



June 27, 2017

Via Electronic Mail

TO:

Anthony Star
Director, Illinois Power Agency
Michael A. Bilandic Building, Suite C-504
160 North LaSalle Street
Chicago, Illinois 60601

FROM:

Richard Umoff
Regulatory Counsel and Director, State Affairs
Solar Energy Industries Association
600 14th St. NW Suite 400
Washington, D.C. 20005

**RE: Request for Comments on Long-Term Renewable Resources Procurement Plan
("LTRRPP")**

Please see the comments and recommendations of the Solar Energy Industries Association (SEIA) in response to request for comment regarding the Illinois Power Agency's Long Term Renewable Resource Plan (LTRRP). If you have any questions, you can reach me at the contact information below.

Sincerely,

/s/ Richard Umoff

Richard Umoff

Regulatory Counsel and Director
Solar Energy Industries Association

Phone: 202-556-2877

Email: rumoff@seia.org

SEIA appreciates the opportunity to provide the following comments and recommendations as the IPA develops its Long Term Renewable Resource Plan (LTRRP).

Established in 1974, SEIA is the national trade association of the United States solar energy industry and is a broad-based voice of the solar industry in Illinois.¹ Through advocacy and education, SEIA and its 1,000 member companies are building a strong solar industry to power America. There are 36 SEIA member companies in operation in Illinois working in all market segments – residential, commercial, and utility-scale – representing millions of dollars of in state investment and a significant portion of Illinois’ 4000 solar jobs.² SEIA member companies provide solar panels and equipment, financing, and other services to a large portion of Illinois solar projects.

Our comments are focused on developing a program that efficiently allocates resources, grows a diverse and competitive solar business ecosystem in Illinois, ramps up the State’s installation of solar, reduces costs over time, and drives customer and ratepayer benefit. We draw on the experience of our member companies to translate lessons learned from other markets and programs into our recommendations to the IPA.

Throughout our comments, we urge the IPA to use this LTRRP to establish a program framework that works for the long term, focusing on creating a transparent pathway to 2020 legislative requirements for new solar DG build and allowing for some flexibility to tweak aspects along the way.

A. GEOGRAPHIC ELIGIBILITY OF RENEWABLE ENERGY RESOURCES

IPA Question 1. What level of documentation and analysis should be required from an adjacent state project as part of a request that the Agency consider determining that the project is eligible to provide RECs for the Illinois RPS?

IPA Question 2. What would be an appropriate methodology for the Agency to use to determine that a project located in a state adjacent to Illinois meets the public interest criteria enumerated in Section 1-75(c)(1)(I)? For example, should it be a weighted scoring

¹ The comments herein represent the views of SEIA and not any individual member company.

² <http://www.seia.org/state-solar-policy/illinois>

system based upon each of the criteria outlined in the law contributing towards meeting a minimum aggregate score, or does a threshold level of compliance with each criterion have to be fully demonstrated?

SEIA supports IPA's goal that the Future Energy Jobs Bill delivers the many benefits of solar and other renewables to Illinois, including clean air, fuel diversity, and increased reliability pursuant to the Illinois Power Agency Act. To this end, SEIA encourages IPA to pursue a policy that drives new project development, as this is the most effective way of ensuring that the many benefits of solar energy are delivered to the residents of Illinois. Project eligibility requirements must also be consistent with federal law and should not be overly burdensome for developers. SEIA will provide further recommendations on this issue in later stages of the rulemaking process

B. MEETING PERCENTAGE-BASED RPS TARGETS

IPA Question 1. To incent the development of new resources outside the Initial Forward Procurement requirements and the Adjustable Block Program, how should the Agency consider balancing short-term REC procurements for meeting annual RPS percentage goals with procurements of multi-year commitments for RECs? In responding to this question, please consider that the eligibility requirements under the revised RPS may reduce the availability of eligible RECs from existing projects, potentially necessitating the development of new generation.

SEIA understands that revisions to the Illinois RPS will require the Agency to procure significantly more RECs than in previous years, and that balancing the new build requirements and meeting the overall REC procurement targets of the RPS will be challenging. However, the Agency has clear statutory direction to prioritize achieving the new build requirement over meeting the overall RPS targets: "... In the event of a conflict between these goals and the new wind and new photovoltaic procurement requirements...the long-term plan shall prioritize compliance with the new wind and new photovoltaic procurement requirements...over the annual percentage targets described in this subparagraph (B)."³

Furthermore, by the time the long-term plan is approved and the Adjustable Block Program is up and running, the IPA will have only 2 years to meet the goal of 2,000,000 RECs from each new

³ (20 ILCS 3855/1-75 (c)(1)(B))

wind and new solar. To reach this goal in this compressed time frame, the IPA will have to prioritize monies in the annual budget for these projects.

Finally, the utilities are required to spend up to half of unallocated funds for Delivery Years 2017-2019 on the Illinois Solar for All program if that program is not sufficiently funded through the appropriations process by August 2018. This could reduce the annual budget amount available to spend on the new build requirement in these years.

Given the uncertainty of these various factors and the timing of the approval and implementation of the long-term plan we believe that the IPA should not count on having significant funds left over beyond those needed to meet the new build requirements. And therefore, the IPA should not plan to procure any additional RECs in the initial long-term plan. If we find that the IPA is meeting the new build requirement with significant budget money left over, then the IPA can make revisions to the long-term plan during the biennial review.

However, if the IPA feels it has sufficient budget space to warrant procurement of RECs beyond the amounts required from new projects, then the IPA should use that additional budget to procure RECs from additional new projects that can help meet future new build goals. We do not believe that the IPA should spend budget monies on existing renewable energy projects, even if they meet the public interest criteria in the statute. Nonetheless, if the IPA does purchase RECs from existing projects, they should do so in single year contracts, not multi-year contracts, to minimize the budget impact from these short-term procurements.

IPA Question 2. Should the IPA develop distinct procurements that target specific renewable generating technologies beyond wind and solar? And if so, what technologies?

We believe priority should be given to meeting the new build requirements for wind and solar. Furthermore, the overall RPS goals require 75% of the annual REC target come from wind and solar. The new build requirements do not add up to 75% of the annual target, so if the IPA procures any additional RECs, they should focus on wind and solar. As mentioned above, we believe that any RECs procured beyond the new build requirements should also be from new projects.

IPA should focus its budget on meeting the new build requirements for solar and wind and should not, at this time, develop any distinct procurement targets for other technologies. The IPA can revisit this issue in the biennial review of the long-term plan and, if the market is meeting new build requirements with significant additional budget, adjust as necessary.

C. ADJUSTABLE BLOCK PROGRAM

The Future Energy Jobs Act provides broad direction on how the Adjustable Block Program would be applied to different solar market segments. It also sets the aggressive - but achievable - target of procuring 1 million RECs from DG solar by the end of Delivery Year 2020 (May 31, 2021). This translates into about 800MW of solar DG reserving capacity within the ABP program by this date. With the program likely to open about a year from now, the IPA needs to procure RECs through the ABP at an average rate of approximately 270MW/yr. This is up from a current installation base of 34 MW of non-utility scale solar⁴. With the reservation period that SEIA suggests in our comments below, the actual installation of these projects could take an additional 12 to 18 months beyond when a project reserves capacity.

The ramp up to creating an industry that can meet these targets is an eminently achievable goal - but the program must be structured in a transparent and efficient manner. SEIA urges the IPA focus in the near term on getting the market moving and to resist the temptation to overly prescribe or carve up the program. IPA should create a framework that is easy to understand and navigate and built for the long term and allows for sufficient flexibility to make course corrections along the way.

SEIA offers the following guiding principles when establishing the Adjustable Block Program:

- The program should establish a predictable and transparent framework where incentive levels step down in a known manner when pre-determined capacity amounts are achieved.

⁴ Solar Market Insight Report Q2 2017 – GTM Research, SEIA

- The program should be “always on” with incentives available to projects on their development timeline. Market forces should dictate the rate at which Illinois moves through the blocks.
- In order for the program to function efficiently and effectively, requirements for reserving program capacity should be set at a level that ensures program dollars are consistently committed to well-developed projects with a high probability of timely completion. Staff and the Program Administrator should pay close attention to project attrition and establish a transparent process for removing projects from the ABP that do not meet completion deadlines.
- Up-to-date information on the remaining available capacity in each block and DG segment should be readily available via the internet.
- Projects over 10 kW should have a performance-based incentive structure as part of the statutorily mandated payment schedule. This allows the IPA to explicitly prefer higher quality installations, as well as minimize the complications and risks of clawback provisions.
- Pricing and other terms in the program should be designed for stability to allow for long project development timelines.
- Simplicity should be a fundamental tenet of program design.
- Typically, we would expect block prices to adjust downward with falling costs over time. However, the Suniva case at the International Trade Commission (Investigation No. TA-201-75) presents a significant risk that prices may rise in the early years of the program. This should be taken into consideration.

Blocks

IPA Question 1. What approaches should the IPA consider for determining the size of blocks? What are the advantages/disadvantages of having a larger block size as opposed to a smaller block size?

When setting the blocks, IPA should consider the forward visibility into available capacity needed to enable a smoothly functioning market. If the capacity blocks are so small such that the market could move through multiple blocks in the time it takes to develop a project, then a

project in an earlier stage of development may not have sufficient visibility into what REC level it can expect, increasing the risk to expending development capital.

Price declines between blocks should be set small enough to discourage a ‘rush to the door’ effect from developers toward the end of a block. Also, they should be designed such that a project that just misses the capacity window for reserving capacity in one block can have a realistic expectation of sufficient project economics in the next block. Price declines should consider declining costs of solar year-over-year, as well as other factors such as the change in value of the DG rebate, the investment tax credit step-down, and other cost factors.

SEIA recommends the following Block structure, whereby the total capacity in each block is divided by each utility’s share of load and by the three DG categories (Small DG, Large DG, Community Solar). The below chart shows block allocation through the end of DY 2020. IPA discretionary capacity is not included. The capacity is for greater than 800MW because some segments may move through capacity faster than others, and the DY2020 requirement does not specify a certain number of RECs come from each segment at that point in time.

| | % of load (2015) | | Block 1 - 300MW | Block 2 - 200MW | Block 3 - 200MW | Block 4 - 200MW | |
|------------|------------------|-----------------|--------------------------------|-----------------|-----------------|-----------------|--|
| ComEd | 69.5% | Small DG | 69.5 (MW) | 46.33 | 46.33 | 46.33 | |
| | | Large DG | 69.5 | 46.33 | 46.33 | 46.33 | |
| | | Community Solar | 69.5 | 46.33 | 46.33 | 46.33 | |
| Ameren | 28.9% | Small DG | 28.9 | 19.267 | 19.267 | 19.267 | |
| | | Large DG | 28.9 | 19.267 | 19.267 | 19.267 | |
| | | Community Solar | 28.9 | 19.267 | 19.267 | 19.267 | |
| MidAmerica | 1.6% | Small DG | 4.8 (see below recommendation) | | | | |

| | | | | |
|--|--|-----------------|-----|--|
| | | Large DG | 4.8 | |
| | | Community Solar | 4.8 | |

Blocks should move independently on one another in an always on, first come first served manner. For example, when the Block 1 capacity for ComEd’s Large DG segment is full, the Block 2 capacity should open. If ComEd’s Block 1 Small DG segment is not yet full, it should stay open as Block 1 until that capacity is fully reserved and then move to Block 2.

Some categories may move more quickly than others. Therefore, to set a runway for meeting the 2020 requirement of 1M RECs under contract, the IPA should establish the framework for slightly more than this amount in this LTRRP.

Given the small capacity allocated to MidAmerican’s territory under the % of load allocation methodology, it is not realistic to use the exact same block structure as for the other utilities (this would result in blocks sizes of 1.2MW each.) Therefore, SEIA recommends opening all of MidAmerican’s capacity in each of the three DG categories (4.8MW in each) for Block 1 pricing. MidAmerican’s pricing for a given DG segment should move to Block 2 pricing when both of the other two utilities have moved to Block to for that DG segment. This will allow the opportunity for projects to be developed in the utility territory while also taking advantage of cost declines as the industry scales.

IPA Question 2. Should the category for systems between 10 kW and 2 MW be subdivided into distinct blocks? And if so, what are the appropriate break-points (e.g., 100 kW, 200 kW, 500 kW) between categories, and why?

In setting its program structure, the IPA should neither disadvantage projects based on size (i.e. by offering a one-size fits all REC price) nor should it force the market to be distributed in a certain way (i.e. by subdividing the Large DG category into distinct capacity blocks). In other words, IPA should encourage project diversity by accounting for the cost differentials between projects of different sizes rather than subdividing the Large DG category into distinct capacity blocks.

The system size of any particular project is dictated by several factors, including customer load and available space for system installation. Carving up capacity could encourage inefficient behaviors in the market. For example, if the capacity were subdivided and capacity was available in an earlier block for a smaller system size, a developer may size a system lower than they otherwise would in order to take advantage of the higher REC price in the earlier block.

IPA should set the base REC price for the Large DG category assuming a 2MW roof-mounted system. It should then estimate the price differential needed for different sized systems (taking into account cost differences as well as revenue differences from the NEM credit value and any applicable rebate) and establish an ‘adder’ to adjust compensation based on system size.

In Massachusetts, the Department of Energy Resources (DOER) has used this approach in designing their SMART program, where they have indexed the incentive level for different project sizes off of a 1 to 2MW system. Below are the size categories that Massachusetts has proposed:

- Less than or equal to 25kW
- Greater than 25kW to 250kW
- Greater than 250kW to 500kW
- Greater than 500 kW to 1MW
- Greater than 1MW to 2MW

New York does the following:

- 0-25kW
- 25kW - 200kW, 200kW - 2MW⁵

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

Given the expected 14-18 month lag between the passage of the Future Energy Jobs Act and the opening of this program, the market is likely to have built up significant initial momentum. Recognizing this, the first block should be larger to accommodate the expected pent-up demand at the beginning of the program.

⁵ New York is in the process of changing the 200kW threshold to 500kW.

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

Projects should be able to reserve capacity on a first-come first-served basis. In this initial Plan, the IPA should prioritize driving market activity and meeting its 2020 goals. If there are distinct policy goals that the IPA finds are not being met, then it can revisit this in the next plan. In general, any policy goals should be met through the use of adders to encourage market activity in a certain direction rather than requirements. See also SEIA recommendations in response to question #1.

IPA Question 5. How should the Agency handle the transition between blocks? Should a block close automatically upon being filled? Or should a block remain open until a predetermined date? Upon a block being closed, should the next block open immediately, or should there be some delay?

Blocks should be open until a predetermined megawatt allocation is reached. Once the capacity allocation for a given DG category in a block is reached, it should be closed and the subsequent block and associated REC price automatically opening. The program should be “always on” with incentive available to projects on their development timeline. Market forces should dictate the rate at which Illinois moves through the blocks. See also SEIA recommendations in response to question #1.

For this program structure to yield an efficient market where developers understand their ability to reserve capacity in a block, transparency into how much capacity remains in a block is critical. As such, SEIA recommends that the Program Administrator (or utilities) maintain a dashboard on the internet which is updated daily with information on remaining capacity. Regularly scheduled updates to available capacity are also critical. In the NY MW block program, for instance, it was not known when or how often the blocks were updated- once reservations were assigned or after applications were reviewed.

Additionally, the program manager must scrub the reserved capacity on a regular (weekly or monthly) and move quickly to add any forfeited capacity back to the currently open block. See SEIA recommendations in the Project Development Process section.

The Future Energy Jobs Act provides broad direction on how the Adjustable Block Program is to procure RECs from different solar market segments. It directly allocates 25 percent of REC procurement to each of three DG categories, and leaves 25% undefined. This unallocated REC requirement provides flexibility for the IPA to adjust capacity as needed. With the division between utility territories and the three DG categories, the capacity within each block quickly becomes divided. One of the principles of a declining block program is keeping each block sufficiently large to allow movement through the blocks at a reasonable pace that allows the market to react.

At this point, SEIA does not make a recommendation on specifically how to allocate this capacity. Instead, we recommend that IPA write the LTRRP in a way that gives it flexibility to use the capacity to monitor the program, consult with industry and other stakeholders, as needed without additional approval from the ICC. We recommend that IPA think about this unallocated capacity as a way to give additional capacity to market segments that are moving quickly as well as potentially providing capacity for underserved segments.

Prices

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

At the May 17 afternoon workshop, the IPA outlined two potential approaches for setting ABP REC prices: a cost-based model, and a market observation approach. However, given the fundamental underlying differences between Illinois and other markets - land costs, labor costs, property tax regimes, and energy values, to name a few – the IPA should not consider price points from different markets when determining block prices for Illinois under the ABP. The differences are too great, and the potential for error is far too high. Therefore, while it is important incorporate best practices from other states from a market structure perspective, the IPA should not consider incentive levels from other states when designating a block price.

Illinois has unique economic characteristics, as do other states. As such, each state's incentives are established independently of each other, and Illinois should follow suit and consider its own unique financial considerations. Given the variance in incentive levels in each state, IPA choosing pricing data from a specific state market can be subjective, problematic, and obstruct the effectiveness of the program. For example, 5-year SREC contracts in D.C. are currently offered at \$375/REC. In New Jersey, 5-year SREC contracts are offered at \$165/REC. In the Massachusetts SREC II program, 5-year SREC contracts are offered at \$200/REC.

During the workshop, the IPA cited incentive levels from the New York Megawatt Block Program and the Massachusetts SMART Program as a potential data points for the ABP. This is problematic, as the New York Megawatt Block Program has yielded underwhelming results. The Megawatt Block C&I dashboard shows 1.2 GW of reservations, but only 357MW of non-residential solar has been built in New York.⁶ While DOER has proposed the ceiling prices for the Massachusetts SMART Program, they are still subject to a public comment period, and even then, actual incentive levels have not and will not be determined until an auction event in Fall 2017. Moreover, it will be challenging to use data pricing from SMART, as the program is unlikely to officially open until summer 2018 and will then have to prove its effectiveness as measured by megawatts deployed.

When looking at pricing data from Illinois, the small sample size of the DG REC procurements over the last two years, as well as the variance in incentive levels between the different procurement events, may lead to inaccuracies. For example, the clearing price for last spring's 5-year DG REC procurement was \$141/REC, and the clearing price in spring 2017 was \$68/REC. Since only 27,702 RECs will be procured this year and 21,822 RECs last, these are not likely a representative sample, and winning developers put forth bids for only their most lucrative projects with customers that had a disproportionately high electric bill.

Instead of modeling incentive levels based on market observations from other states, the IPA should establish an initial incentive level based on an accurate evaluation of project economics in

⁶ Solar Market Insight 2017

each utility territory. Incentive levels should be based on consultant evaluations of project cost or models, with the opportunity for industry input.

IPA Question 6a. For the cost-based approach please provide recommendations for data inputs that should be considered for the model. If there are publicly available models that could be used as a template, please provide information about those models.

The IPA should include the following factors in establishing its incentive level and step downs:

- Module, inverter, and balance of system costs;
- Labor costs (including the cost of using organized labor and expected increases in labor costs);
- Interconnection costs (including expected increases in such costs);
- The impact of the federal ITC step-down, including components of project cost that are ineligible;
- The impact of rising interest rates on financing costs;
- Lease rates, avoidable electricity prices, and real estate costs across the state (including expected inflation in such costs);
- Marketing and ongoing customer management costs--particularly for community solar projects;
- The potential impact of revisions to the DG Rebate;
- Taxes

Moreover, the IPA should consider the impact of the DG rebate adjustment when 5% penetration is reached, and also provide itself with the flexibility to adjust incentive levels as the value of exported generation may be altered. The IPA should also consider scenarios in which the pending Suniva trade case may impact the incentive levels necessary to support Illinois solar projects.

IPA Question 6b. For the market observations approach, please identify the jurisdictions that could be considered, and any significant differentiators between those jurisdictions and Illinois that should be used to adjust results.

As discussed above, given the unique nature of the Illinois market, SEIA discourages the IPA from using other state's incentive levels as data points. Incentive levels should be designed to meet the unique characteristics of the Illinois market, including land and labor costs, property tax regimes, and the energy values which solar can offset, among other factors.

IPA Question 6c. Does the methodology for determining REC pricing have to be either cost-based or market observation based, or can it be a combination of both? Are there any

other approaches that should be considered?

The IPA should hire a consultant to conduct an accurate evaluation of project economics in each utility territory. Incentive levels should be based on consultant evaluations of project cost or models, with the opportunity for industry input. One method would be to issue a survey that allows developers to provide economic inputs and share assumptions. After each question, the questionnaire should have space in which a developer may explain their answers and provide further context to the IPA if they so choose. Given the complexity of such a survey, the IPA may consider publishing the survey draft in advance and allowing a brief comment period in which they collect industry feedback on its structure and requested inputs.

Any results of the analysis, as well as assumptions, should be published and transparent. Any consultant analysis should allow ample opportunity for stakeholder feedback. New York, for example, did not incorporate industry feedback in their final incentive levels for Megawatt Block. As a result, the C&I program has yielded underwhelming results.

IPA Question 7. How should the approach for determining REC prices take into account geographic differences in price or cost factors, e.g. local labor/land costs etc.? How narrowly or broadly should geographic factors be considered?

The IPA should consider project economics based on utility service territory and market segment. For example:

- Large distributed generation projects should assume either a) a 2MW rooftop project or b) a 2MW ground mount project and allow for an “addor” for rooftop projects.
- Community solar projects should assume a ground mount with 3 commercial offtakers as base price. The IPA may include an adder for residential subscribers.
- Small distributed generation project should assume a residential rooftop project.

Given that the adjustable block provides the IPA with the flexibility to later adjust incentive levels in case of rapid oversaturation or slow build rates, we recommend that the IPA begin with this simple approach and may later refine its methodology if necessary. For the initial release of the ABP, the IPA should err on the side of determining an incentive level to jumpstart the market; precision should not further delay the ABP’s implementation.

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

IPA should consider the avoidable energy value available to different commercial and industrial customer classes when creating differentiated pricing for RECs. For these customers, the majority of the distribution, transmission, and capacity charges are demand based. While solar is often coincident with peak demand for distribution, transmission and capacity, a combination of factors – peak demand being measured on only a few hours in the year, these hours fluctuating from year to year, and the fact that solar is intermittent – means that a customer cannot count on reducing their kW based rates. Since solar PV cannot predictably offset kW-based charges and therefore should not factor into financial calculations presented to customers, the IPA should not include these charges when calculating REC prices needed for demand based customers. Below are the avoidable energy rates for secondary customers⁷. Customers on primary service have a slightly lower avoidable cost.

| Demand Size | ComEd (\$/kWh) | Ameren (\$/kWh) |
|-----------------------------|-----------------------|------------------------|
| Less than or equal to 25kW | 0.05891 | 0.09118 |
| Greater than 25kW to 250kW | 0.04935 | 0.04288 |
| Greater than 250kW to 500kW | 0.04935 | 0.04288 |
| Greater than 500 kW to 1MW | 0.04935 | 0.04288 |
| Greater than 1MW to 2MW | 0.04820 | 0.04183 |

There are a host of other cost factors specific to different types of projects that IPA could consider, including carports and other land use cases. However, given the flexibility granted to the IPA to adjust incentive levels if necessary, and that the Future Energy Jobs Act does not have any additional public policy goals within the ABP aside from geographic diversity and build requirements for each market sector, SEIA believes the IPA should first focus on simplicity and may further refine any analysis on a later date if blocks are being filled too quickly, or if blocks are filled at a pace unsatisfactory to meet the statutory requirements. Moreover, the proceeding

⁷ Rates based on \$32 hourly PJM rate consistent with an industrial customer's RTC rate over the last 12 months, with the exception of the less than 25kW category which is the utility's non-hourly standard offer rate. Above avoidable rates include distribution taxes, but not excise or muni taxes. Per the tariff, distribution charges are all demand (kW) based for all rate classes above 1kW in ComEd and above 150kW in Ameren. All rates based on summer load pricing. All rates based on current utility tariff rates as of June 2017.

that will begin at 3% will allow for different valuations to be considered when 5% penetration is hit and will most likely lead to differentiated pricing.

Project Development Process

In order for this incentive program to function efficiently and effectively, the program rules must ensure that incentive dollars are consistently committed only to well-developed projects that have a high probability of timely completion, rather than to speculative projects that are not ready for procurement and construction, and that may not be built at all. With limited capacity and budget, the overall success of the program depends on its ability to allocate resources efficiently, fairly, and transparently, and to use those resources quickly once they are committed to a project.

IPA faces a balancing act when setting the bar for how advanced a project should be to reserve scarce program capacity. On the one hand, a program that is efficient and that minimizes risk around the incentive would remove uncertainty around the incentive available to a project early in that project's development cycle, so that developers are not forced to spend development capital when the project is still at risk of not receiving an incentive, or of receiving an incentive at a lower amount than anticipated. According to that logic, developers should be able to reserve program capacity for some period of time while they work to further develop a project.

However, the probability that a project is actually feasible increases as it is developed, so when program capacity is scarce, or, more specifically, when one project's reservation impacts all other projects, as it does under the declining block model, there is a compelling reason to force developers to prove-out their projects before reserving program capacity. There are two benefits to that: one, it ensures that a higher percentage of program awards go to projects that actually get built; and two, it becomes possible to shorten the reservation period during which a project can hold an award, because it is closer to construction when the award is made. According to *that* logic, developers should only be able to reserve program capacity once their project is reasonably well-developed.

Good program design does truly balance these considerations, in two ways. One, it sets project milestones that must be met for access to the program that are significant enough to be credible signals of project viability, but that are not so burdensome as to be intolerable in the absence of guaranteed access to a known level of incentive funding. Two, it is as transparent and predictable as possible about what incentive funding will be available to projects once they are ready to gain access to the program, so that market participants have the information they need to make their own risk-reward decisions about spending early-stage development capital. It's important to note that these two principles work well together.

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

IPA should allow projects 12 months from the date of capacity reservation with some limited ability for extensions. (See recommendation to question #10.)⁸

Twelve months allows for a project to work through any adverse seasonal weather that may limit construction. The project should not experience delays in permitting and interconnection because they have already obtained its non-ministerial permits and signed its ISA. PV equipment availability should not be an issue (absent the impacts of any remediation measures that may come from the Section 201 trade case in front of the ITC). This is based on a successful program in Massachusetts that also uses a 12-month window.

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

The ability for limited extensions is important. It is equally critical that the reservation period must be firm and objective and strictly enforced. The Program Administrator should monitor

⁸ Some of our companies recommend 18 months, with the option of requesting a 6-month extension. We suggest allowing further comment on this issue in the next phase.

the pipeline, regularly scrub any projects that miss their deadlines, and place that forfeited capacity in the then open block.

IPA should allow for the following extensions:

- Indefinite extension after mechanical completion
- 6-month extension for pending legal challenges
- One-time 6-month extension for fee (forfeited if project is not completed during this time frame)
- Extensions for good cause, as decided on a case-by-case basis by IPA

If a project does not meet its required deadlines, it will forfeit its reserved capacity and that capacity will be added to the block that is currently open.

For example, MW Block 1 Community Solar project in Ameren's territory falls out 12 months after it reserves capacity, and Ameren's Community Solar program is in Block 2 at that point, then the equivalent 2MW of capacity is added to Ameren's Block 2 Community Solar capacity.

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

Project development has four main components: site control, interconnection, permitting, and customer off-take. To minimize attrition and move to completion, projects need to have a strong grasp on the major cost categories (interconnection, any issues with permitting), have binding site control, and have a customer (or customers) associated with the project.

In community solar projects, the mix of customer offtake can vary greatly. Even though customer acquisition is critical to the ultimate completion of the project, SEIA recognizes that different business models will approach this in different ways and therefore hesitates to require a specific customer off-take agreement when reserving capacity in the Community Solar category. Similarly, SEIA would not support any *requirement* (beyond what is in statute) for a certain mix of customers in each project.

SEIA recommends the following milestones for reserving REC capacity in the ABP:

To reserve capacity in the Large DG segment, a project must have all of the below:

- Binding site control (a REC reservation cannot switch site locations)⁹
- Binding customer offtake agreement (may be contingent on REC reservation) (a REC reservation cannot switch customer offtake)
- Signed Interconnection Services Agreement (ISA); and
- All permits except ministerial permits (building, electric)¹⁰

To reserve capacity in the Small DG Segment:

- Executed turnkey contract between installer and customer

To reserve capacity in the Community Solar segment, a project must have all of the following:

- Binding site control (a REC reservation cannot switch site locations)
- Signed ISA; and
- All permits except ministerial permits (building, electrical)

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

By establishing milestones that require a project to prove out its viability, have spent money to get to the point where they can reserve capacity, so no additional deposit, a developer will have already spent significant capital to bring a project to this level of maturity.

In coordination with the project milestones SEIA has recommended for reserving capacity, SEIA does not see the need for additional deposit requirements, with the exception of an additional deposit in the case of a 6-month extension.

SEIA agrees with a nominal fee to defray the administrative costs of running the program.

⁹ May be contingent on REC reservation, as the Offtake Agreement and Site Control doc will go hand-in-hand for projects on customer-owned property.

¹⁰ SEIA would also like to flag the question of whether an interconnection study from the utility is required, as this can typically incur cost to the developer. If developers do not have confirmation of secured incentives, requiring interconnection fees places an undue burden on the developer, risking a large upfront payment for interconnection study without the assurance of securing optimal incentives.

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

With setting the milestones to reserve capacity at a stage in the project development cycle that ensures a high percentage of the allocated capacity is built, intermediate project milestones become less important. If IPA feels the need to establish interim milestones during the 12-month reservation period, there could be a couple light touch points. However, IPA should weigh the value of this with any administrative burden it brings.

IPA Question 14. For the Supplemental Photovoltaic Procurement, inverter readings were allowed for systems below 10 kW, and revenue grade meters were required for larger systems.⁵ How should these standards be updated for the ABP?

A twenty-five kilowatt threshold is appropriate in Illinois. In Maryland and D.C., all solar energy systems 10kW or larger require a revenue grade solar meter, while Delaware sets its threshold at 15kW.

Massachusetts and New Jersey now require revenue grade meters for all systems regardless of size. However, given the additional costs that this could add to a nascent solar market like Illinois for purchasing the equipment and installation, the Joint Parties would not recommend following that approach. These requirements may be revisited as market penetration grows.

Clawback Provisions

IPA Question 15. What clawback provisions would be appropriate for ensuring that RECs are delivered while not creating potentially prohibitive additional costs or burdens?

IPA Question 16. What would be reasonable circumstances to allow for the waiving of clawback provisions? (e.g., fires, severe weather, etc.)

IPA Question 17. Should clawback provisions vary based on system size? If so how should these provisions vary?

IPA Question 18. How should clawback provisions carry over when a system and/or system location is sold?

SEIA recognizes the importance of ensuring system performance to deliver the full benefits of solar energy to the residents of Illinois. However, a clawback mechanism can have a significant impact on the ability of solar developers and customers to transact, and should be implemented

with care. Clawback mechanisms tend to be tailored to specific state needs, and failure to fully consider the ramifications of a clawback mechanism can lead to higher transaction costs and chill customer interest in solar. When developing a clawback mechanism, SEIA urges IPA to focus on an approach that allows the state to verify performance in a rational manner that is not unduly burdensome on IPA, developers, or customers.

Therefore, SEIA recommends that IPA hold a technical conference on this issue to learn about best practices from other states, receive feedback from the local development community, and fully consider its options before moving forward.

Consumer Protections

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

SEIA applauds the IPA’s desire to ensure that consumers have good experiences with their solar systems. Any such role should be in keeping with the limits that state law imposes on the IPA’s jurisdiction over solar companies, commensurate with the risks that solar business practices pose to consumers, and mindful of the extensive body of local, state and federal law that already regulates solar companies. Simply put, SEIA suggests that the IPA should avoid duplicative regulation and oversight and avoid overbroad, unworkable regulations. Instead, the IPA should take a measured approach on consumer protection.

Solar consumer protection issues are governed by multiple federal and state consumer protection laws, as well as various local consumer protection laws coupled with a coupled with a complex web of federal, state, and local regulators. Together, these laws and regulators oversee all aspects of the solar industry. SEIA strongly urges IPA Staff to review the overlapping consumer protections already on the books, including:

Federal Laws

| Law/Regulation | What Does it Cover | Government Agency |
|-----------------------|---------------------------|--------------------------|
|-----------------------|---------------------------|--------------------------|

| | | |
|---|---|---|
| Federal Trade Commission Act | Unfair and deceptive advertising, marketing and sales practices | FTC |
| Consumer Leasing Act | Solar lease agreement disclosures and structure | FTC |
| FCC's Telemarketing Rules | Telemarketing activity | Federal Communications Commission (FCC) |
| Telephone Consumer Protection Act | Telemarketing activity | FCC |
| Truth in Lending Act | Disclosures in connection with loans for solar energy systems | CFPB and FTC |
| Dodd-Frank Wall Street Reform and Consumer Protection Act | Unfair, deceptive or abusive trade practices in connection with any solar financing | CFPB |
| CAN-SPAM ACT | Email solicitations | Federal Trade Commission (FTC) |
| Electronic Funds Transfer Act | Electronic payments made pursuant to any solar agreements | FTC |
| Electronic Signatures Act | Electronic signatures used in any solar agreements | Federal Reserve Board |
| Equal Credit Opportunity Act | Anti-discriminatory lending practices | Consumer Financial Protection Bureau (CFPB) and FTC |
| Fair Credit Reporting Act | Use of credit scores in solar transactions and any credit reporting in connection with making payments on solar loans or leases | CFPB and FTC |
| Magnuson-Moss Warranty Act | Solar warranties | FTC |
| Gramm-Leach-Bliley Act | Safeguards for any personal information submitted to solar energy companies | CFPB and FTC |
| Servicemembers Civil Relief Act | Protect Servicemembers from adverse action in connection with financing extended for solar financing | US Department of Justice |

State Laws

| Section | What Does it Cover | Government Agency |
|----------------|---|--------------------------|
| 815 ILCS 408 | How Sale Prices must be advertised and applicable disclosures | Attorney General |

| | | |
|------------------------|--|------------------|
| 815 ILCS 413 | Telephone Solicitations | Attorney General |
| 815 ILCS 505 | Consumer Fraud and Deceptive Business Practices | Attorney General |
| 815 ILCS 510/1 et seq. | Deceptive trade practices, including representations about sponsorship | Attorney General |
| 815 ILCS 511 | Email Solicitations | Attorney General |
| 815 ILCS 517 | Internet caller identification | Attorney General |
| 815 ILCS 530 | Safeguarding of consumers' personal information | Attorney General |

The solar industry, led by SEIA, has engaged in substantial consumer protection efforts that should inform the IPA’s deliberations, as these efforts represent industry-vetted proposals that can be easily adopted by most solar companies. In 2015, SEIA launched its Consumer Protection Committee (CPC), an active group made up of leading legal experts in solar and consumer law. The CPC has produced a robust set of consumer protection materials for consumers, industry, and other stakeholders. All consumer protection materials are available for free to the public at www.seia.org/consumers. SEIA and its CPC work collaboratively with governments to ensure that consumers understand the residential solar transaction.

The SEIA Residential Consumer Guide to Solar Power summarizes options for going solar, tips on evaluating whether one’s home is right for solar, and key questions to ask a company. SEIA has published a Spanish-version of the guide. A community solar version of the guide was released as well as one for landowners looking to lease their property to solar developers. SEIA adopted model lease and PPA contracts created by a National Renewable Energy Laboratory (NREL) working group. The contracts are clear and complete, provide standardized language, and still give companies flexibility to innovate.

SEIA’s lease, PPA, and system purchase disclosure forms summarize key terms in an agreement so that consumers can easily compare and understand offers.

The heart of SEIA’s consumer protection work is the SEIA Solar Business Code (“SEIA Code”) that all SEIA members must abide by and nonmembers are free to adopt. The SEIA Code lists

laws that companies need to be familiar with and has rules on advertising, marketing and consumer interactions, and contract terms. Further the SEIA Code applies to both rooftop and Community Solar companies. SEIA is in active discussions with Illinois Solar Energy Association and CCSA about how they can adopt to the SEIA Code.

To enforce the SEIA Code, there is a complaint resolution process where the public can submit a complaint about a solar-company (member or non-member) and SEIA will work to get the complaint resolved. The complaint process is designed to supplement government regulation, not supplant it. If a complaint alleges criminal conduct or other issue best handled by government regulators, SEIA passes that complaint onto the appropriate government agency.

Given that the industry is still nascent in Illinois, SEIA cautions the IPA against implementing requirements that make compliance difficult or cost-prohibitive or effectively favor one product over another. Instead, the IPA should take an incremental, targeted approach to consumer protection. Specifically, the IPA should consider implementing the disclosure forms based on SEIA's own disclosure forms.

Further, with the number of consumer protection regulations and regulators, one potentially helpful role of the IPA is to serve as a "clearinghouse" for consumer complaints. Upon receipt and review of a complaint, the IPA can refer the consumer to the appropriate entity for resolution. The IPA can develop a fact sheet for consumer-facing staff regarding who to turn to in case an issue arises. Such fact sheet can also be hosted on the IPA's website. This approach reduces time and confusion in addressing consumer queries and minimize any strain on IPA resources.

Finally, the IPA should explore information sharing with industry stakeholders. Through information sharing all parties will better understand emerging issues and can direct resources at those issues, such as compliance education. This allows all parties to efficiently use their limited resources to help protect consumers.

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

SEIA supports the use of disclosure forms in transactions and urges the IPA to use the SEIA disclosure forms as a model for any required form. The forms were developed over a year and went through a significant vetting process to ensure clarity, usability, and completeness. The forms can aide consumer understanding about solar transactions and provide another opportunity outside of the solar contract or sales process for a consumer to review key terms. Any company offering a lease, PPA, or system sale can use the forms. And states like New Mexico, Nevada, and Florida to some degree used the SEIA forms to develop state disclosure requirements. Further, Nevada provides a list of information that must be included in a contract, cover page, and disclosure form, but companies may continue to create their own materials following the outline in the law. This approach may also be considered. Attached are copies of SEIA’s disclosure forms for the IPA’s review.

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

SEIA cautions against overbroad regulations and recommends that the IPA look to states like Florida, Nevada, and New Mexico which have adopted reasonable approaches to consumer protection. Each state has recently passed consumer protection bills that require residential solar companies to provide a disclosure form -based on the SEIA disclosure forms- as opposed to implementing expansive, unnecessary rules. In fact, Florida and New Mexico originally introduced expansive bills before passing more measured bills.

D. COMMUNITY SOLAR

Geographic Considerations

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

The IPA should not put any additional restrictions on the location of subscribers for community solar projects except that the subscribers must be within the same utility territory as the project. Doing so will distort the market and make community solar participation more difficult for certain segments of the population. If locational requirements are enforced, developers will

gravitate towards developments in densely populated areas so they can maintain the required level of subscribership to make the project financeable. This could unintentionally exclude rural participants altogether. Furthermore, some areas may not have enough space for project development and customers in those areas would be unintentionally excluded from participation.

There should be no further restrictions on the location of subscribers for community solar projects other than to be within the utility territory.

IPA Question 2. How can geographic diversity be ensured?

We do not recommend the IPA put any additional geographic restrictions or conditions around community solar beyond having separate blocks for each utility. The blocks for each utility should correspond to the utility's portion of the overall load. Projects in muni or coop areas should participate in the block program of the closest utility. Some geographic diversity will happen naturally because of interconnection limitations. Furthermore, community solar projects qualify for the DG smart inverter rebate, and that tariff will eventually create locational values that will further incent geographic diversity. The IPA is required to review and revise the long-term plan at least biennially, and we suggest the IPA make minor adjustments during this process if market gaps occur.

Project Application Requirements

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

We recommend that community solar projects have the same block application requirements as DG projects, except without the customer offtake agreement. Distributed generation projects have an inherent off-take customer so a signed off-take agreement is not difficult and should be required for block application. Community solar projects have various business models and the IPA should not pick one over the other. Some projects will source local community subscribers before building a project, some projects will be marketed after they are built. Therefore, the IPA should not require a customer off-take agreement for block application. However, the project should provide subscribership information before being paid for the RECs.

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

In passing the Future Energy Jobs Bill the Illinois General Assembly balanced multiple priorities: creating a robust market while ensuring access to all at the lowest price. Co-location can help with all of these priorities, and therefore we recommend that the IPA allow co-location of community solar projects, but also limit the number to 4-5 projects. Specifically, co-location can help reduce permitting, zoning, and interconnection costs which helps reduce the REC price required to make the project viable, and will in turn make subscription prices more attractive. It can also help encourage additional development in urban areas where limited, but larger, plots of land are available for development or where interconnection capacity is available. This will help communities that want to invest in projects within their own borders do so at a lower cost. There is sufficient capacity within the community solar requirement to allow for some co-location while still maintaining the “community” aspect of the program.

Community Solar Blocks

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

The community solar blocks should be similar to the distributed generation blocks. To reach the 2020 milestone, we recommend 4 blocks: an initial, larger block followed by 3 equally sized blocks. We do not recommend any carve-outs within the block, but rather an adder approach for residential subscriber projects (see question 11 below). The IPA should accept projects on a first-come, first-serve basis. Prioritizing projects within the queue based on specific qualifications will open up the entire program to subjectivity and will skew the market. The IPA is required to review and revise the long-term plan at least biennially, and we suggest the IPA make minor adjustments then if it finds that there are significant market gaps.

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

There are significant costs associated with acquiring and maintaining subscribers, and these costs are higher for residential customers than for commercial customers. Specifically, it is more difficult to find and bill residential customers, and it is often more difficult to maintain residential subscribers. Individuals move out of state much more often than businesses. Residential customers are also riskier, and as such make projects harder to finance.

Therefore, we recommend that the IPA use an adder approach to provide a higher REC value to residential community solar projects. The IPA should calculate the approximate costs for acquiring and maintaining residential subscribers and offer adders: one for projects that have at least 50% residential subscribers, and perhaps one for projects that have at least 75% residential subscribers. We recommend that the IPA ask for industry input and feedback on what these costs might be on a project-by-project basis.

At the time of application, and after meeting other application requirements, the project developer would tell the IPA which category it will be in. The developer would then show proof of the required level of residential subscribership prior to receiving a REC payment.¹¹ To ensure that projects meet these requirements in the long-term, the IPA should require an annual self-certification from the project owner. The IPA should audit 10% of the certifications for compliance. If projects are found not to meet eligibility requirements, owners should have 3 months to come into compliance, otherwise clawback provisions would kick in.

Similarly, most community solar projects will have some level of churn over the life of the project. Furthermore, the law specifically says that community solar projects will be paid for

¹¹ Alternatively, IPA may consider the initial proof of subscribership be based on a portion of the project – 25-40%, representing the anchor tenant(s). Subsequent REC payments would then be required for higher thresholds (e.g., 75% for second REC payment; 95% for third and thereafter). Additionally, the residential/small commercial subscription could be treated as “reserved” capacity.

RECs from subscriptions. This both gives the developer an incentive to keep his project fully subscribed, but also provides a challenge to the IPA to enforce. To minimize the administrative burden on the IPA, we recommend that prior to receiving payment the project developer must prove that 90% of the project is subscribed, and would receive payment for the full output of the system.¹² The owner should annually self-certify that the subscriber level is above 90% to remain compliant. The IPA should audit 10% of certifications and if a project is found to be in violation, the owner would have 3 months to comply before clawback provisions kick in. This allows for projects to have some level of churn without ruining the financial viability of the project.

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

The value proposition for onsite DG over community solar is already more attractive to most customers, and the IPA should not try to overcorrect. While community solar projects might have economies of scale and qualify for the DG inverter rebate, onsite DG has additional benefits. Onsite DG customers can directly offset some of their usage, and residential DG customers also get full retail rate net metering for any net production. DG C&I customers can offset some of their transmission and distribution costs with behind-the-meter projects that they cannot do through a community solar project.

Development Milestones

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

No, the time allowed for development and available extensions should be the same as for comparably sized DG systems. See SEIA recommendations in Project Development Process section.

¹² It should be noted that there are varying views in our membership as to the appropriate initial subscription level prior to the first payment. Some developers recommend a 25-40% initial subscription requirement to enable a project to be operating and to receive the first payment. There is concern that projects requiring potentially hundreds of customers would be at a disadvantage compared to those targeting just a handful of commercial entities at a 90% subscription level requirement. Under this approach, the subscription threshold should rise over time and be a requirement for receiving future REC payments – e.g., 75% subscribed after first year of operation; 95% after second year and thereafter.

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

As mentioned in previous answers, we recommend strong requirements for block application that minimize the need for milestones. The only milestone we recommend is that the project developer demonstrate a suitable level of subscribership before receiving a REC payment. Please also see Question 6 for our suggestions on how to monitor subscriber levels throughout the program.

Residential versus Commercial Interest

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

SEIA recognizes and supports IPA's obligation to ensure robust opportunities for participation of residential customers under the statute. SEIA member companies are interested in extending the opportunity to go solar to residential and small commercial customers through community solar. SEIA believes this is best achieved when multiple business models can flourish and competition is robust, giving customers choice, attracting a diverse customer base, and serving customers at least cost. However, SEIA also recognizes that *robust* participation requires that small customers have a meaningful opportunity to participate in the program, and that a program primarily subscribed by large customers would not satisfy the requirement.

SEIA's members have discussed two primary approaches to fulfilling the statutory requirement to enable robust residential participation: 1) an adder for residential customers to encourage residential participation and 2) a minimum requirement for residential customers. While both approaches present pros and cons, on balance SEIA supports the use of an adder to incentivize residential customer participation, rather than a carve-out that mandates participation. SEIA believes this approach will spur robust residential customer participation in the community solar program while enabling a diverse set of business models to flourish.

SEIA member companies note that the adder approach has been successful at attracting residential subscribers in Massachusetts and New York. *For more specifics see Joint Solar Company comments.* SEIA member companies are concerned that a minimum requirement for small customers would raise the overall cost of the entire program, rather than directing funds to

some part of the market (the adder-based projects) while allowing other, less expensive projects to also flourish. A policy that locks in the entire "community solar" bucket into higher-cost projects could end up undercutting other sectors or leading to non-achievement of the statutory goals. Additionally, SEIA is concerned that a per-project requirement could prescribe a single business model for the Illinois community solar market, reducing innovation and reducing the types of partnerships and projects that can be developed in Illinois.

However, SEIA would also like to flag for IPA that many of its members do not support the majority position discussed above, and instead support a mandatory minimum requirement for residential customers. These members are concerned that an adder will not be able to "ensure" robust participation among small customers. *For more specifics, see comments of Coalition for Community Solar Access (CCSA).*

SEIA recognizes that this issue is central to achieving IPA's statutory goals, and is interested in extending solar to all customer types, including small commercial and residential. For the reasons stated above, SEIA supports achieving this goal with an adder to incentivize small customer participation, rather than a mandatory minimum. However, SEIA recognizes this is an important issue that may merit further consideration, and looks forward to discussing the matter with IPA and other stakeholders in the coming weeks.

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

If the IPA is going to adopt the adder approach, the IPA should set the base community solar REC price based on an all commercial subscriber project. The IPA should then estimate the additional cost needed for customer acquisition and replacement, billing and financing, among other things, for residential subscribers, and set an adder for projects that have 50% residential/50% commercial off-takers. The IPA could also have another adder for 75% residential/25% commercial off-takers, however we recommend the IPA limit the number of adders to keep the program simple.

Project developers should certify at the time of application whether they will qualify for the adders. We do not recommend that community solar projects have PPA or off-take agreements in place at the time of block application, but developers should provide that information to prove that the project qualifies for the adder before REC payments are made.

To ensure that projects remain at the incentive level they applied for, developers should annually self-certify that they are maintaining the corresponding level of residential subscribers. The IPA should randomly audit 10% of certifications for verification. Clawback provisions kick in if the IPA finds that the project does not meet the correct level of residential subscribers.

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

We do not recommend any differences for application. As mentioned in previous questions, applicants should have binding site control, a signed interconnection agreement and all non-ministerial permits in hand. This will ensure that only viable projects get in the queue. All projects must show subscribership before receiving a REC payment.

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

The adder approach we recommend above should be sufficient to create diversity within the market and we don't recommend any additional carve-outs, limitations or considerations be put on the program. The IPA will revise the long-term plan at least biennially and can adjust if anomalies arise. We look forward to continued engagement with IPA and other stakeholders.

SEIA® SOLAR PPA DISCLOSURE

This disclosure is designed to help you understand the terms and costs of your purchasing power from a solar electric system ("System"). It is not a substitute for the power purchase agreement ("PPA") and other documents associated with this transaction. All information presented below is subject to the terms of your PPA.

Read all documents carefully so you fully understand the transaction.
For more information on being a smart solar consumer please visit www.seia.org/consumers.

| | | |
|---|--|---|
| PROVIDER: Address: Tel.: License # (if applicable): Email: | INSTALLER: Address: Tel.: State/County Contractor License #: Email: | WARRANTY/MAINTENANCE PROVIDER: (If Different from Installer or Provider) Address: Tel.: License # (If applicable) Email: |
|---|--|---|

CUSTOMER:
Customer ID:
System Installation Address:
Customer Mailing Address:
Email:

*** NOTE: YOU ARE ENTERING INTO AN AGREEMENT TO PURCHASE POWER, NOT TO PURCHASE THE SYSTEM. YOU WILL NOT OWN THE SYSTEM INSTALLED ON YOUR PROPERTY.**

| Electricity Rate & Term (A) | Amount Due Up-Front (B) | Other Possible Charges (C) |
|---|--|--|
| <input type="checkbox"/> Your initial rate per kilowatt-hour (kWh) for the electricity produced is \$_____. Your monthly payments will be the amount of energy the System produces times the above rate. <input type="checkbox"/> You have a fixed monthly payment PPA. Your monthly payment during the first year of the PPA is \$_____. <input type="checkbox"/> Your electricity rate is subject to other factors. See Box R for more information. Your estimated first year production: _____ kWh The initial term of your PPA: <input type="checkbox"/> _____ Years <input type="checkbox"/> _____ Months Incentives included in your rate per kilowatt-hour (kWh) or monthly fixed fee: <input type="checkbox"/> None <input type="checkbox"/> _____ _____ See Box F , "PPA Payment Escalator", for factors that may affect the amount of your monthly payments. | Amount you owe at PPA signing: \$ _____ Amount you owe at the commencement of installation: \$ _____ Amount you owe at the completion of installation: \$ _____ Total up-front payments you owe: \$ _____ | Other charges you may have to pay under your PPA: Late Charge: <input type="checkbox"/> If a payment is more than _____ days late, you will be charged \$_____ OR <input type="checkbox"/> Late payments accrue interest at _____% annually not to exceed the maximum allowable by law Estimated System Removal Fee: \$ _____ UCC Notice Removal and Re-filing Fee: If you refinance your mortgage, you may have to pay \$ _____ Returned Checks: If any check or withdrawal right is returned or refused by your bank, you may be charged: \$_____ (or a lower amount if required by law) Non-Connection to Internet: If you do not maintain a high-speed internet connection, you will be charged a monthly fee of \$_____ and/or your monthly payments may be based upon estimates. Non-connection may affect any guarantee. See Box M . Automatic Bank Withdrawals (ACH): [\$_____ per month fee for not paying using automatic bank withdrawals] OR [\$_____ per month discount if you pay using automatic bank withdrawals] |

| Number of Monthly Payments (D) | When Payments Are Due (E) | PPA Payment Escalator (F) |
|-----------------------------------|---|---|
| Number of monthly payments: _____ | The first payment on your PPA is due on the _____ day of the first calendar month after your System is interconnected. You will receive: <ul style="list-style-type: none"> <input type="checkbox"/> Electronic Invoices (sent to your email address above) <input type="checkbox"/> Paper Invoices (sent to your U.S. mail address above) | Your PPA <input type="checkbox"/> HAS <input type="checkbox"/> DOES NOT HAVE a payment escalator. If your PPA HAS a payment escalator: Your electricity rate will increase: <ul style="list-style-type: none"> <input type="checkbox"/> Annually <input type="checkbox"/> Other _____ Your electricity rate will increase by the following amount _____% The first electricity rate increase will occur in _____, 20__ or with your 13 th payment, whichever comes later. |

Site & Design Assumptions for your PPA (G)

- Estimated size of System in kilowatts: _____ (kWdc)
- Estimated gross annual electricity production in kilowatt-hours from the System in the first year of the PPA: _____ (kWh)
- Estimated annual System production decrease due to natural aging of System: _____%
- Estimated System electricity production for the entire initial term of your PPA: _____ (kWh)
- System location on your property: _____
- System **WILL** **WILL NOT** be connected to the electric grid
- At the time of installation, your local utility **DOES** **DOES NOT** credit you for excess energy your System generates. The rules applying to such credit are set by your jurisdiction.

Security Filings (H)

Provider **WILL** **WILL NOT** place a lien on your home as part of entering the PPA.
 Provider **WILL** **WILL NOT** file a fixture filing or a UCC-1 on the System. The UCC-1 is a public filing providing notice that Provider owns the System, but is **not** a lien.

Repair & Maintenance (I)

“System maintenance” refers to the upkeep and services required or recommended to keep your System in proper operation. System maintenance **IS** **IS NOT** included for _____ years by _____ (e.g., Installer, Maintenance Provider).

“System repairs” refers to actions needed to fix your System if it is malfunctioning. System repairs **ARE** **ARE NOT** provided by the _____ (e.g. Installer, Other).

Please review your PPA for additional information about any warranties on the System installation and equipment. Certain exclusions may apply. Note that equipment warranties for hardware are not required to include labor/workmanship.

Roof Warranty (J)

Your roof **IS** **IS NOT** warranted against leaks from the System installation for _____ years by _____ (e.g. Provider, Installer, Other).

Your roof **IS** **IS NOT** warranted against leaks caused by removal of the System for a period of _____ years following System removal. Any portions of your roof impacted by the System **WILL** **WILL NOT** be substantially returned to their original condition following the removal of the System (ordinary wear and tear excepted).

Transferring Your PPA and Selling Your Home (K)

If you sell your home, you **MAY** **MAY NOT** transfer the PPA to the purchaser(s) of your home. If you may transfer the PPA, the transfer will be subject to the following conditions:

- Credit check on the purchaser(s)
- Minimum FICO score requirement: _____
- Transfer fee of \$ _____
- Assumption of PPA by purchaser(s)
- Other _____

If you sell your home, you **ARE** **ARE NOT** permitted to move the System to a new home.
 You may also have the options to purchase the System or prepay some or all of the PPA balance as part of or prior to a transfer.

Transfer of Obligations by Provider (L)

The PPA may be assigned, sold or transferred by Provider without your consent to a third-party that will be bound to all the terms of the PPA. If such a transfer occurs, you will be notified if this will change the address or phone number to use for PPA questions, payments, maintenance or service requests.

System Guarantee (M)

In terms of your full System, Provider is providing you with a:

- System performance or electricity production guarantee
- Other type of System guarantee
- No System guarantee

You may have additional guarantees or warranties in addition to those that cover the entire System.

Utility and Electricity Usage/Savings Assumptions (N)

You **HAVE** **HAVE NOT** been provided with a savings estimate ("Estimate") based on your PPA.

If you HAVE been provided with an Estimate, Provider states the following:

Provider **IS** **IS NOT** guaranteeing these savings.

Provider **IS** **IS NOT** using savings calculations that conform to the *SEIA Solar Business Code*. See **Box Q** or www.seia.org/code.

Your Estimate was calculated based on:

- Your estimated prior electricity use
- Your actual prior electricity use
- Your estimated future electricity use
- Any escalator in your PPA rate

Your Estimate assumes the following:

- Years of electricity production from the System: _____
- A current estimated **utility electricity rate** of _____ [cost per kilowatt-hour] during the first PPA year with estimated increases of _____ percent annually. Provider based this estimate on the following source(s): _____
- Your utility will continue to credit you for excess energy your System generates at **ESTIMATED FUTURE** **CURRENT** utility electricity rates.

NOTE: It is important to understand that utility rates may go up or down and actual savings may vary. Historical data are not necessarily representative of future results. For further information regarding rates, you may contact your local utility or the public regulation commission. Tax and other state and federal incentives are subject to change or termination by executive, legislative or regulatory action, which may impact savings estimates. Please read your PPA carefully for more details.

Renewable Energy Certificates (RECs) (O)

Any renewable energy certificates or credits (RECs) from producing renewable solar energy with the System **WILL** **WILL NOT** be assigned to the Provider. If Provider is assigned the RECs, you will not own the RECs to sell, use or claim them, and Provider may sell the RECs to a third party.

Cooling Off Period/ Right to Cancel (P)

In addition to any rights you have under state or local law, you **HAVE** **DO NOT HAVE** the right to terminate this PPA without penalty within _____ [no less than three] business days of _____ by notifying Provider in writing at the above address.

SEIA Solar Business Code (Q)

Provider and Installer **DO** **DO NOT** abide by and agree to be bound by the *SEIA Solar Business Code* (www.seia.org/code) and its complaint resolution process. For more information about the *SEIA Solar Business Code* and complaint resolution process, please visit www.seia.org/consumers or email SEIA at consumer@seia.org.

Additional Disclosures or Terms (R)

Individual Completing this Form:

Name: _____ Signature: _____

Title: _____ Company: _____ Date: _____

SEIA® SOLAR LEASE DISCLOSURE

This disclosure is designed to help you understand the terms and costs of your lease of a solar electric system ("System").
It is not a substitute for the lease ("Lease") and other documents associated with this transaction.
All information presented below is subject to the terms of your Lease.

Read all documents carefully so you fully understand the transaction.
For more information on being a smart solar consumer visit www.seia.org/consumers.

| | | |
|---|--|--|
| LESSOR: Address: Tel.: License # (if applicable): Email: | INSTALLER: Address: Tel.: State/County Contractor License #: Email: | WARRANTY/MAINTENANCE PROVIDER: (If Different from Installer or Provider): Address: Tel.: License # (If applicable) Email: |
|---|--|--|

LESSEE:
Customer ID:
System Installation Address:
Lessee Mailing Address:
Email:

*** NOTE: YOU ARE ENTERING INTO AN AGREEMENT TO LEASE A SOLAR ELECTRICITY GENERATING SYSTEM. YOU WILL LEASE (NOT OWN) THE SYSTEM INSTALLED ON YOUR PROPERTY.**

| Amount & Term (A) | Amount Due Up-Front (B) | Total Estimated Lease Payments (C) | Other Possible Charges (D) |
|---|--|--|--|
| Your monthly payment during the first year of the Lease: \$ _____ The initial term of Lease: <input type="checkbox"/> _____ Years <input type="checkbox"/> _____ Months See Box G , "Lease Payment Escalator", for factors that may affect the amount of future monthly payments. | Amount you owe at Lease signing: \$ _____ Amount you owe at the commencement of installation: \$ _____ Amount you owe at the completion of installation: \$ _____ Total up-front payments: \$ _____ | Total of all your monthly payments and estimated taxes over the course of Lease: _____ Your estimated total Lease payments over the initial term of the Lease excluding taxes are \$ _____ Your estimated total tax payments over the initial term of the Lease are \$ _____ based on estimated average monthly tax payment of \$ _____ Incentives Included in Your Estimated Lease Payments: <input type="checkbox"/> None <input type="checkbox"/> _____ _____ _____ | Other charges you may have to pay under your Lease: Late Charge: <input type="checkbox"/> If a payment is more than _____ days late, you will be charged \$ _____ OR <input type="checkbox"/> Late payments accrue interest at _____% annually not to exceed the maximum allowable by law Estimated System Removal Fee: \$ _____ UCC Notice Removal and Re-filing Fee: If you refinance your mortgage, you may have to pay \$ _____ Returned Checks: If any check or withdrawal right is returned or refused by your bank, you may be charged: \$ _____ (or a lower amount if required by law) Non-Connection to Internet: If you do not maintain a high-speed internet connection, you will be charged a monthly fee of \$ _____ and/or your monthly payments may be based upon estimates. Non-connection may affect any guarantee. See Box N . Automatic Bank Withdrawals (ACH): [\$ _____ per month fee for not paying your Lease using automatic bank withdrawals] OR [\$ _____ per month discount if you pay your Lease using automatic bank withdrawals] Other: You may be charged \$ _____ for _____ |

| Number of Lease Payments (E) | When Payments Are Due (F) | Lease Payment Escalator (G) |
|---------------------------------|--|--|
| Number of Lease payments: _____ | The first payment on your Lease is due on the _____ day of the first calendar month after your System is connected. You will receive: <ul style="list-style-type: none"> <input type="checkbox"/> Electronic Invoices (sent to your email address above) <input type="checkbox"/> Paper Invoices (sent to your U.S. mail address above) | Your Lease <input type="checkbox"/> HAS <input type="checkbox"/> DOES NOT HAVE a payment escalator. If your Lease HAS a payment escalator: <p>Your Lease payment will increase:</p> <ul style="list-style-type: none"> <input type="checkbox"/> Annually <input type="checkbox"/> Other _____ <p>Your Lease payment will increase by the following amount _____%</p> <p>The first Lease payment increase will occur in _____, 20__ or with your 13th payment, whichever comes later.</p> |

Site & Design Assumptions for your Leased System (H)

- Estimated size of the System in kilowatts: _____ (kWdc)
- Estimated gross annual electricity production in kilowatt-hours (kWh) from your leased System in the first year of the Lease: _____
- Estimated annual System production decrease due to natural aging of the System: _____%
- System location on your property: _____
- System WILL WILL NOT be connected to the electric grid
- At the time of installation, your local utility DOES DOES NOT credit you for excess energy your System generates. The rules applying to such credit are set by your jurisdiction.

Security Filings (I)

Lessor WILL WILL NOT place a lien on your home as part of entering the Lease.

Lessor WILL WILL NOT file a fixture filing or a UCC-1 on the System. The UCC-1 is a public filing providing notice that Lessor owns the System, but is **not** a lien.

System Maintenance & Repairs (J)

“System maintenance” refers to the upkeep and services required or recommended to keep your System in proper operation. System maintenance IS IS NOT included for _____ years by _____ (e.g., Installer, Maintenance Provider).

“System repairs” refers to actions needed to fix your System if it is malfunctioning. System repairs ARE ARE NOT provided by the _____ (e.g. Installer, Other).

Please review your Lease for additional information about any warranties on the System installation and equipment. Certain exclusions may apply. Note that equipment warranties for hardware are not required to include labor/workmanship.

Roof Warranty (K)

Your roof IS IS NOT warranted against leaks from the System installation for _____ years by _____ (e.g. Provider, Installer, Other).

Your roof IS IS NOT warranted against leaks caused by removal of the System for a period of _____ years following System removal. Any portions of your roof impacted by the System WILL WILL NOT be substantially returned to their original condition upon the removal of the System (ordinary wear and tear excepted).

Transferring Your Lease and Selling Your Home (L)

If you sell your home, you MAY MAY NOT transfer the Lease to the purchaser(s) of your home. If you may transfer the Lease, the transfer will be subject to the following conditions:

- Credit check on the purchaser(s)
- Minimum FICO score requirement: _____
- Transfer fee of \$ _____
- Assumption of Lease by purchaser(s)
- Other _____

If you sell your home, you ARE ARE NOT permitted to move the System to a new home.

You may also have the options to purchase the System or prepay some or all of the Lease balance as part of or prior to a transfer.

Transfer of Obligations by Lessor (M)

The Lease may be assigned, sold or transferred by Lessor without your consent to a third-party that will be bound to all the terms of the Lease. If such a transfer occurs, you will be notified if this will change the address or phone number to use for Lease questions, payments, maintenance or service requests.

System Guarantee (N)

In terms of your full System, Lessor is providing you with a:

- System performance or electricity production guarantee
- Other type of System guarantee
- No System guarantee

You may have additional guarantees or warranties in addition to those that cover the entire System.

Utility and Electricity Usage/Savings Assumptions (O)

You **HAVE** **HAVE NOT** been provided with a savings estimate ("Estimate") based on your Lease.

If you HAVE been provided with an Estimate, Lessor provides the following:

Lessor **IS** **IS NOT** guaranteeing these savings.

Lessor **IS** **IS NOT** using savings calculations that conform to the *SEIA Solar Business Code*. See **Box R** or www.seia.org/code.

Your Estimate was calculated based on:

- Your estimated prior electricity use
- Your actual prior electricity use
- Your estimated future electricity use
- Any escalator in your monthly Lease price

Your Estimate assumes the following:

- Years of electricity production from the System: _____
- A current estimated **utility electricity rate** of _____ [cost per kilowatt-hour] during the first Lease year with estimated increases of _____ percent annually. Lessor based this estimate on the following source(s): _____
- Your utility will continue to credit you for excess energy your System generates at **ESTIMATED FUTURE** **CURRENT** utility electricity rates

NOTE: It is important to understand that utility rates may go up or down and actual savings may vary. Historical data are not necessarily representative of future results. For further information regarding rates, you may contact your local utility or the public regulation commission. Tax and other state and federal incentives are subject to change or termination by executive, legislative or regulatory action, which may impact savings estimates. Please read your Lease carefully for more details.

Renewable Energy Certificates (RECs) (P)

Any renewable energy certificates or credits (RECs) from producing renewable solar energy with the System **WILL** **WILL NOT** be assigned to the Lessor. If Lessor is assigned the RECs, you will not own the RECs to sell, use or claim them, and Lessor may sell the RECs to a third party.

Cooling Off Period/ Right to Cancel (Q)

In addition to any rights you have under state or local law, you **HAVE** **DO NOT HAVE** the right to terminate this Lease without penalty within _____ [no less than three] business days of _____ by notifying Lessor in writing at the above address.

SEIA Solar Business Code (R)

Installer and Lessor **DO** **DO NOT** abide by and agree to be bound by the *SEIA Solar Business Code* (www.seia.org/code) and its complaint resolution process. For more information about the *SEIA Solar Business Code* and complaint resolution process, please visit www.seia.org/consumers or email SEIA at consumer@seia.org.

Additional Disclosures or Terms (S)

[Empty box for additional disclosures or terms]

Individual Completing this Form:

Name: _____ Signature: _____

Title: _____ Company: _____ Date: _____

SEIA® SOLAR PURCHASE DISCLOSURE

This disclosure is designed to help you understand the terms and costs of your purchase of a solar electric system ("System").
It is not a substitute for the contract ("Contract") and other documents associated with this transaction.
All information presented below is subject to the terms of the Contract.

Read all documents carefully so you fully understand the transaction.
For more information on being a smart solar consumer visit www.seia.org/consumers.

To better understand the cost of the electricity produced by your System, consult the separate form,
SEIA® Solar Purchase Disclosure Addendum – Estimated Cost Per kWh.

| | | |
|--|---|--|
| <u>PROVIDER:</u> Address: Tel.: License # (if applicable): Email: | <u>INSTALLER:</u> Address: Tel.: State/County Contractor License #: Email: | <u>WARRANTY/MAINTENANCE PROVIDER</u> (If Different from Installer or Provider): Address: Tel.: License # (If applicable) Email: |
|--|---|--|

| |
|---|
| <u>CUSTOMER:</u> Customer ID: System Installation Address: Customer Mailing Address: Email: *NOTE: YOU ARE ENTERING INTO AN AGREEMENT TO PURCHASE A SOLAR ELECTRICITY GENERATING SYSTEM. YOU WILL OWN (NOT LEASE) THE SYSTEM INSTALLED ON YOUR PROPERTY. |
|---|

| Purchase Price (A) | Payment Schedule (B) | Financing (C) |
|---|---|--|
| Your purchase price: \$ _____ List of any credits, incentives or rebates included in the above purchase price: _____ _____ _____ *NOTE: You may not be eligible for all incentives available in your area. Consult your tax professional or legal professional for further information. | Amount you owe Provider at Contract signing: \$ _____ Amount you owe Provider at the commencement of installation: \$ _____ Amount you owe Provider at the completion of installation: \$ _____ You will make a final payment to Provider at the following time (e.g. interconnection): _____ and for the following amount: \$ _____ | The System: <input type="checkbox"/> WILL be financed <input type="checkbox"/> WILL NOT be financed; or <input type="checkbox"/> Financing of System UNKNOWN to Provider NOTE: If your System is financed, carefully read any agreements and/or disclosure forms provided by your lender. This statement does not contain the terms of your financing agreement. If you have any questions about your financing arrangement, contact your finance provider before signing a Contract. |

Installation Timing (D)**Interconnection Approval (E)**

Approximate Start Date: _____ days from the date the Agreement is signed *or* _____ (date).

Approximate Completion Date: _____ days from the date of the Agreement is signed *or* _____ (date).

YOU are or **PROVIDER** is responsible for submitting a System interconnection application.

Site & Design Assumptions for your Purchase (F)

- Estimated size of System in kilowatts: _____ (kWdc)
- Estimated gross annual electricity production in kilowatt-hours (kWh) from the System in the first year of operation: _____
- Estimated annual electricity production decrease due to natural aging of System: _____%
- System location on your property: _____
- System **WILL** **WILL NOT** be connected to the electric grid.
- At the time of installation, your local utility **DOES** **DOES NOT** credit you for excess energy your System generates. The rules applying to such credit are set by your jurisdiction.

System Maintenance & Repairs (G)

"System maintenance" refers to the upkeep and services required or recommended to keep your System in proper operation. System maintenance **IS** **IS NOT** included for _____ years by _____ (e.g., Installer, Maintenance Provider).

"System repairs" refers to actions needed to fix your System if it is malfunctioning. System repairs **ARE** **ARE NOT** provided by the _____ (e.g. Installer, Other).

Please review your contract for additional information about any warranties on the System installation and equipment. Certain exclusions may apply. Note that equipment warranties for hardware are not required to include labor/workmanship.

Roof Warranty (H)

Your roof **IS** **IS NOT** warranted against leaks from the System installation for _____ years by _____ (e.g. Provider, Installer, Other).

System Guarantee (I)

In terms of your full System, Provider is providing you with a:

- System performance or electricity production guarantee
- Other type of System guarantee
- No System guarantee

You may have additional guarantees or warranties in addition to those that cover the entire System.

Utility and Electricity Usage/Savings Assumptions (J)

You **HAVE** **HAVE NOT** been provided with a savings estimate ("Estimate") based on your Contract.

If you HAVE been provided with an Estimate, Provider states the following:

Provider **IS** **IS NOT** guaranteeing these savings.

Provider **IS** **IS NOT** using savings calculations that conform to the *SEIA Solar Business Code*. See **Box M** or www.seia.org/code.

Your Estimate was calculated based on:

- Your estimated prior electricity use
- Your actual prior electricity use
- Your estimated future electricity use

Your Estimate assumes the following:

- Years of electricity production from the System: _____
- A current estimated **utility electricity rate** of _____ [cost per kilowatt-hour] during the year of System operation with estimated increases of _____ percent annually. Provider based this estimate on the following source(s): _____

Your utility will continue to credit you for excess energy your System generates at **ESTIMATED FUTURE** **CURRENT** utility electricity rates.

NOTE: It is important to understand that utility rates may go up or down and actual savings may vary. Historical data are not necessarily representative of future results. For further information regarding rates, you may contact your local utility or the public regulation commission. Tax and other state and federal incentives are subject to change or termination by executive, legislative or regulatory action, which may impact savings estimates. Please read your Contract carefully for more details.

Renewable Energy Certificates (RECs) (K)

You may sell or assign any renewable energy certificates or credits (RECs) that you own from producing renewable solar energy to a third party (which may be the Installer) depending on the laws of your state. Under terms of the Contract, any RECs created by the System **WILL** **WILL NOT** be assigned to the Provider. If Provider is assigned the RECs, you will not own the RECs to sell, use or claim them, and Provider may sell the RECs to a third party. In some jurisdictions, you may have to surrender some or all of your RECs to receive state, local or utility incentives.

Cooling Off Period/ Right to Cancel (L)

In addition to any rights you have under state or local law, you **HAVE** **DO NOT HAVE** the right to terminate the Contract without penalty within _____ [no less than three] business days of _____ by notifying Provider in writing at the above address.

SEIA Solar Business Code (M)

Provider and Installer **DO** **DO NOT** abide by and agree to be bound by the *SEIA Solar Business Code* (www.seia.org/code) and its complaint resolution process. For more information about the *SEIA Solar Business Code* and complaint resolution process, please visit www.seia.org/consumers or email SEIA at consumer@seia.org.

Additional Disclosures or Terms (N)

Individual Completing this Form:

Name: _____ Signature: _____

Title: _____ Company: _____ Date: _____

SEIA® SOLAR PURCHASE DISCLOSURE ADDENDUM – ESTIMATED COST PER kWh

This form is designed to accompany, not replace, the SEIA® Solar Purchase Disclosure.
It provides an **estimate** of the cost of electricity produced by your solar energy system (System) over the life of the System.

This addendum is not a substitute for your purchase contract, loan or any other documents associated with this transaction.
Information presented below is subject to the terms of your purchase contract.

Read all documents carefully so you fully understand the transaction.

For more information on being a smart solar consumer please visit www.seia.org/consumers

| | | |
|---|--|---|
| PROVIDER: Address: Tel.: License # (if applicable): Email: | INSTALLER: Address: Tel.: State/County Contractor License #: Email: | WARRANTY/MAINTENANCE PROVIDER (If Different from Installer/Provider): Address: Tel.: License # (If applicable) Email: |
|---|--|---|

CUSTOMER:
 Customer ID:
 System Installation Address:
 Customer Mailing Address:
 Email:

COST PER KILOWATT-HOUR

ESTIMATED AVERAGE COST OF SOLAR ELECTRICITY PRODUCED BY YOUR SYSTEM OVER SYSTEM LIFETIME: \$ _____ /kWh
System Characteristics

System Size: _____ kW

Estimated System Lifetime: __ 20 years __ 25 years __ 30 years

Estimated Production in Year 1: _____ kWh

Estimated Average Annual Panel Degradation Rate: ____ %

Costs

Initial System Cost: \$ _____

Total Financing Cost: \$ _____ (if applicable)

Total Operations & Maintenance (O&M) Costs: \$ _____

O&M Costs Include:

Incentives

Federal, State, Local or Utility Incentives/Rebates Included in this Estimate:

Value of Incentive/Rebates Included: \$ _____

Individual Completing this Form:

Name: _____ Signature: _____

Title: _____ Company: _____ Date: _____