Appendix D - REC Pricing Model Description

Introduction

This Appendix D reflects the Agency's updated Renewable Energy Credit (REC) Pricing Model for the draft 2026 Long-Term Renewable Resource Procurement Plan (2026 Long-Term Plan). The latest REC Pricing Model updates and builds on its predecessor, the model that was adopted in the 2024 Long-Term Plan.[1] The model description below reflects: 1) updates made specifically for the 2026 Long-Term Plan, and 2) updates incorporated into the REC Pricing Model released in April 2025 that was used to determine REC prices for the 2025-26 program year. The REC Pricing Model can be found in Appendix E.[2]

The objective of the REC Pricing Model is to calculate the revenue and incentive levels required for a typical distributed solar or community solar project to meet its threshold investment requirements and the associated price in $/REC (the REC price).[3] The calculated REC price should be representative of a price that would be sufficient to allow a developer of a typical system to meet a project's expenses and debt service obligations, as well as the equity investors' minimum required after-tax rate of return.

There are two Programs administered by IPA, the Illinois Shines (formerly known as the Adjustable Block Program, or ABP) and Illinois Solar for All (ILSFA), each associated with four different Categories. There are two Block Groups, Group A and Group B. Group A corresponds to the service territories of Ameren Illinois, MidAmerican, Mt. Carmel Public Utility, and rural electric cooperatives and municipal utilities located in MISO; and, Group B corresponds to the service territories of ComEd and rural electric cooperatives and municipal utilities located in PJM. The REC Pricing Model was used to derive 16 sets of REC prices across both IPA administered Programs and across two Groups reflecting three key components: IPA Program, Program Category, and Group.

Illinois Shines is comprised of the following four Categories:[4]

- Distributed Generation (DG) – Small and Large
- Traditional Community Solar
- Community-driven Community Solar
- Public Schools

The ILSFA Program is comprised of the following four Categories:

- Low-Income DG Incentive (1–4 unit buildings)
- Low-Income DG Incentive (5+ unit buildings)
- Low-Income Community Solar
- Non-profit and Public Facilities

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[1] See 2024 REC Pricing Model (Appendix E): https://ipa.illinois.gov/energy-procurement/2024-ltrrpp-appendices.html

[2] See Appendix E at: https://ipa.illinois.gov/renewable-resources/long-term-plan/2026-appendices.html

[3] The model uses inputs from currently available information, including current utility rates and tariffs.

[4] Illinois Shines also includes a sixth category of program capacity; projects from Equity Eligible Contractors. At this time the IPA has elected to not create separate REC prices for this category.

For each program category and group combination, REC prices are developed for various capacity-based sub-categories, divided as following:

- up to 10 kilowatts (kW) alternating current (AC)[5]
- greater than 10 to 25 kW AC[6]
- up to 25 kW AC[7]
- greater than 25 to 100 kW AC
- greater than 100 to 200 kW AC
- greater than 200 to 500 kW AC
- greater than 500 to 2,000 kW AC
- greater than 2,000 to 5,000 kW AC

The remainder of this Appendix is structured as follows:

- The **Methodology Overview** section describes the core calculation framework, including the key equation used to determine REC prices and the approach for calculating size-based bin adjustments.
- The **CREST Model** section explains the role of the National Renewable Energy Laboratory's model in developing cost-of-energy estimates and the Illinois-specific modifications applied.
- The **Capital Expenditures** section details the cost inputs, data sources, and scaling methodologies used to produce system cost estimates across program categories and system sizes.
- The **Net Metering Credits** section describes the assumptions, tariffs, and escalation methods used to estimate revenue offsets from net metering.
- The **REC Production** section describes the process for converting system capacity to expected annual generation, applying capacity factors, and calculating total REC output.
- Finally, the **Other Updates** and **Proposed REC Prices for the Draft 2026 Long-Term Plan** sections summarize additional modeling refinements and program-specific adjustments that influence the final proposed REC prices.

Methodology Overview

The calculation of REC prices is anchored in a cost-of-service approach that identifies the incentive level necessary to make representative projects economically viable. The fundamental equation is:

[5] Available for DG only

[6] Available for DG only

[7] Available for categories other than DG

$$Base\ REC\ Prices\ (\$/REC) = \frac{25\ year\ PV\ COE\ for\ 5{,}000\ kW\ (\$) - Portion\ of\ 25\ year\ PV\ Net\ Metering\ Credits\ (\$)}{REC\ production\ over\ N\ years\ (MWh)}$$

Where:

- 25-year PV COE = the present-value (PV) cost of energy (COE) for a 5,000-kW project over a 25-year life.
- 25-year PV Net Metering Credits = the PV revenues from net metering over a 25-year life.
- N =15 for DG projects and 20 for community solar projects.
- One REC is equal to one megawatt-hour (MWh) of electricity generated. Therefore $/REC is equivalent to $/MWh.

The base REC price is derived from the most cost-efficient system size (5,000 kW AC) because this size allows for economies of scale in construction, operation, and financing. The PV COE for the base system reflects the total costs required to develop, finance, and operate the project over a 25-year life. The calculation of COE has embedded incentives such as the federal tax credits and the Smart Inverter rebate. Next, the present value of net metering revenues is subtracted from the PV COE to determine the revenue shortfall. Notably, only a portion of net meeting revenues are subtracted from COE. Finally, the revenue shortfall is then divided by the system's expected REC output to yield the base REC price.

Once the base REC price is established, adjustments are made for different project size bins to reflect variations in costs and revenues. These adjustments are calculated using a midpoint approach between the revenue shortfall of the two system sizes that form the upper and lower limits of each bin. Under this framework, the REC price adjustment for the 2,000-5,000 kW bin is zero. The REC price adjustment for the 500-2,000 kW bin reflects the average of revenues shortfall per REC between a 500 kW project and a 2,000 kW project. This method ensures that smaller systems, which often have higher per-unit costs and potentially different revenue streams, receive higher REC prices to maintain economic feasibility, while larger systems may have smaller adjustments due to scale efficiencies.

CREST Model

The REC Pricing Model uses a modified version of National Renewable Energy Laboratory's (NREL) publicly available Cost of Renewable Energy Spreadsheet Tool (CREST)[8] to calculate the revenue shortfall, which is a main component in the REC pricing calculation. The CREST model was developed by NREL to aid policymakers, regulators and renewable energy developers with estimating renewable energy costs for various public policy purposes, such as establishing cost-based or performance-based incentives.

As described in the User Manual published with the CREST model, CREST at its core is an economic cash flow model designed to assess project economics, design cost-based incentives, and evaluate

[8] The CREST model is available on NREL's website: https://financere.nrel.gov/finance/content/crest-cost-energy-models.

the impact of various state and federal support structures.[9] CREST calculates the COE needed for a project to meet all expenses, debt obligations (if applicable), and investor return requirements.

In its default configuration, CREST includes inputs for capital expenditures (modules, inverters, balance of system, development costs, and interconnection), operating and maintenance (O&M) expenses, financing terms, incentive values, and tariff structures. For the purposes of this Plan, the CREST model has been modified to incorporate updated Illinois-specific market conditions, including labor cost premiums, inflation adjustments, and historical capacity factors. The model has also been adapted to accommodate updated scaling factors for different system sizes, ensuring that the outputs reflect realistic costs and revenues across all pricing bins.

Capital Expenditures

For the current update to the REC Pricing Model, the Agency uses resource costs derived from the NREL Q1 2023 Benchmark Cost Report.[10] The report publishes installation cost estimates for the following categories:

- Module
- Inverter
- Structural Balance of System (BoS) components
- Electrical BoS components
- Fieldwork
- Office Work Without Interconnection
- Other (system capital costs not included elsewhere, commonly including management salaries and other financial costs)

The Q1 2023 edition provided data for two resource types: a Residential Solar Project, assumed to be 10 kW AC, and a Commercial/Community Solar Project, assumed to be 2,000 kW AC. These NREL data form one portion of the raw inputs to the REC Pricing Model.

A second portion of the raw inputs reflects global market dynamics, including geographically specific construction wages, inflation rates, the proportion of costs attributable to equipment, and tariff impacts on equipment costs. A summary of the cost components and their associated key statistics can be found in Table D-1 and Table D-2 below.

[9] Gifford, Jason S. & Grace, Robert C. "CREST Cost of Renewable Energy Spreadsheet Tool: A Model for Developing Cost-Based Incentives in the United States." User Manual Version 4. July 2013. https://www.nrel.gov/docs/fy13osti/50374.pdf .

[10] Data can be found https://data.nrel.gov/submissions/221

Table D-1: Capital Costs by Component for Residential Projects ($/W dc) Raw Inputs

Cost Component	Unit	Residential	Commercial/ Community
NREL Q1 2023 Benchmark Cost Report			
Module	$ / W dc	0.34	0.37
Inverter	$ / W dc	0.31	0.05
Structural BoS	$ / W dc	0.24	0.15
Electrical BoS	$ / W dc	0.33	0.21
Fieldwork	$ / W dc	0.18	0.26
Officework without interconnection	$ / W dc	0.47	0.15
Other	$ / W dc	0.59	0.50
Cost reduction between 2022 and 2026 in nominal $	% of 2022 costs	100%	92%
Global inputs			
Median construction labor wages in IL relative to nation-wide median	%	132%	
Construction labor in Group B relative to Group A	%	130%	
Inflation between 2022-2026	%	112%	
% Of BoS Cost as Equipment	%	76%	58%
% of BoS and Module cost increase due to tariff	%	70%	

Beginning with the NREL dataset, Balance of Plant costs for the Fieldwork Labor component are increased by 32% to reflect the labor premium in Illinois relative to the nationwide median. This adjustment was the only modification to Fieldwork Labor for Group A projects. For Group B projects, an additional 30% increase is applied to reflect the higher labor premium in the Group B service territories relative to Group A.

Interconnection costs for systems up to 25 kW are set at $200 per Section 16-107.5(h-5)(3) of the Public Utilities Act. For community solar projects interconnections costs were based on actual project data that have been Part II verified by the IL Shines Program Administrator prior to the 2024 Long-Term Plan.

All costs were then converted from 2022 dollars to 2026 dollars, incorporating both observed cost reductions since 2022 (based on survey results) and inflation adjustments. The resulting costs were also adjusted to reflect tariff increases for Generation and Balance of Plant costs. This adjustment reflects the estimated proportion of imported components subject to tariffs and a weighted average of tariff rates from various source countries.

For Commercial/Community Solar, additional calculations were performed to produce results for systems smaller or larger than 2,000 kW. The scaling factors used for this purpose were originally developed for the August 2022 REC Pricing Model, which had a 500 kW system from the NREL dataset as the representative Commercial/Community Solar system. At that time, the scaling methodology was designed to translate costs from the 500 kW base case to other system sizes by accounting for cost efficiencies and diseconomies at different scales. For the current update, these scaling factors were adjusted to align with the 2,000 kW base case from the Q1 2023 NREL report, ensuring that the relative size-based cost relationships remain consistent with the updated base system. The adjusted scaling factors were then applied to produce final outputs for Commercial/Community Solar systems across a range of capacities.

Table D-2: Capital Costs by Component for Commercial & Utility-scale Projects ($/W dc)

Group A

		Residential	Commercial/Community					
AC System Size	**Unit**	**10**	**25**	**100**	**200**	**500**	**2000**	**5000**
Generation Equipment	$/kW dc	1,236	776	776	751	738	732	599
Balance of Plant	$/kW dc	1,081	804	804	704	652	630	631
Balance of Plant (Prevailing Wage Labor 32% increase for Commercial/Community)	$/kW dc	1,163	934	934	808	741	714	716
Interconnection	$/kW dc	158	128	128	100	83	78	66
Development Costs and Fee	$/kW dc	1,182	776	776	709	672	658	546
Total	$/kW dc	3,657	2,613	2,613	2,367	2,235	2,182	1,927

Group B

		Residential	Commercial/Community					
AC System Size	**Unit**	**10**	**25**	**100**	**200**	**500**	**2000**	**5000**
Generation Equipment	$/kW dc	1,236	776	776	751	738	732	599
Balance of Plant	$/kW dc	1,158	905	905	792	733	708	709
Balance of Plant (Prevailing Wage Labor 32% increase for Commercial/Community)	$/kW dc	1,265	1,070	1,070	925	849	817	820
Interconnection	$/kW dc	158	128	128	100	83	78	66
Development Costs and Fee	$/kW dc	1,182	776	776	709	672	658	546
Total	$/kW dc	3,734	2,749	2,749	2,485	2,343	2,286	2,031

Net Metering Credits

Net metering credits represent the primary source of operating revenue for DG (residential and small commercial) and community solar projects and therefore must be subtracted from the present-value cost of energy (PV COE) when calculating REC prices. To estimate future net metering credits, historical residential and commercial retail rates were compiled and projected forward by applying an annual escalation rate of 3%.

For residential retail rates, the modeled credits include the following components:

- Energy charges
- Transmission charges
- Distribution facility charges
- Energy transition assistance charges
- Energy efficiency adjustment
- Zero emission adjustment
- Renewable energy adjustment
- Carbon-free resource adjustment
- Environmental cost recovery adjustment

For commercial retail rates, the modeled credits include the following components:

- Energy charges
- Transmission charges
- Capacity charges
- Energy transition assistance charges
- Energy efficiency adjustment

- Zero emission adjustment
- Renewable energy adjustment
- Carbon-free resource adjustment
- Environmental cost recovery adjustment

Energy charges for each utility were calculated by averaging the annual day-ahead marginal energy prices over the most recent five calendar years. Capacity charges were calculated using five years of historical values, converted into $/kWh using Peak Load Contribution (PLC) and customer usage data. For Group A (Ameren), a single annual capacity charge in $/PLC-Day is multiplied by the estimated PLC and 365 days, then divided by the average annual commercial customer usage from the Energy Information Administration (EIA) Form 861. For Group B (ComEd), the weighted average capacity charge in $/kW-Month is calculated using four months of summer charges and eight months of winter charges, multiplied by the PLC and 12 months, then divided by annual commercial customer usage from the EIA dataset.

All remaining retail rate components, such as transmission charges, energy transition assistance, renewable energy adjustments, and environmental cost recovery adjustments, are taken directly from utility tariffs for the applicable customer classes.

Under the Climate and Energy Jobs Act (CEJA), residential solar net metering rules have been updated such that on-site self-consumption of solar generation continues to be credited at full retail value, while any exported generation is compensated only at the energy supply rate, which excludes distribution charges. To better align incentives with energy usage efficiency, the Agency assumes a 70% self-consumption and 30% export profile for residential systems when modeling net metering revenues.

As noted earlier in the methodology, only a portion of the total net metering credit value is counted toward project revenues in the REC pricing model. The full array of Net Metering value allocated (revenues) and participant savings percentages by program and category are provided in Table D-3 below.

Table D-3: Net Metering Value Allocation & Subscriber/Participant Savings

Program	Program Category	% of Net Metering Value Allocated	Subscriber/ Participant Savings
Adjustable Block Program	DG	80%	20%
	Community Solar	80%	20%
	Community-driven Solar	80%	20%
	Public Schools	80%	20%
IL Solar for All	DG (1-4 Units)	0%	100%
	DG (5+ Units)	50%	50%
	Low-Income Community Solar	50%	50%
	Non-profit and Public Facility	50%	50%

REC Production

For each program, annual REC production is calculated by first converting the system's alternating current (AC) capacity, measured in kW, to its direct current (DC) capacity using the applicable AC-to-DC conversion factor. The DC capacity is then converted into annual generation, expressed in kWh, by applying the corresponding DC-based capacity factor. Capacity factors are updated using the average performance observed in most recently verified project data. Both AC-to-DC conversion factors and capacity factors vary by program category and system size. The specific AC-to-DC conversion factors and capacity factors for DG are provided in the Table D-4 below.

Table D - 4: AC-DC Conversion Factors and Capacity Factors

Group A – Ameren								
Generator Nameplate Capacity	kW ac	10	25	100	200	500	2000	5000
AC-DC Conversion Factor	%	82%	83%	84%	83%	82%	80%	78%
Capacity Factor	% dc	15%	15%	15%	15%	15%	15%	15%

Group B – ComEd								
Generator Nameplate Capacity	kW ac	10	25	100	200	500	2000	5000
AC-DC Conversion Factor	%	83%	84%	81%	81%	81%	78%	78%
Capacity Factor	% dc	13%	13%	14%	14%	14%	15%	15%

Other Updates

The latest REC Pricing Model for the 2026 Long-Term Plan reflects additional updates as described below:

- The ITC utilization factor has been adjusted downward from 100% to 95%. This adjustment acknowledges that certain project expenses, such as land lease and customer acquisition costs, do not qualify for ITC benefits.
- As a result of the recent reconciliation legislation, bonus depreciation for solar projects has been restored to 100%, up from 40%.
- The recent reconciliation legislation substantially alters availability of the federal Investment Tax Credit (ITC) for solar projects.
    - For residential, customer-owned systems, the 30% ITC will expire on December 31, 2025. For commercial and third-party owned projects under Section 48E, the bill imposes accelerated qualification requirements: projects must begin construction within 12 months of enactment and be placed in service by December 31, 2027, to retain full ITC eligibility. Additionally, projects must comply with Foreign Entity of Concern (FEOC) restrictions, demonstrating that a project did not receive "material assistance" from a "prohibited foreign entity" during construction, or that a "foreign-influenced entity" is not proposing to claim or sell tax credits.
    - The Agency assumed the inclusion of the ITC as a funding stream within the REC Pricing Model for the 2026-27 Program Year to reflect the scenario where many (potentially most) Small DG projects may have access to the ITC and helps achieve the Agency's goals to incentivize projects that maximize the use of incentives and extend the available RPS budget as far as possible. Again, while it may be true that some projects seeking to participate in the Illinois Shines program may not have access to the ITC, it is the Agency's understanding that many third-party owned projects very well might – at least through some portion of the 2026-27 Program Year.
    - The Agency has chosen to model REC prices with the simplified assumption that participating projects will have access to the ITC and thus the resulting REC prices reflect that expectation.[11]
- Additional updates were made to improve model usability and flexibility. For example, the "Size-specific Assumptions," "Group-specific Assumptions," and "Program-specific Assumptions" tabs have been consolidated into a single "Inputs Assumptions" tab, where all inputs can vary by program and system size. A macro has been created to output REC prices for all programs except for public schools simultaneously.

Proposed REC Prices for the Draft 2026 Long-Term Plan

As described above, capital costs, net metering rates, the percentage of net metering credits allocated to developers, and capacity factors all contribute to variation in REC prices by group,

[11] See the 2026 Long-Term Plan Section 7.5 and Section 8.5 which provides greater information on the analysis completed and the determinations made for both IL Shines and Illinois Solar for All REC Prices.

category, and system size. In addition to these drivers, several other factors influence REC pricing across different programs:

- Community solar projects receive a pricing bin adjustment calculated in the same manner as for DG. For projects with 50% or more small subscribers, this adjustment is set at $14.82/REC. The small subscriber adder is applied equally across all project sizes within the Traditional Community Solar and Community-Driven Community Solar categories.
- The assumed percentage of debt financing varies by program and category. For example, Illinois Shines programs typically assume 55% debt, while the ILSFA program assumes 0% debt.
- REC contract lengths differ by program. DG and community solar projects follow a 15-year contract term, while public school projects are modeled with a 20-year term.
- Certain categories, such as ILSFA non-profits and public facilities, assume that the project owner is not a taxable entity, which impacts the valuation of federal tax incentives.
- REC prices for Illinois Shines Public Schools are not modeled independently using CREST. Instead, they are based on Illinois Shines DG CREST model results. Using the Illinois Shines DG REC prices, along with the applicable discount rates, AC-to-DC conversion ratios, and capacity factors, the Agency calculated the net present value (NPV) of revenues over the contracted spend period (6.5 years). Since Illinois Shines Public School RECs are paid on an as-delivered basis over 20 years, the REC price was increased to match the NPV of Illinois Shines DG projects under this longer payment schedule. This adjustment was determined by testing various percentage increases to Illinois Shines DG REC prices to identify the revenue requirement needed for equivalence. In addition, an extra $5/REC is added to further incentivize public school solar development.

With all updates described above, the model outputted REC prices for all programs. The Agency then made additional adjustments given historical and current program participation levels.

- ***<u>Small Distributed Generation Pricing</u>***: The modeling results show a small increase in the REC prices for 2026-27. This category has historically seen over-subscriptions and resulting waitlists. Most recently, during the 2024-25 Program Year the category's capacity closed May 6, 2025. As discussed above, the Agency expects projects to utilize the ITC in the 2026-27 Program Year. Therefore, the Agency believes it is appropriate to utilize the modeled results for the proposed 2026-27 REC prices for this category.

- ***<u>Large Distributed Generation Pricing</u>***: The modeling results showed a substantial decrease in REC prices, ranging from -10% to nearly -35% for this category. These modeled results are primarily reflective of two key drivers: (1) updated retail rate escalation resulting from a substantial increase in capacity prices, and (2) the reinstatement of 100% bonus depreciation. When evaluating historic project participation, this category has seen moderate to substantial under-subscription. Given historically low market participation, the Agency finds lowering REC prices could undermine category progress and potentially further stifle project development, and as such, proposes to instead maintain REC prices at the 2025–26 published levels.

- ***Traditional Community Solar Pricing***: Based upon the prevailing market-based inputs, the modeling results for this category have resulted in a deviation between Group A and Group B prices. Modeled Group A prices slightly increased as compared to 2025-26 prices, while modeled Group B prices fell substantially. There are two elements at play causing the differences between Groups and causing the Group B price decline: (1) the Agency implemented a 10% price cap to the modeled REC prices for the 2025-26 Program year, and (2) capacity prices for PJM were updated, reflecting the significant increase in the value. As discussed above, the effect of capacity prices increasing is a resulting decline in REC prices (driven by higher capacity-related revenues). This is seen in Group B and the resulting decline in prices.
    - When developing the 2025-26 REC prices, the Agency applied the 10% REC price change cap in any instance where a modeled price would have resulted in a year-over-year change of +/- 10%. This cap impacted multiple modeled REC prices. When completing the 2026-27 REC price modeling and comparing the resulting prices to 2025-26 REC prices, the Agency found that some changes were significant (in some instances a change in excess of 25%). Upon further analysis, one causal factor was the implementation of the 10% REC price cap for the 2025-26 REC prices – with modeled 2026-27 REC prices attempting to 'catch up' for the limit placed in the prior period. Retrospectively, if REC prices during the 2025-26 Program Year had not been affected by the 10% cap, the subsequent change in the modeled 2026-27 Program Year REC prices would have been more moderate.
    - An additional factor considered by the Agency is the application submission levels for this category. Overall, the Traditional Community Solar category has been over-subscribed, with a substantial waitlist each year.
    - Based upon the set of facts for this category – substantially high participation levels, imbalanced 2025-26 REC pricing as a result of the 10% cap, and the impact of the 2026-27 modeled REC prices, the Agency proposes to hold prices constant for Group A (i.e., maintain the 2025-26 REC Prices), thereby not increasing the REC prices as modeled which would likely result in higher payouts to participating projects in an already over-subscribed category. Further, the Agency proposes implementing the model results for Group B which would bring this category back in balance with market prices and appropriately reflects sub-category over-subscription.

- ***Community Driven Community Solar Pricing***: REC price modeling for this category resulted in moderate price increases for both Group A and B, primarily driven by higher cost factors. An important consideration in the Agency's determination of what REC prices to implement are subscription levels, which have roughly matched the target for this sub-category for both Group A and Group B. As such, the Agency determined that it is appropriate to utilize the modeled REC prices for 2026-27, which appropriately capture the costs for this sub-category and attempt to maintain the momentum into the 2026 Long-Term Plan.

- ***Public Schools***: Prior to modeling REC prices, the Agency first recognized that this category has been significantly under-subscribed; however, REC prices may not be the only driver causing the challenges in uptake. With this in mind, the Agency modeled prices for projects in the Public Schools category that derived a decrease as compared to 2025-26 REC prices. Decreases varied by project size, ranging from -11% to over -34%. Similar to preceding categories, the prevailing driver for the decrease in REC price was a combination of the impact of 100% bonus depreciation and the substantial increase in capacity prices. As highlighted previously, the Public Schools category has substantially lagged the targeted capacity available, resulting in persistent under-subscription. While market factors indicate that REC prices for public school categories should decrease, the Agency finds that this would only exacerbate an already challenged sub-category. As such, the Agency has proposed to maintain the REC prices currently in effect (i.e., those for the 2025–26 Program Year) through 2026-27 Program Year.

- ***ILSFA Residential Solar (Large)***: Modeled REC Prices furcate small to moderate price increases as compared to 2025-26, with smaller projects (0-25 kW) seeing an ~11% to 20% increase and larger projects (25-5,000 kW) seeing a slight decline of ~2% to an increase of ~6%. However, unlike the Residential Solar (Small) sub-program, the Residential Solar (Large) sub-program has been perpetually under-subscribed. Given the low participation rate, the Agency proposes to utilize the modeled pricing, increasing REC prices for most size categories for this sub-program in an effort to support project development for the 2026-27 Program Year.

The proposed REC prices for the 2026 Long-Term Plan – Illinois Shines and Illinois Solar for All – can be found Table D-5 below.

Table D - 5: Illinois Shines and ILSFA REC Prices *(Assumes ITC availability for all categories)*

	Group A_Adjustable Block Program_Distributed Generation	Group B_Adjustable Block Program_Distributed Generation
0 - 10 kW	$69.22	$77.49
>10 - 25 kW	$60.51	$69.26
>25 - 100 kW	$59.53	$69.65
>100 - 200 kW	$55.63	$65.09
>200 - 500 kW	$45.64	$53.40
>500 - 2000 kW	$42.37	$49.57
>2000- 5000 kW	$31.96	$37.39

	Group A_Adjustable Block Program_Community Solar	Group B_Adjustable Block Program_Community Solar
0 - 25 kW	$57.49	$73.70
>25 - 100 kW	$58.84	$68.72
>100 - 200 kW	$57.50	$60.45
>200 - 500 kW	$53.46	$54.10
>500 - 2000 kW	$46.02	$43.99
>2000- 5000 kW	$33.99	$30.22

	Group A_Adjustable Block Program_Community-driven Solar	Group B_Adjustable Block Program_Community-driven Solar
0 - 25 kW	$80.66	$96.74
>25 - 100 kW	$81.88	$97.27
>100 - 200 kW	$78.09	$93.45
>200 - 500 kW	$68.02	$85.02
>500 - 2000 kW	$58.77	$71.34
>2000- 5000 kW	$46.38	$52.95

	Group A_Adjustable Block Program_Public Schools	Group B_Adjustable Block Program_Public Schools
0 - 25 kW	$77.17	$93.17
>25 - 100 kW	$68.57	$84.96
>100 - 200 kW	$65.81	$76.91
>200 - 500 kW	$57.72	$66.88
>500 - 2000 kW	$54.51	$61.04
>2000- 5000 kW	$42.15	$46.74

	Group A_IL Solar for All_Distributed Generation (1-4 Unit)	Group B_IL Solar for All_Distributed Generation (1-4 Unit)
0 - 10 kW	$194.82	$185.02
>10 - 25 kW	$164.39	$163.75
>25 - 100 kW	$132.30	$137.93
>100 - 200 kW	$129.00	$129.24
>200 - 500 kW	$120.41	$119.30
>500 - 2000 kW	$116.65	$113.64
>2000- 5000 kW	$101.37	$97.45

	Group A_IL Solar for All_Distributed Generation (5+ Units)	Group B_IL Solar for All_Distributed Generation (5+ Units)
0 - 10 kW	$130.92	$145.79
>10 - 25 kW	$106.21	$119.82
>25 - 100 kW	$83.10	$92.31
>100 - 200 kW	$79.47	$85.84
>200 - 500 kW	$70.90	$76.73
>500 - 2000 kW	$67.86	$71.41
>2000- 5000 kW	$54.22	$58.07

	Group A_IL Solar for All_Low-Income Community Solar	Group B_IL Solar for All_Low-Income Community Solar
0 - 25 kW	$109.91	$122.97
25 - 100 kW	$111.35	$124.31
100 - 200 kW	$107.74	$121.24
200 - 500 kW	$97.55	$112.62
500 - 2000 kW	$87.75	$97.96
2000- 5000 kW	$72.98	$77.38

	Group A_IL Solar for All_Non-profit & Public Facility	Group B_IL Solar for All_Non-profit & Public Facility
0 - 25 kW	$114.61	$131.59
25 - 100 kW	$116.05	$128.36
100 - 200 kW	$110.85	$119.14
200 - 500 kW	$99.96	$107.97
500 - 2000 kW	$96.29	$101.18
2000- 5000 kW	$78.62	$83.83