum equity standards." The Agency acknowledges the reality that it will take time to develop a pipeline of equity eligible persons in all geographic areas of Illinois through the job training programs to be established by the Department of Commerce and Economic Opportunity. The IPA anticipates that it will receive a large number of requests for waivers due to the lack of eligible equity persons that meet job criteria in the first years of implementation of the minimum equity standard. The Agency has set out a variety of actions an entity may take to demonstrate due diligence before making that request, including some actions laid out in the statute. IPA Resp. at 128-129.

CGA recommends that the two lists of examples of activities that qualify as "due diligence" be combined and requests that the Commission require the IPA to use a quantitative scoring system for evaluating whether an entity has met the due diligence burden. The IPA agrees that the Agency should apply these criteria in a uniform and transparent way and supports adopting a quantitative scoring system for the actions that the IPA will consider evidence of due diligence and a minimum score for qualifying for a waiver. The IPA proposes to develop that system closer to the beginning of the 2023-2024 delivery year (the first year in which the minimum equity standard will apply) and include information about that system in the webinars and trainings offered as part of the implementation timeline included in Section 10.1.2 of the 2022 Plan. IPA Resp. at 129.

3. Commission Analysis and Conclusion

It appears to the Commission that CGA has accepted the IPA's proposal presented in Response Comments. The Commission approves the CGA's proposal that waivers of the minimum equity standards should be granted based on a scoring system. In addition, the IPA's proposal to further develop that system with stakeholder feedback closer to the beginning of the 2023-2024 delivery year (the first year in which the minimum equity standard will apply) and include information about that system in the webinars and trainings offered as part of the implementation timeline included in Section 10.1.2 of the 2022 LTRRPP is approved.

C. Section 10.4 Energy Workforce Equity Database

1. CGA's Position

CGA argues that the Energy Workforce Equity Database that the IPA is to manage should include information regarding Qualified Persons. The requirement that solar installations be built by Qualified Persons needs to be taken into account alongside the

requirement to have equity eligible persons and EECs comprise a certain amount of a project workforce. See 20 ILCS 3855/1-56(h-5) and (i); 220 ILCS 5/16-128A. The labor pool for Qualified Persons is already limited. CGA recommends that the Energy Workforce Equity Database identify equity eligible contractors who are also Qualified Persons. Further, given that the IPA Act does not require Qualified Persons to install solar panels if the installer is part of the ILSFA Program (20 ILCS 3855/1-56(b)(2)(E), it would also be important to include ILSFA Program installers as qualified contractors to the Energy Workforce Equity Database. CGA Obj. at 9. CGA states that the IPA's Response Comments were sufficient to resolve these matters. CGA Rep. at 9.

2. LVEJO's Position

LVEJO supports CGA's proposal for the Energy Workforce Equity Database to also identify Qualified Persons for solar installation. LVEJO asserts that finding ways to make the Database a useful resource for entities in the industry is necessary to make it a useful part of the Agency's larger equity commitments. CGA's proposal will help advance the Database's greater goal of facilitating equity-based engagement by providing another relevant piece of information for developers. LVEJO supports the inclusion of this additional information, and it encourages the Agency to continue investigating other useful information that it could add to the Energy Workforce Equity Database. LVEJO Resp. at 8.

3. IPA's Position

The IPA notes that CGA objects to the Agency's described plans for developing the Energy Workforce Equity Database, requesting that the Agency include a designation for equity eligible persons that are also a Qualified Person. Section 1-75(c)(7) of the IPA Act requires that every DG facility is installed by a "qualified person," or someone directly supervised by a "qualified person," which is defined under the Commission's regulations of qualified installers. There is no public database of qualified persons, so the IPA would not be able to verify whether a person or contractor included in the Energy Workforce Equity Database was also a Qualified Person. However, the Agency is open to including a field for self-identification as a Qualified Person by equity eligible persons and equity eligible contractors seeking to be listed in the Energy Workforce Equity Database. The IPA proposes to include that design element in the database. IPA Resp. at 135.

4. Commission Analysis and Conclusion

The Commission agrees with the explanation provided by the IPA in its Response Comments. It appears that this matter is settled. The Commission approves the IPA's approach of allowing applicants to self-identify as a Qualified Person.

X. FINDINGS AND ORDERING PARAGRAPHS

The Commission, having considered the entire record herein and being fully advised in the premises, is of the opinion and finds that:

- (1) Commonwealth Edison Company, Ameren Illinois Company d/b/a Ameren Illinois, and MidAmerican Energy Company are corporations engaged in the retail sale and delivery of electricity to the public in Illinois, and each is a "public utility" as defined in Section 3-105 of the Public Utilities Act and an "electric utility" as defined in Section 16-102 of the Public Utilities Act;

- (2) the Commission has jurisdiction over the parties hereto and the subject matter hereof;
- (3) the recitals of fact and conclusions of law in the prefatory portion of this Order are supported by the record and are hereby adopted as findings of fact and conclusions of law;
- (4) the 2022 Revised Long-term Renewable Resources Procurement Plan, as modified herein, will reasonably and prudently accomplish the requirements of Section 1-56 and subsection (c) of Section 1-75 of the Illinois Power Agency Act;
- (5) the 2022 Revised Long-term Renewable Resources Procurement Plan, as modified herein, should be approved by the Commission; and
- (6) the Illinois Power Agency should file a compliance filing within 60 days of this Order consistent with the findings herein.

IT IS THEREFORE ORDERED by the Illinois Commerce Commission that subject to the modifications adopted in the prefatory portion of this Order, the 2022 Revised Long-term Renewable Resources Procurement Plan, is hereby approved.

IT IS FURTHER ORDERED that the Illinois Power Agency is directed to file with the Illinois Commerce Commission a compliance filing within 60 days of this Order consistent with the findings herein.

IT IS FURTHER ORDERED that all motions, petitions, objections, and other matters in this proceeding which remain unresolved are disposed of consistent with the conclusions herein.

IT IS FURTHER ORDERED that pursuant to Section 10-113(a) of the Public Utilities Act and 83 Ill. Adm. Code 200.880, any application for rehearing shall be filed within 30 days after service of the Order on the party.

IT IS FURTHER ORDERED that subject to the provisions of Section 10-113 of the Public Utilities Act and 83 Ill. Adm. Code 200.880, this Order is final; it is not subject to the Administrative Review Law.

By Order of the Commission this 14th day of July, 2022.

(SIGNED) CARRIE ZALEWSKI

Chairman