Adjustable Block Program Guidebook

Draft - 11/28/18

Table of Contents

Please note: This Draft Guidebook has been released for a stakeholder review and comment process. The Final Guidebook will reflect input from stakeholders and further analysis from the IPA and its Program Administrator, and items are expected to change between this Draft Guidebook and the Final Guidebook. Interested Parties should therefore view this document as advisory at this time.

Section 1: Adjustable Block Program Description

A complete description of the Adjustable Block Program ("ABP" or "Program") can be found in the Illinois Power Agency's Long-Term Renewable Resources Procurement Plan ("Plan"; http://illinoisabp.com/wp-content/uploads/2018/08/Long-Term-Renewable-Resources-Procurement-Plan-8-6-18.pdf). This Section of this Guidebook contains a summary of the Program designed for quick reference; subsequent sections elaborate on various aspects of the Program, including further guidelines not found in the Plan. A Glossary in Section 8 of this Guidebook provides a description of key terms used throughout.

The ABP provides incentives for the development of new photovoltaic distributed generation ("DG") and community solar projects located in Illinois. These incentives are provided through payments made for the Renewable Energy Credits ("RECs") generated by participating projects over their first 15 years of operation. These payments are made through contracts between Illinois electric utilities and Approved Vendors (as described below).

This Guidebook describes the structure of the Program through the end of 2019. In the summer of 2019, the Illinois Power Agency will be updating, as needed, the Long-Term Renewable Resources Procurement Plan (subject to approval by the Illinois Commerce Commission in the latter months of 2019), with any changes taking effect in 2020, and issues addressed within this Guidebook may be subject to change based on changes made to the Plan.

The ABP is administered pursuant to Section 1-75(c) of the Illinois Power Agency Act (20 ILCS 3855), as updated by Public Act 99-0906 (colloquially known as the Future Energy Jobs Act). The Illinois Power Agency is the state agency responsible for the Program's implementation. Day to day administration of the program is the responsibility of the Agency's Program Administrator, InClime, Inc.

In addition to the approval of the Agency's Plan, many other aspects of photovoltaic development and installation in Illinois are under the jurisdiction of the Illinois Commerce Commission. These include the certification of distributed generation installers, interconnection standards, net metering tariffs, and tariffs allowing for a smart inverter rebate for non-residential PV systems.

Block Structure

The core of the Adjustable Block Program is the concept of a "block." A block constitutes a pre-established amount of program capacity available for a certain project type at a transparent, administratively set REC price or prices, with prices differing slightly depending on project attributes. Blocks are intended to create a progression from one price level to another based on the response of the market. A strong response from the market will result in a rapid progression to a lower price level, for example, while a weak response could elicit an increase in incentives if necessary to facilitate market growth.

The initial goal for the Adjustable Block program is for participating systems to be delivering 1,000,000 RECs annually by the end of the 2020-2021 delivery year (i.e., May 31, 2021). To achieve that goal, the Program's block structure was originally designed such that entirely filling three blocks per project category (see below for a description of the categories) with new photovoltaic projects should result in meeting the program goal of 1 million RECs per year by the end of 2020-2021. However, under the Commission's April 3, 2018 Order approving the Plan, the Agency was required to withhold 25% of program capacity (taken entirely from Block 3) for discretionary allocation; consequently, a fourth block from one or multiple program categories will be required to meet this goal.

In future years, if demand in any given category is stronger than anticipated (and, significantly, if funding available through utilities' RPS rider collections), additional blocks could be open to accommodate that demand. (Likewise, if demand is lower in a category, a block may remain open longer than initially planned.) For the upcoming year, the block size, structure, and prices will be reviewed and updated as needed as part of the Plan update in 2019 (to take effect in calendar year 2020), and the Agency tentatively plans to allocate only capacity sufficient to meet the 1,000,000 REC requirement prior to updating its Plan.

Blocks are allocated into two groups by service territory/geographic category:

- Group A: for projects located in the service territories of Ameren Illinois, MidAmerican, Mt. Carmel Public Utility, and rural electric cooperatives and municipal utilities located in MISO.

- Group B: for projects located in the service territories of ComEd, and rural electric cooperatives and municipal utilities located in PJM.

Based on load forecasts, 30% of Program capacity is allocated to Group A and 70% of Program capacity is allocated to Group B.

Within each Group, the blocks are divided by the following Categories:

- 25% of program capacity for DG PV systems up to 10 kW (Small systems)

- 25% for DG PV systems greater than 10 kW and up to 2,000 kW (Large systems)

- 25% for photovoltaic community renewable generation projects (Community Solar)

As discussed above, the remaining 25% is left to the Agency's discretion and will be held in reserve. The Agency intends to allocate this capacity as soon as practicable after evaluating applications received in the initial weeks of the Program's launch. Prior to allocation, the Agency will first assess the available Renewable Resources Budget (accounting for commitments made from the competitive Forward Procurements for RECs from utility-scale wind, utility-scale solar, and brownfield site solar, and the funding limitations created by the end of the budget roll-over period that concludes with the 2020-2021 delivery year), demand in the various Groups/categories, any unexpected barriers to participation, or other factors related to creating a robust and diverse portfolio of projects.

Consistent with Section 1-10 of the IPA Act, all system sizes in the Adjustable Block Program are measured in maximum continuous AC as measured at the inverter.

Transition Between Blocks

Please note that due to high expected initial demand for the ABP, lotteries for community solar and the large DG categories are likely. The lottery procedures (described below) will take precedence over the transition process in the following paragraphs.

Generally speaking, upon or shortly after a block's capacity becoming filled, the next block for that category (with a different price) will open at a price expected to be 4% lower than the previous block. However, as described in a section below, if initial interest is greater than 200% of Block 1 capacity, then a lottery process may be conducted to select the recipients of REC delivery contracts.

For each Group/category, 14 calendar days after Block 1 opens, the number of project applications received will thus be assessed to determine if the aggregate MW nameplate capacity of those projects is greater than 200% of the Block 1 capacity for that Group/category. The program website will show a dashboard of the capacity of applications received, reviewed, and approved during that 14-day period.

If less than 100% of Block 1 capacity for a Group/category has been filled by 14 calendar days after applications open, Block 1 will be held open until 45 calendar days after opening, or until Block 1 is filled, whichever comes last. In other words, if Block 1 is filled after more than 14 days but before 45 days, the block will be held open until 45 total days has elapsed. If Block 1 is not filled within 45 days after opening, the Agency will continue to hold Block 1 open; the Agency will then announce whenever Block 1's capacity allocation is met that Block 1 for the Group/category is full and that it will be held open for an additional 14 calendar days of applications before officially closing.

Any projects submitted into that Group/category after Block 1 closes will be held for approval in Block 2 for that Group/category. The size available in Block 2 in this case will be impacted by the amount previously allocated to Block 1. (For example, if 110% of Block 1 was actually allocated, 90% of Block 2 will be available via the 45-day process described in the paragraph immediately above.) Subsequently, any projects submitted into a Block 2 Group/category after Block 2 has closed will be held for approval in Block 3, and the size available for Block 3 via the 45-day process will be reduced accordingly if the total amount actually allocated to Blocks 1 and 2 exceeds 100% of the planned capacity of Block 1 plus Block 2.

Each of Blocks 2 and 3 similarly would be held open until the later of (i) 45 calendar days after opening, or (ii) 14 additional calendar days after that block is filled.

If the capacity of applications in a Group/category received in the first 14 days is between 100% and 200% of Block 1 capacity (subject to a review of applications), then all of those projects will receive Block 1 pricing, and Block 1 for that Group/category will be considered closed. Block 2 will open for the next projects received, with those projects receiving Block 2 pricing. The capacity available in Block 2 in this case will be impacted by the amount allocated to Block 1. For example, if 130% of planned Block 1 capacity is allocated to Block 1, then 70% of planned Block 2 capacity will be allocated to Block 2. The 45-day clock for Block 2 would then start on the date when the Agency opens Block 2. If the capacity of applications received in the first 14 days is *exactly* 200% of Block 1, then both Blocks 1 and 2 for that Group/category will be considered closed, and Block 3 would then open with the 45-day clock.

Applications for a Group/category combination that do not engage in an initial lottery will be allocated on a first-come, first-served basis until Block 3 is filled. Order will be based on the date a complete application is submitted. Applications submitted in excess of the total capacity of Blocks 1-3 will be ordered and placed on a waitlist pending allocation of discretionary capacity, any potential allocation of additional funds, or removal from the program of previously accepted projects.

The table below shows the amount of nameplate capacity that will be initially allocated to each block for each group and category. As discussed above, the final amount for each block may change to accommodate the soft closing process described above. As a further example, if the initial demand for the Group A, Small DG category in the first 45 days is 30 MW, the final amount of allocated capacity in Block 1 would be 30 MW, and the next block (Block 2) would open with 14 MW of expected capacity available. However, if Group A, Large DG category only had 10 MW of demand in the first 45 days, it would remain open until its 22 MW of capacity were filled (subject to any adjustments in the final 14 days), and then the next 22 MW block for the Group A, Large category would open.

Block Group	Block Category	Block 1	Block 2	Block 3[1]
Group A (Ameren Illinois, MidAmerican, Mt. Carmel, Rural Electric Cooperatives and Municipal Utilities located in MISO)	Small DG	22	22	5.5
	Large DG	22	22	5.5
	Community Solar	22	22	5.5
Group B (ComEd, and Rural Electric Cooperatives and Municipal Utilities located in PJM)	Small DG	52	52	13
	Large DG	52	52	13
	Community Solar	52	52	13
Total		222	222	55.5

These totals leave the Agency with 166.5 MW of discretionary capacity to allocate across the various Group/category combinations for completing the program's first phase (i.e., to meet the initial 2020-2021 goals of 1,000,000 RECs delivered annually through the Adjustable Block Program).

Subject to the conditions outlined above, a project will receive the price of the block that is open at the time the project application is submitted. If a block closes while a project application is being reviewed and the project is not accepted, the capacity associated with that rejected project will be assigned to the next block.

[1] As discussed above, Block 3 volumes have been decreased for consistency with the Commission's Order in Docket No. 17-0838 requiring that the 25% of discretionary capacity be held in reserve. See Docket No. 17-0838, Final Order dated April 3, 2018 at 60.

Should a system in a given block fail to be developed, that system's portion of the block will be forfeited. The volume associated with the forfeited system will be added to the block that is currently open at the price for that block.

The public will be notified of the availability of capacity in each Block via an online dashboard at www.illinoisabp.com.

Note: Lottery procedures (for the circumstance that projects submitted to a Group/category within the first 14 days after project applications open exceed 200% of Block 1 capacity) will be inserted here for the final Program Guidebook; however, they were subject to a separate stakeholder engagement process and a final version of lottery procedures will be forthcoming shortly.

REC Pricing

The following table lists the prices for RECs by each Group, Category, and Block. After Block 3, prices are expected to decline by 4% with each transition to any subsequent blocks if allocated. The Agency will monitor performance during the initial Blocks and may elect to modify the price change between blocks based upon the speed at which each Block is filled.

Block Group	Block Category		Block 1	Block 2	Block 3
Group A (Ameren Illinois, MidAmerican, Mt. Carmel, Rural Electric Cooperatives, and Municipal Utilities located in MISO)	Small DG	≤10 kW	$85.10	$81.70	$78.43
	Large DG	>10 - 25 kW	$78.70	$75.55	$72.53
		>25 - 100 kW	$64.41	$61.83	$59.36
		>100 - 200 kW	$52.54	$50.44	$48.42
		>200 - 500 kW	$46.85	$44.98	$43.18
		>500 - 2,000 kW	$43.42	$41.68	$40.02
	Community Solar	≤10 kW	$96.12	$92.28	$88.58
		>10 - 25 kW	$87.07	$83.59	$80.24
		>25 - 100 kW	$70.95	$68.11	$65.39
		>100 - 200 kW	$60.47	$58.05	$55.73
		>200 - 500 kW	$55.46	$53.24	$51.11
		>500 - 2,000 kW	$52.28	$50.19	$48.18
		Co-located systems exceeding 2 MW in aggregate size	$47.03	$45.15	$43.34
Group B (ComEd, and Rural Electric Cooperatives and Municipal Utilities located in PJM)	Small DG	≤10 kW	$72.97	$70.05	$67.25
	Large DG	>10 - 25 kW	$73.23	$70.30	$67.49
		>25 - 100 kW	$65.61	$62.99	$60.47
		>100 - 200 kW	$53.75	$51.60	$49.54
		>200 - 500 kW	$48.07	$46.15	$44.30
		>500 - 2,000 kW	$44.64	$42.85	$41.14
	Community Solar	≤10 kW	$91.89	$88.21	$84.69
		>10 - 25 kW	$82.82	$79.51	$76.33
		>25 - 100 kW	$66.65	$63.98	$61.42
		>100 - 200 kW	$56.12	$53.88	$51.72
		>200 - 500 kW	$51.09	$49.05	$47.08
		>500 - 2,000 kW	$47.88	$45.96	$44.13
		Co-located systems exceeding 2 MW in aggregate size	$42.59	$40.89	$39.25

Community Solar

Community solar projects will be provided the following adders based on percentage of small subscribers:

Adder	$/REC	
	Group A	Group B
Less than 25% small subscriber	No adder	No adder
25% to 50% small subscriber	$11.17	$10.88
Over 50% to 75% small subscriber	$22.34	$21.77
Greater than 75% small subscriber	$33.51	$32.65

The small subscriber adders will be determined based on the percentage of the project's capacity met through small subscribers' subscriptions, and not the overall number of small subscribers. A community solar project will have to demonstrate a level of small subscribers at the time of energization to receive an adder initially; if it does not meet that level by 1 year after energization, the project will lose its small subscriber adder and will also be subject to a 20% penalty on the contract value. Furthermore, the project will have to maintain the small subscriber subscription levels over time or face payment reductions or collateral drawdowns if the level is not maintained.

A small subscriber is defined as a customer on a residential or small commercial rate class with a subscription of less than 25 kW. Eligible small commercial rate classes for the investor owned utilities are:

-Commonwealth Edison: "watt-hour delivery class" and "small load delivery class"
-Ameren Illinois: "DS-2"
-MidAmerican: "GE", "GD", "GET", "GDT", "GER", and "GDR"

Section 2: Approved Vendors

Approved Vendor registration guidelines were developed under separate stakeholder processes and will be inserted into the final Program Guidebook here. This topic is not open for stakeholder comment at this time.

Section 3: Marketing Guidelines and Consumer Protections

Marketing guidelines were developed under separate stakeholder processes and will be inserted in to the final Program Guidebook here. These topics are not open for stakeholder comment at this time.

Section 4: System Eligibility

System Location

All systems must be entirely physically located in Illinois and interconnected to the distribution level electrical grid of an Illinois investor owned utility or Illinois electric cooperative or municipal electric system. Off-grid systems are not eligible for the Adjustable Block Program. All Distributed Generation systems must be located on the customer side of the customer's electric meter and primarily used to offset that customer's electricity load.

Systems must be built at the location specified in the Part I application. Systems must remain at the approved location for the duration of the 15-year contract and may not be relocated.

Interconnection Date

All systems must have a final interconnection approval (or equivalent from rural electric cooperative or municipal electric utility) date on or after June 1, 2017.

Installer Requirements

System installations must meet the following requirements in to participate in the Adjustable Block Program. These requirements are not waivable for any system, including systems built after June 1, 2017 but before program launch.

1. A system must be installed by a company with current Distributed Generation Installer certification from the Illinois Commerce Commission (https://www.icc.illinois.gov/Electricity/authorities/DistributedGenerationCertification.aspx).
2. A system must be installed by a qualified person(s). The following definition of “qualified person” and the term “install” will be used to evaluate compliance with this requirement:

> **"Qualified person"** means a person who performs installations on behalf of the Distributed Generation Installer certificate holder (as certified by the ICC) and who has completed at least one of the following programs requiring lab or field work and received a certification of satisfactory completion: an apprenticeship as a journeyman electrician from a USDOL-registered or an applicable state-agency-registered electrical apprenticeship and training program; a North American Board of Certified Energy Practitioners (NABCEP) distributed generation technology certification program; an electrical training program for in-house employees established and administered by an electric utility regulated by the Commission; or an Associate in Applied Science degree from an Illinois Community College Board-approved community college program in solar generation technology.
>
> **"Install"** means to complete the electrical wiring and connections necessary to interconnect the new solar project with the electric utility's distribution system at the point of interconnection between the project and the utility. "Install" in this Part specifically does not mean:

- Electrical wiring and connections to interconnect the new solar project performed by utility workers on the utility's distribution system;
- Electrical wiring and connections internal to the new solar project performed by the manufacturer;
- Tasks not associated with electrical interconnection of the new solar project and the utility, including those relating to planning and project management performed by individuals such as an inspector, management planner, consultant, project designer, contractor, or supervisor for the project or their employees.

Expansions

An expansion to an energized system that is already under an ABP contract must be independently metered (with a separate GATS or M-RETS ID) and will be issued a new contract independent from the contract of the original system. The expansion must comply with all program rules in effect at the time the expansion application is submitted. Expansions are subject to the following additional requirements:

1. The expansion will only be compensated up to the maximum 2 MW size limit when added to the original system at that location. For example, if a location already has a 1.9 MW system at that location and a 200 KW system is added, a new contract will only be granted for the estimated production of a 100 KW system.

2. If an expansion would move the total system size from the small DG category into the large DG category, and that category is operating on a waitlist, the expansion would be added to the waitlist in the same manner as a new system in that category while the existing system continues to receive REC payments under the previously contracted terms.

3. The expansion price will be adjusted to take into account the current block price at the size of the combined system minus the price paid to the original system. For example, a 10 kW system in Block 1 Group A initially received $85.10/REC with an estimate that it would produce 100 RECs over the contract period, for a total of $8,510. A 10 kW addition is planned once the small DG and large DG categories in Group A have moved to Block 2. Because the new system with this addition would total 20 kW, the total system size is now in the >10-25 kW size category; for Block 2, Group A, that price is $75.55/REC. Assuming the expansion would also produce 100 RECs over the contract life, a calculation must be performed as if the system were a 20 kW system at the current block price. This value would be 200 RECS * $75.55/REC = $15,110. The previous payment of $8,510 must be subtracted from this value, leaving a total contractual payment of $6,600 for the new expansion. There will be no pro-rating of the time the original system was in operation when making this calculation. The contract term for the original system will remain the same, and the contract term for the expansion will be 15 years from the date the expansion commenced operation.

4. If an expansion is made to an existing system that is not part of the Adjustable Block Program and only the expansion is applying to the Program, then the system size used to determine REC price will be solely the expansion size.

Co-location of DG projects

The total capacity of distributed generation systems enrolled in the Adjustable Block Program at a customer's location will be considered a single system. (For example, three 100 kW systems at a single location will be considered a 300 kW system.) For purposes of determining the system's REC price, a system's location is considered to be a single building (regardless of the number of utility accounts at the location) for rooftop installations, and a single property parcel for ground-mounted systems (if a property had both rooftop and ground-mounted systems, it will be considered a single system). Additionally, systems located on multiple different rooftops on the same parcel will be considered a single system if each system is owned by the same entity or its affiliates.

If two projects on one roof are separately owned and serve to offset the load of separate occupants (residential or commercial) of a building, then in order to have these arrays considered as two separate projects, an Approved Vendor must provide proof that the occupants are not affiliated entities and each has a separate utility meter and separate utility billing.

Co-location of Community Solar Projects

- No Approved Vendor may apply to the Adjustable Block Program for more than 4 MW of Community Solar projects on the same or contiguous parcels (with each "parcel" of land defined by the County the parcel is located in).
- Co-located projects summing to more than 2 MW of Community Solar may be permissibly located in one of two ways:
  - Two projects, of up to 2 MW each, on one parcel; or
  - One project, of up to 2 MW, on each of two contiguous parcels.
- A parcel of land may not have been divided into multiple parcels in the two years prior to the project application (for the Adjustable Block Program), or bid (for competitive procurements) in order to circumvent this policy. If a parcel has been divided within that time period, the requirement will apply to the boundaries of the larger parcel prior to its division.
- If there are multiple projects owned or developed by a single entity (or its affiliates) located on one parcel of land, or on contiguous parcels of land, any size-based adders will be based on the total size of the projects owned or developed on the contiguous parcels by that single entity or its affiliates. Furthermore, the total combined size of projects owned or developed by a single entity (or its affiliates) on contiguous parcels of land may not be more than 2 MW, or more than 4 MW if co-located consistent with the provisions outlined above.
  - "Affiliate" means, with respect to any entity, any other entity that, directly, or indirectly through one or more intermediaries, controls, is controlled by, or is under common control with each other or a third entity. "Control" means the possession, directly or indirectly, of the power to direct the management and policies of an entity, whether through the ownership of voting securities, by contract, or otherwise. Affiliates may not have shared sales or revenue-sharing arrangements, or common debt and equity financing arrangements.

  - "Contiguous" means touching along a boundary or a point. For example, parcels touching along a boundary are contiguous, as are parcels that meet only at a corner. Parcels, however near to each other, that are separated by a third parcel and do not touch along a boundary or a point are not contiguous.
- Projects owned or developed by separate entities (meaning that that they are not affiliates) may be located on contiguous parcels. If there is a naturally good location from an interconnection standpoint, one owner should not be allowed to prevent another owner from developing a project in that location.
- Projects must have separate interconnection points.

Site Control

The Approved Vendor must provide a written binding contract, option, or other demonstration of site control acceptable to the Program Administrator for all projects where the Approved Vendor is not also the project owner and the host.

Site Map

The site map must be provided with each application which shows property boundaries, any structures on the property, and the location of the solar array(s). Roof mounted arrays must include a map showing the location of the solar array(s) on the roof. All electrical improvements that are not co-located with the solar array must also be shown (e.g., trenching from ground mounted arrays to the property power source or upgrades to the transmission system).

Shading Study

A shading study shall be completed for all projects. This can be an onsite shading study performed using shading study software or a person with experience performing such studies.

In order to use the standard capacity factor, a system must meet the Minimal Shading Criteria.

The Minimal Shading Criteria is:

> No obstruction is closer than a distance ("D") of twice the height ("H") it extends above the PV array. All obstructions that project above the point on the array that is closest to the obstruction shall meet this criterion for the array to be considered minimally shaded. Any obstruction located north of all points on the array need not be considered as shading obstructions. Obstructions that are subject to this criteria include:
>
> (a) Any vent, chimney, architectural feature, mechanical equipment, or other obstruction that is on the roof or any other part of the building.
>
> (b) Any part of the neighboring terrain.
>
> (c) Any tree that is mature at the time of installation of the PV system.

(d) Any tree that is planted on the building lot or neighboring lots or planned to be planted as part of landscaping for the building. (The expected shading shall be based on the mature height of the tree.)

(e) Any existing neighboring building or structure.

(f) Any planned neighboring building or structure that is known to the applicant or building owner.

(g) Any telephone or other utility pole that is closer than 30 feet from the nearest point of the array.

REC Quantity Calculation

1. The application portal will automatically calculate the PVWatts estimated production and the standard capacity factors of 16.42% for fixed mount or single axis trackers and 19.32% for dual axis tracking systems. Applicants will be allowed to choose either of these numbers, rounded to the nearest whole REC for their 15-year contract REC delivery amount, or can choose a lower number if their alternative capacity factor determines that a lower number is appropriate. Any arrays with an azimuth greater than 270 or less than 090, a tilt of greater than 80 degrees, or that do not meet the Minimal Shading Criteria may not use the standard capacity factors and must either use the PVWatts estimate or approved alternative capacity factor.

2. Any proposed alternate capacity factor that is calculated using a proprietary third-party software tool will require the Approved Vendor to provide a copy of the third-party software tool with appropriate licenses to the Program Administrator as well as providing all inputs to the tool in a manner which will allow the Program Administrator to replicate the generation claimed. The Program Administrator will accept alternate capacity factors on a case by case basis after reviewing the methodology used to determine such alternate capacity factor.

3. The Administrator will evaluate systems using non-standard technologies such as bifacial panels or seasonally adjusted tilt on a case by case basis.

System Size

1. All system sizes described in this guidebook are AC system size based on the inverter size, i.e. a system with a single 10 kW inverter is considered a 10 kW system even if it has 12 kW of STC DC capacity.

   a. Inverter capacity shall be measured as maximum continuous output.
   b. An inverter shall be connected to a solar panel in order to be considered as part of the AC system size. In the case of microinverters that contain two inverters per unit, only the inverters connected to a panel shall be included in the AC system size.

2. Systems will be limited to a DC capacity of 150% of the AC capacity (for example, a 10 kW AC system can contain only 15 kW in STC DC capacity).

Systems with Battery Backup

All systems which include a battery shall be electrically connected in a manner which ensures that any non-solar generated electricity used to charge the battery is not later metered as solar generated power. This can be done in one of two ways:

a. The meter used to report production is electrically located before the battery charger and does not measure any power that is drawn from the battery bank.
b. A net meter is connected to the system that runs in reverse when any non-solar power, including on-site generator power, is used to charge the battery bank.

This must be an integral part of the physical system design. An inverter which can be configured using software to preclude non-solar charging of the battery bank is not sufficient if that inverter is used as the source of reporting for renewable generation.

Systems that Directly Serve DC Loads

The Agency does not wish to inadvertently prohibit participation in the Program by photovoltaic systems that do not convert the DC electricity produced to AC electricity. However, for the reasons addressed below, the Agency is still in the process of developing standards for allowing Adjustable Block Program participation from DC-only systems.

Certain difficult questions arise in considering how to structure such systems' participation, particularly, how to estimate the system's 15-year REC production for purposes of establishing a contractual delivery obligation. The Plan allows systems to use an alternative capacity factor based upon an analysis using PV Watts or an equivalent tool. This may be challenging, however, given that the alternative capacity factor ordinarily must be multiplied by a system's nameplate capacity (measured based on the inverter size in kilowatts AC), and in a DC-only system, the capacity of solar panels may significantly exceed the inverter size. An alternative approach may be to assume an inverter size equal in size to the DC photovoltaic array: e.g., if such a system has 10 kW DC of panels, the Agency could assume an inverter size of 10 kW AC and then multiply by a standard capacity factor.

The Agency welcomes comment from stakeholders as to manageable standards for allowing participation of such DC-only systems in the Program while complying with the letter and spirit of the Illinois Power Agency Act as well as the Commission's Order in Docket No. 17-0838 (pp. 78-79).

Metering

1. Systems registered in M-RETS must utilize an ANSI C.12 certified revenue quality meter.
2. Systems over 25 kW registered in GATS must utilize a new meter that meets ANSI C.12 standards.
3. Systems over 10 kW and less than 25 kW in size registered with GATS must utilize a meter that meets ANSI C.12 standards. Meters that are refurbished (and certified by the meter supplier) are allowed.
4. Systems of 10 kW in size and below registered with GATS must utilize either a meter that is accurate to +/- 5% (including refurbished and certified meters), or an inverter that is specified by the manufacturer to be accurate to +/-5%. The inverter must be UL-certified and must include either a digital or web-based output display.

5. No system is required to have automated or remote meter reporting capability, although such meters are allowed if they meet the requirements in sections 1-4 above.

6. The Agency is considering allowing systems with DC meters to participate in the Program and is aware that the ANSI Accredited Standards Committee C12 is presently considering creation of a new DC metering standard; however, that standard has not been finalized as of the date of release of this draft Program Guidebook and likely will not have been finalized by the time the Program opens for project applications in January of 2019. As part of the release of this draft Program Guidebook, the Agency invites feedback on what tractable standards the Agency could adopt to allow photovoltaic systems with DC meters to participate in the Program. One possibility raised previously by stakeholders has been to allow any DC meter with a manufacturer's accuracy rating equivalent to the ANSI C.12 accuracy standard for AC meters (± 2%), and the Agency welcomes feedback on this approach or other approaches.

No Partial Systems

All systems entered into the ABP must include the entire output of the system. Any capacity of a system which is not part of the ABP must be separately metered with a separate inverter.

Section 5: Project Applications

Application Process

Batches

All applications will be submitted electronically at illinoisabp.com. Applications will be completed on a project by project basis. However, applications can only be submitted in a batch which must consist of at least 100 kW and no more than 2 MW of capacity. An approved vendor may select from their completed project applications to form and submit a batch. Project applications will only be reviewed once they have been submitted as part of a batch.

A minority-owned, female-owned, or small business may request to submit an initial batch of only 50 kW, with any subsequent batches subject to the standard 100 kW requirement. For purposes of eligibility for submitting a 50 kW initial batch, a "small business" means any for profit entity, independently owned and operated, that grosses less than $4,000,000 per year or that has 50 or fewer full-time employees, with its principal office in Illinois. This status will be requested and approved by the Program Administrator in the Approved Vendor application process.

Application Fee

An application fee equal to $10/kW, not to exceed $5,000, will be required for each project. This application fee will be paid to the Program Administrator at the time the batch is submitted. The application fee payment will be part of the batch submission process and the fee will be automatically calculated by the application portal. Fees may be paid by wire or ACH direct deposit initiated by the applicant using a unique tracking code generated by the application portal in the wire or direct deposit notes section to allow matching of deposits to batch submissions by the Administrator. If the Approved Vendor opts for this payment method, the batch will not be deemed submitted until the application fee is received by the Program Administrator. Approved Vendors will also be offered the ability to request that the Program Administrator withdraw funds from their account via ACH or pay by credit card. The batch will be deemed submitted at the time of submission if either of these methods are used. Credit card payments will be subject to an additional fee of 2.9% of the total payment to account for credit card processing fees and will be limited to no more than $10,000 per month per Approved Vendor.

Application Parts

Applications consist of a Part I and a Part II; each of these parts must be completed for each participating system. The Part I application may be completed when the project is in the planning stage and collects information on a system's planned technical aspects including size, estimated REC production, equipment and installation company. The Part II application is to be completed only when a project has been completed and energized. Only systems that have a completed and approved Part I application that is subsequently approved by the ICC may proceed to the Part II stage.

Once an Approved Vendor has at least 100 kW of Part I applications complete (or 50 kW if applicable) that Approved Vendor can select projects to become part of a batch submitted to the Program

Administrator for approval. The Program Administrator will review each project's application in the batch for compliance with program guidelines and, as needed, request additional information from the Approved Vendor to verify the submitted information and approve the project. An Approved Vendor will be given up to two weeks to cure deficiencies in an application. In the case of continued communication between the Program Administrator and the Approved Vendor, at the Program Administrator's discretion, the cure period may be extended up to two weeks from the last good faith effort to provide the required information.

If, after any attempts to cure deficiencies have been made, 75% or more of the kW volume in a batch is reviewed and approved by the Program Administrator, the Program Administrator will assign the batch (less any projects not approved) to a utility, and prepare the confirmation information (and master contract information if it is the Approved Vendor's first batch) related to that batch.

If less than 75% of the kW volume of a batch is approved by the Program Administrator, the batch will be rejected in its entirety. Batches will be reviewed in the order that they are received. Systems that are reviewed and approved but are in a batch that is rejected may be submitted in a future batch which will be subject to an expedited review process. The application fee for a batch applies only to newly submitted systems in that batch, not to systems that were previously reviewed and approved.

An Approved Vendor that repeatedly submits batches that are rejected may be subject to having its Approved Vendor status reviewed, and possibly terminated.

For Block 1, all batches submitted within 14 days of the program opening will be considered for Block 1. If the total quantity of approved projects submitted in any Block 1 Category or Group exceed 200% of that Block's capacity, a lottery will be held to select projects. The lottery procedure was the subject of a separate stakeholder engagement process and is not be subject to additional stakeholder comments at this time.

The Program Administrator will then submit information about the batch to the Illinois Commerce Commission for approval. The Program Administrator simultaneously will forward the information to the applicable utility.

The Commission meets approximately every two weeks. The Program Administrator will strive to efficiently process approved batches for submittal to the Commission. The Agency understands that Commission practice is that items for consideration by the Commission must be submitted to be placed on its open meeting agenda at least one week prior to each meeting.

When the Program Administrator submits contract information to the Commission for approval, that submittal will include the Program Administrator's recommendation for approval of the batch, with a summary of factors relevant to Plan compliance. Once a batch is approved by the Commission, the applicable utility will execute the contract. The Approved Vendor will then be required to sign the contract within seven business days of receiving it.

Within 30 days after contract execution, a collateral requirement constituting 5% of the value of a system's REC contract must be posted with the utility counterparty in the form of cash or a letter of credit from an underwriter with credit acceptable to the utility. The Approved Vendor may choose for the utility to withhold the collateral amount for each system from the last REC payment for the system (or only REC payment for small systems) in exchange for not needing to maintain the ongoing collateral requirement, but this election may be made only after the project is certified by the Program Administrator as developed and energized.

Development Timelines

Once a contract for a batch has been executed by the Approved Vendor and the utility, projects within that batch must be developed and energized by the following time limits based on the contract execution date:

• Distributed generation projects will be given one year to be developed and energized.
• Community solar projects will be given 18 months to be developed, energized, and demonstrate that they have sufficient subscribers.

A project that is not completed in the time allowed (plus any extensions granted) will be canceled and removed from the schedule on its contract, and the REC volume associated with the project will be eliminated. The Approved Vendor will also forfeit the posted collateral associated with the project.

A project that is not completed in time and deemed canceled may be subsequently included in a future batch submitted by an Approved Vendor, but will be treated as a new system rather than a resubmitted system and will receive a REC price applicable to its category and block open at that time.

Extensions will be granted for the following circumstances:

• An indefinite extension will be granted if a system is electrically complete (ready to start generation) but the utility has not approved the interconnection. The Approved Vendor must document that the interconnection approval request was made to the utility within 30 days of the system being electrically complete, yet not processed and approved.

• A 6-month extension will be granted for documented legal delays, including permitting delays.

• One 6-month extension will be granted upon payment of a refundable $25/kW extension fee for distributed generation systems, and up to two 6-month extensions for community solar projects (the second extension is only for achieving the required subscriber rate, not for project completion and energization, and will require an additional refundable $25/kW fee). The extension fee(s) would be payable to the contracting utility and would be refunded as part of the first (or only for systems up to 10 kW) REC payment.

• The Agency may also, but is not required to, approve additional extensions for demonstration of good cause. The Agency is aware of potential delays in receiving updated interconnection cost estimates (particularly for community solar projects on a crowded feeder queue) that could delay system completion timelines, possibly pushing electrical completion beyond the period contemplated in the contract at no fault of the developer; such delays would qualify as good cause for the approval of an extension.

Part II Submittal Process

Once a system is complete, the Approved Vendor will complete Part II of the application. Part II will consist of uploading information verifying completion of the project and confirming that the specifications have not changed from the Part I application. Systems may change size by no more than +[illegible]% (or less than 1 kW, if 1 kW exceeds 5%) from the Part I application. If the final system size is larger than the proposed system size such that it would cause the system to change from the up-to-10 kW category to the over-10 kW category, the payment terms will be adjusted from the full payment on energization to 20% payment on energization and the balance paid over the next four years. The price per REC will also be changed to the applicable REC price for the over-10 kW category in the block open at the time the system is energized.

For systems over 10 kW, any adders are granted based on the final system size in Part II rather than the initial system size in Part I. A system that is developed at a size smaller than the original application will not be eligible for additional adders.

A project's REC payment is based on the quantity of RECs estimated to be produced by the system, and this amount will be considered the lesser of the estimated production in Part I and Part II of the application. In this way, a system that is built smaller than planned will not benefit from excess REC payments that the final system cannot support as a result of its decreased production estimate. On the opposite side, if a project's final size is larger than the planned size, an increase in the REC payment could present unexpected budget management challenges. An Approved Vendor has the option of canceling and resubmitting a system if the final size is larger than the proposed system or if it desires to have the system change from a distributed generation project to a community solar project, or vice versa. However, the REC price will be that of the Block open at the time of resubmission, not of the original submittal. A new application fee will be required because the Agency will need to review the system design, which would be different from what was originally submitted (e.g., because of the change in system size). If a project is resubmitted and approved, the collateral associated with the original system would be applied to the resubmitted system.

The Agency will reserve the right to request more information on an installation, and/or conduct on-site inspections/audits of projects to verify the quality of the installation and conformance with the project information submitted to the Agency. Projects found not to conform with applicable installation standards and requirements, or projects found not to be consistent with information provided to the Agency, will be subject to removal from the program if the deficiencies cannot be remedied. Likewise, Approved Vendors who repeatedly submit projects that have these problems may be subject to losing their Approved Vendor status.

The Program Administrator will review the Part II application and upon approval will provide a confirmation sheet to the Approved Vendor to include with its invoice to the utility with which it has contracted to sell the RECs from that project. The Program Administrator separately will provide information to each utility covering the details of each completed project.

Energized Systems

Only systems energized on or after June 1, 2017 are eligible for application to the Adjustable Block Program. An Approved Vendor is allowed to submit a Part I application for an already energized system meeting this requirement; however, the Approved Vendor bears the risk that the system does not meet program requirements if marketing, sales, installation, and other development activities occurred prior to the Agency's final publication of Program guidelines. Systems that are already energized will complete the same Part I and Part II process for final approval.

Community Solar Additional Requirements

Part I of an application for a community solar project will require a description of the proposed subscription model (e.g., typical length and structure of contract, economic terms, marketing channels, etc.) and the expected mix of residential and non-residential subscribers. The Agency will assess whether the subscription model will reasonably meet program terms and conditions and will use the subscriber mix to determine which adder, if any, will be awarded to the system, but the final adder (if any) will depend on the subscription level demonstrated once the system completes Part II of its application.

Under Part II of the application, a community solar project will have to demonstrate that it has met a minimum subscription level to be considered energized and eligible to receive payment for RECs. To receive REC payments, at least 50% of the capacity of the project must be subscribed at the time of energization. Such payment will be based upon a project's percentage subscribed at the time of energization. The Approved Vendor will report subscription levels on a quarterly basis during a project's first year. The calculation of the number of RECs for payment will be updated after one year of operation (based on the final quarterly report of that first year) to allow for the acquisition of additional subscribers. A community solar project may request one additional extension, with a non-refundable extension payment of $25/kW, to its energized date if it needs additional time to acquire subscribers.

If a community solar project fails to attract sufficient subscribers by the time of energization, but also meets the definition of a distributed generation project (i.e., is located on-site, behind a customer's meter, and used primarily to offset a single customer's load), it may request to be recategorized as a distributed generation project and receive a REC payment at the lesser of the original price and the price of the distributed generation block open at the time this determination is made. A community solar project that does not meet the definition of a distributed generation project that fails to attract subscribers will not be eligible for this option and would not be eligible for REC payments. Likewise, a proposed distributed generation system may switch to being a community solar project before energization and receive the REC price of the currently open community solar block, and any appropriate adders. In both of these situations, a project may only switch one time.

Required Information
The following information will be required for each Part I and Part II application:

Part I
Note: Every completed disclosure form will create a Part I application with all of the information from the disclosure form already prefilled, eliminating the need for duplicate data entry. Community solar projects will not have completed a disclosure form and will therefore be required to enter this data in the Part I application form.

- Project location and property owner
- Project Owner (if different than property owner)
- Installer name & contact information
- Name of Utility for which the system is interconnected
- Project Type (Residential, Non-residential, Government, Non-Profit, Community Solar)
- Financing Structure (Customer-owned, lease, or PPA) (Not asked for community solar)
- Project Cost (inclusive of material cost, labor cost, permitting cost, other costs)
- Technical Project Information
    - -Ground or Roof Mount?
    - -Number of tracking axes (fixed tilt or tracking?)
    - -Modules: make, model & manufacturer of modules
    - -Inverter: Size, make, model, manufacturer, efficiency
    - -Does this project have a battery-backup?
    - -Meter: make, model, manufacturer. Does the meter meet the ANSI C.12 standard if required by the applicable registry?
    - -Array information (# modules, module power rating, tilt, & azimuth) for each array
    - -System size in DC and AC
- PV Watts (or similar tool) estimate of REC production during 15 year term (auto-calculated by the portal if using PV Watts)
- For Community Solar only:
    - (for purposes of preference in lottery selection) Does the project commit to obtaining 50% small-subscribers?

- Describe the proposed subscription model
- Describe the expected mix of residential and non-residential subscribers
- If the project is in a municipal utility or electric cooperative territory, demonstrate the municipal utility or electric cooperative offers net metering bill credit for community solar projects substantially similar to that offered under Section 16-107.5(l) of the Public Utilities Act as well as purchase of any unsubscribed energy under Public Utilities Regulatory Policies Act of 1978.

• Required Uploads:

1. For all projects:
   - Signed Disclosure Form
   - Shading Study
   - Proof of site control
   - Plot diagram or site-map
   - Proof that the brochure was provided to the customer
2. Additional Uploads for systems over 25 kW:
   - Signed Interconnection Agreement
   - Attestation that all required Non-Ministerial Permits have been obtained, along with a list of all such permits, the issuing authority, and the contact information of responsible person at authority
3. Requirements for systems already energized prior to application:
   - GATS or M-RETS unit ID
   - Uploading of:
     - Certificate of Completion of Interconnection
     - Net metering application approval letter (if applicable)
     - Photographic documentation of installation

Any project that does not meet these requirements will not be considered eligible to receive REC payments; the Approved Vendor will have the option to resubmit the project. However, the resubmittal will be placed at the end of any waitlists that had previously been established for that Group/category, will be at the price of the Block open at the time, and will require a new application fee.

Part II

- Actual system size in both DC and AC (if different than the size submitted in Part I, please re-supply the array information)
- Final 15 year REC production estimate
- Provide description of any other changes made to the project between initial application and the completion of the project
- Interconnection Approval Date and Online Date
- Registry in which the system is registered (PJM-GATS or M-RETS)

-Provide the PJM-GATS or M-RETS unit ID

-Provide the name on the PJM-GATS and M-RETS account

-Provide proof of accepted irrevocable transfer agreement

-Confirm name of installer from Part I (must match the name of a current ICC Certified DG Installer)

-Provide final invoice showing installer. If the system owner is the installer a checkbox can be selected to indicate this.

-Final system cost

-Name of qualified person(s) who conducted the installation

Note that variations of less than 5% (or less than 1 kW, if 1 kW exceeds 5%) in ~~size or~~ capacity and variations in plot placement that impact less than 5% of the total surface area covered by the solar array(s) will not require project reapproval.

- Required Uploads:
  - Certificate of Completion signed by the utility
  - Net metering approval letter (if applicable)
  - Photograph(s) of the project showing all installed modules. Photograph must clearly show each module and must be in JPEG, TIFF, BMP, or PNG format.
  - Photograph(s) of the inverter(s). Photograph must clearly show inverter model number and must be in JPEG, TIFF, BMP, or PNG format.

    - Photograph of the meter (if applicable). Photograph must clearly show current cumulative lifetime meter reading and must be in JPEG, TIFF, BMP, or PNG format.
    - Proof that the project has an irrevocable transfer set-up in the REC tracking registry through either a copy of the irrevocable transfer acceptance email or a screen shot of the irrevocable transfer screen showing the registry certification number of the system.

- For Community Solar only:
    - Proof that minimum subscriber commitments have been met (50% of capacity must be subscribed)
    - Percentage of small subscribers

Section 6: Renewable Energy Credit Management

REC Delivery

1. All systems must be registered in either the PJM-GATS or M-RETS tracking registry. For systems larger than 5 kW, the first REC must be delivered within 90 days of the date the system is energized and registered in GATS or M-RETS. For systems smaller than 5 kW, 180 days for the first REC delivery will be allowed. The 15-year delivery term will begin in the month following the first REC delivery and will last 180 months.
2. Approved Vendors will be required to set up an irrevocable 15-year Standing Order for the transfer of RECs from the system to the utility.

    a. Community Solar projects which are not 100% subscribed will be allowed to set up a standing order for the percentage subscription the project has met. Community Solar projects shall update this percentage once per year based on their achieved subscription rates for the previous year.
    b. All other systems must set up an irrevocable standing order for 100% of the capacity the system produces.

3. Systems already energized at the time of contract signing, including systems energized on or after June 1, 2017, will be required to deliver their first REC within 90 days of contract signing, or 180 days for systems less than 5 kW. The 15-year delivery term will begin in the month following the first REC delivery and will last 180 months. Any RECs that were created prior to contract signing are not part of the contract and will not be transferred to the utility under the contract or purchased by the utility under the contract.

Submitting REC Information to Tracking Systems

Approved Vendors are responsible for entering system production in the tracking registry where the system is registered. This must be done at least annually (and as frequently as monthly) and as necessary to ensure that the delivery of required RECs under contract is complete prior to the annual report submission date. Detailed information about creating RECs in the PJM-GATS system can be found at https://www.pjm-eis.com/getting-started.aspx. Detailed information for M-RETS can be found at https://help.mrets.org

Credit Requirements and Delivery Obligations

Credit requirements and delivery obligations will be placed here in the final Program Guidebook. They are part of the contract development stakeholder process being coordinated by the Agency's Procurement Administrator. These topics are not open for stakeholder comment at this time.

Section 7: Annual Reports

Annual Report requirements

On an annual basis, each Approved Vendor will submit an Annual Report of the contracts and systems in its portfolio using the Approved Vendor portal at www.illinoisabp.com. The Annual Report will serve as the basis for verifying that RECs from projects are being delivered to the applicable utility, and, absent corrective actions taken by the Approved Vendor, can be a tool used to determine what actions may be taken by the utilities to enforce the contractual requirements that RECs are delivered, including, but not limited to, drawing on collateral. Additionally, the Annual Report will be used by the Agency to consider the ongoing eligibility of an Approved Vendor to continue participation in the program. For distributed generation systems, the report will include information on:

- RECs delivered by each of the systems in the portfolio
- Status of all systems that have been approved, but not yet energized, including any extensions requested and granted
- Energized systems that have not delivered RECs in the year
- Balance of collateral held by each utility
- A summary of requests for REC obligation suspensions, reductions, or eliminations due to force majeure events
- Information on consumer complaints received

For community solar projects, the report will also include:

- Percentage of each system subscribed on a capacity basis
- The number and type of subscribers (e.g., residential, small commercial, large commercial/industrial), including capacity allocated to each type
- Subscriber turn-over rates

The Agency will review the annual reports as well as utility-reported REC deliveries by contract to assess compliance with the requirements of the Adjustable Block Program and, if there are shortfalls of REC deliveries or subscription levels for photovoltaic community renewable generation projects, may coordinate with the applicable utility on what remedies should be taken, including drawing on collateral.

For community solar projects, the annual report will track subscription levels, subscriber mix, and small subscriber participation relative to the contract for that project. The Agency will review the reports and may coordinate with the applicable utility on which remedies should be taken, including drawing on collateral.

Further detail on the Agency's coordination with counterparty utilities is being addressed through the Agency's ABP REC delivery contract development process. Consistent with Section 6.7 of the Plan, "[t]he Agency, in consultation with its Program Administrator and/or its Procurement Administrator, will develop standard REC delivery contracts between the utilities and Approved Vendors much as its Procurement Administrator has done for the competitive procurement processes." This process will include "the opportunity for interested parties to comment on the contracts," and details about that comment process are forthcoming. Once the standard REC delivery contract finalized, this section of the Program Guidebook will be updated to reflect determinations made in the contract development process.

Approved Vendors will be given 90 days to cure any deficiencies found by the Agency and/or utilities. Failure to cure deficiencies may result in the contracting utility drawing on collateral. In addition, Approved Vendors' program eligibility may be jeopardized by failure to address and cure deficiencies.

Section 8: Guidebook Update Process

The guidebook will be periodically updated both as the program changes and as additional questions and issues arise. Minor updates to the guidebook will be made by the IPA in consultation with the Program Administrator on a regular basis. Such changes will be announced on the www.illinoisabp.com website; the version of the Guidebook published there will always be the latest version.

The Agency may also contemplate more significant changes to the guidebook that would benefit from stakeholder input. In these cases, a notice of the stakeholder process and a copy of the draft change will be published on the www.illinoisabp.com website. Stakeholders will be provided the opportunity to read the draft changes, attend a stakeholder meeting and/or webinar, and provide written comments on the proposed changes. Those comments will be reviewed by the Agency and its program Administrator prior to adopting more significant changes to the Program Guidebook.

Section 9: Glossary

Agency: The Illinois Power Agency (see 20 ILCS 3855)

Ameren Illinois: Ameren Illinois Company

Approved Vendor: An entity approved by the Program Administrator to submit project applications to the Adjustable Block Program and act as counterparty to the ABP contracts with the utilities.

Batch: The minimum size of a submission to the Adjustable Block Program, normally 100 kW with exceptions for the first submission of certain Approved Vendors.

Block: A defined size of program capacity with a defined level of incentives that declines at a rate of 4% per each new block as capacity is enrolled.

Category: A classification based on a system size and type. The program has three categories: Small Distributed Generation (DG) for DG systems 10 kW and below, Large Distributed Generation for DG systems above 10 kW up to 2 MW in size, and Community Solar for community solar projects regardless of size.

Co-located: A term related to community solar projects only, defined as:
-Two projects, of up to 2 MW each, on one parcel; or
-One project, of up to 2 MW, on each of two contiguous parcels.

ComEd: Commonwealth Edison Company

Community Solar: A solar project which (1) is interconnected to an electric utility, a municipal utility, or a rural electric cooperative, (2) allows subscribers to pay for shares or some other "interest" in the project, receiving bill credits in exchange; and (3) does not exceed 2,000 kW AC in size. Also known as a "photovoltaic community renewable generation project."

Distributed Generation: A system which is located on-site, behind a customer's meter, and used primarily to offset a single customer's load; it cannot exceed 2,000 kW AC in size.

Energized System: A system which is complete, has received a utility permission to operate, and has completed and received approval of Part II of the program application.

Group: One of the two Block Groups used to classify a system based on location. The Groups are:
Group A - Ameren Illinois, MidAmerican, Mt. Carmel, Rural Electric Cooperatives and Municipal Utilities located in MISO
Group B - ComEd, and Rural Electric Cooperatives and Municipal Utilities located in PJM

ICC: Illinois Commerce Commission (see 220 ILCS 5); The State Agency charged with regulating public utilities in Illinois, as well as approving aspects of the Adjustable Block Program.

IPA: Illinois Power Agency. The State Agency charged with administering the procurement of renewable energy resources to meet Illinois' renewable energy portfolio standard, in addition to procuring electric power supply for eligible retail customers of electric utilities and other responsibilities.

Interconnection Agreement: An agreement with the utility to interconnect the photovoltaic community solar or distributed generation system to the utility's distribution system.

Large DG: A distributed generation system larger than 10kW, up to 2MW

M-RETS: The Midwest Renewable Energy Tracking System. This is an independent entity from the State of Illinois, the IPA, and the Adjustable Block Program. It is one of two tracking registries, which along with PJM-GATS can be used to track creation, transfer, and retirement of RECs. More information can be found at the M-RETS website at https://www.mrets.org/

MidAmerican: MidAmerican Energy Company

Mt. Carmel: Mt. Carmel Public Utility

Net Metering: A provision in an electric utility's tariff that allows for crediting a customer's bill for all or some of the production of a distributed generation or community solar facility which has been exported to the distribution grid.

Non-ministerial Permit: A non-ministerial permits is a permit in which one or more officials consider various factors and exercise some discretion in deciding whether to issue (typically with conditions) or deny the permit.

Part I: The initial application into the program which contains detailed information on the system and its location. Part I approval results in an ICC approved contract with one of the distribution utilities. A system must be energized within 12 months (18 months for community solar projects) after this contract is approved.

Part II: The second part of the application completed after energization, demonstrating completion of the project in accordance with the Part I parameters approved.

PJM-GATS: The PJM Environmental Information Service generation attribute tracking system. This is an independent entity from the State of Illinois, the IPA, and the Adjustable Block Program. It is one of two tracking registries, which along with M-RETS can be used to track creation, transfer, and retirement of RECs. More information can be found at the PJM-GATS website at https://www.pjm-eis.com.

Program Administrator: The IPA's designee responsible for running day to day operations of the Adjustable Block Program. InClime has been designated the Program Administrator.

Project: A solar photovoltaic array and all associated equipment necessary for its generation of electricity and connection to the distribution grid. (Same as "system")

Qualified Person: A person who performs installations on behalf of the Distributed Generation Installer certificate holder (as certified by the ICC) and who has completed at least one of the following programs requiring lab or field work and received a certification of satisfactory completion: an apprenticeship as a journeyman electrician from a USDOL-registered or an applicable state-agency-registered electrical apprenticeship and training program; a North American Board of Certified Energy Practitioners (NABCEP) distributed generation technology certification program; an electrical training program for in-house employees established and administered by an electric utility regulated by the Commission; or an Associate in Applied Science degree from an Illinois Community College Board-approved community college program in solar generation technology."

Renewable Energy Credit: The environmental attributes represented by 1 MWh of electricity generated by a renewable generator.

Renewable Portfolio Standard: A law which requires a certain portion of the electricity served by investor owned utilities in a state comes from renewable generation.

Small DG: A distributed generation system less than or equal to 10 kW in size.

Small Subscriber: A residential or small commercial customer with a subscription below 25 kW. Eligible small commercial rate classes for the investor owned utilities are:
-Commonwealth Edison: "watt-hour delivery class" and "small load delivery class"
-Ameren Illinois: "DS-2"
-MidAmerican: "GE", "GD", "GET", "GDT", "GER", and "GDR"

Standard Test Conditions (STC): The solar irradiation of one kilowatt (kW) per square meter, a module temperature of 25 degrees Celsius, and an air mass 1.5.

Community Solar Subscription: An interest in a community renewable generation project expressed in kilowatts, which is sized primarily to offset part or all of the subscriber's electricity usage.

Community Solar Subscriber: A person who (i) takes delivery service from an electric utility, municipal utility, or rural electric cooperative, and (ii) has a subscription of no less than 200 watts to a community renewable generation project that is located in the utility's service area.

System: A solar photovoltaic array and all associated equipment necessary for its generation of electricity and connection to the distribution grid.