# Appendix D - REC Pricing Model Description

## REC Pricing Approach

## August 22, 2022

For this 2022 Long-Term Renewable Resources Procurement Plan ("2022 Long-Term Plan"), this Appendix has been updated from the version included with the Initial Long-Term Renewable Resources Procurement Plan ("Initial Plan" or "Initial LTRRPP") that was finalized in 2018.[1] This Appendix reflects updates made to the REC Pricing Model following the Illinois Commerce Commission ("ICC") Final Order filed July 14, 2022 in Docket 22-0231. The first Revised Long-Term Renewable Resources Procurement Plan that was finalized in 2020 did not include an update to the REC Pricing Model.

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").[2] 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.

The calculated REC price is net of (i) a portion of revenues received through net metering, (ii) any assumed incentives such as federal tax credits, and (iii) the Distributed Generation Rebate[3] value ("Smart Inverter Rebate"), if applicable.

Under Section 16-107.5(j) of the Public Utilities Act ("PUA"), net metering is a credit for energy,[4] transmission, and distribution charges for the net generation produced by distributed generation projects. For systems that receive a Smart Inverter Rebate, the net metering credit does not include distribution charge credits, pursuant to Section 16-107.6(c)(3) of the PUA. For community solar, the net metering distribution rate is not included. Based on feedback on the draft 2022 Long-Term Plan from Public Act 102-0662, the net metering credit has been expanded for this 2022 Long-Term Plan to include the following: energy efficiency adjustments, energy transition assistance charges, environmental cost recovery adjustments, renewable energy adjustments, and zero emission adjustments. Systems 25 kW and larger also assumed to have capacity charges included in their energy rate. Starting in 2025, net metering for all new installations, including distributed generation, will be for energy only and that will be reflected in any future updated of this REC Pricing model.

As further described in the section on the REC price calculation, the REC Pricing Model is set up using the following capacity-based bins for block pricing:

[1] See: https://ipa.illinois.gov/content/dam/soi/en/web/ipa/documents/2018procurementplan/appendixd-june-4-2018.pdf

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

[3] See, generally, 220 ILCS 5/16-107.6.

[4] For residential customers, the utility's energy supply charge generally includes capacity charges billed by the relevant Regional Transmission Organization ("RTO").

For Small Distributed Generation projects:

- up to 10 kilowatts ("kW") alternating current ("AC")

For Large Distributed Generation and Community Solar projects:

- up to 25 kW AC
- 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 kW to 5,000 kW AC

The bins were chosen based on the available pricing data points as described in the section on installation cost data and stakeholder input received on the Initial Plan. A base price is calculated for the most economic system size (greater than 2,000 to 5,000 kW[5]), and the prices for the other bins are determined through the use of adjustments, as further described in the section on the REC pricing calculation. The adjustments were determined using a midpoint approach and using the same model that was run for the base price, as further described in the section on distributed generation REC model adjustments. Community-driven and Traditional Community Solar projects face additional costs and less revenue than distributed generation systems. On the revenue side, they are eligible only for energy-only net metering,[6] while on the cost side, there may be the cost of acquiring, maintaining, and managing subscribers. The price for community solar reflects a baseline for those additional costs and lower revenue.

The REC Pricing model was used to determine 16 sets of REC prices reflecting three key components: Program, Category, and Group. There are two Programs administered by IPA, the Adjustable Block Program ("ABP") and Illinois Solar for All ("ILSFA"), each associated with four different Categories. There are two Block Groups, Group A and Group B, which correspond to the Ameren Illinois and ComEd service territories, respectively. The ABP offers the following four Categories:[7]

- Distributed Generation
- Community Solar (Traditional, or Community-Driven)
- Community-driven Solar
- Public Schools[8]

The ILSFA Program offers the following four Categories:

[5] This 2022 Long-Term Plan is the first to include REC pricing for systems larger than 2,000 kW AC up to 5,000 kW AC.

[6] 220 ILCS 5/16-107.5(*l*)(2).

7 ABP also includes a program category for projects from Equity Eligible Contractors. For the 2022 Long-Term Plan the Agency is not proposing a separate set of REC prices for those projects.

[8] Public Schools REC prices are not derived from a separate model run, rather a post-model run calculation based on the modeled ABP Distributed Generation REC prices.

- Low-Income Single-Family and Small Multifamily Solar Incentive (1-4 unit buildings)
- Low-Income Large Multifamily Solar Incentive (5+ unit buildings)
- Low-Income Community Solar
- Non-profit and Public Facilities

This Appendix D reflects the Agency's updated REC Pricing Model for the 2022 Long-Term Plan. It updates and builds on the model that was adopted in the Initial LTRRPP's docketed proceeding and adopted by the Final Order approving that Plan.[9] It also reflects updates incorporated into the REC Pricing Model that was released in August 2021 as part of the now withdrawn draft Second Revised Long-Term Plan which included input from stakeholders gathered in June and July of 2021.[10] Further refinements have been made in response to stakeholder feedback and suggestions in response to the January 2022 draft 2022 Long-Term Plan.

The spreadsheet that implements the modeling described in this Appendix can be found in Appendix E.[11] Please note that Appendix E was previously multiple spreadsheets to reflect various blocks and categories. For this 2022 Long-Term Plan, Appendix E has been updated to be a single Excel spreadsheet with consolidated assumptions, and the ability to use drop-down options to model and display the various combinations of blocks and categories.[12]

## Model Selection and Description

The REC Pricing Model uses a modified version of National Renewable Energy Laboratory's ("NREL") publicly available Cost of Renewable Energy Spreadsheet Tool ("CREST").[13] CREST is widely known and respected in the renewable energy industry. For the purpose of setting REC prices for the ABP and ILSFA, modifications (as described in the following sections) to the model inputs and format of the outputs were made so as to refine the results for use in determining REC prices.[14]

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. The model calculates the total incentive necessary for a renewable project to cover its costs and achieve a necessary economic return to the project owner.

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[9] Appendices D and E from the Initial Plan can be found at: https://ipa.illinois.gov/energy-procurement/2018-long-term-renewable-appendices.html

[10] See: Appendices D and E at: https://www2.illinois.gov/sites/ipa/Pages/Second-Revised-LTRRPP-Appendices.aspx

[11] See: https://ipa.illinois.gov/energy-procurement/2022-ltrrpp-appendices.html

[12] The spreadsheet model must be opened as a macro-enabled file and users should take care not to alter the layout of any sheets within, otherwise the references in the visual basic code may become incorrect and the model will not function as intended.

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

[14] As described in the previous section, the CREST model output is not the final REC price, as revenues received from net metering must be netted out from the present-value Cost of Energy ("COE").

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 (e.g., feed-in tariffs ("FITs")), and evaluate the impact of various state and federal support structures.[15] CREST is a suite of four analytic tools, one each for solar (photovoltaic and solar thermal), wind, geothermal, and anaerobic digestion technologies.

The CREST User Manual provides a summary of the primary and secondary model outputs:[16]

> *The primary output is the modeled project's COE. The COE is the year-one price in cents per kilowatt hour (¢/kWh) necessary for the project to meet all expenses and debt service obligations (if applicable), as well as the equity investors' minimum required after-tax rate of return. At the model user's discretion, the COE can be calculated to assume an escalation rate (applied to all or a portion of the initial rate) over time. In calculating the COE, the CREST model includes the option to specify both a percentage of the tariff subject to escalation and the associated tariff escalation rate. The results can be used to inform a range of cost-based incentives, including FIT rates.*
>
> *The secondary output is the modeled project's levelized cost of energy (LCOE)[17]. The LCOE is a single, fixed, non-escalating value over the incentive's payment duration. The escalating stream of payments generated by the COE and the constant stream of payments generated by the LCOE have the same Net Present Value (NPV) when discounted at the same required rate of equity return. Policymakers can refer to the LCOE output if policy objectives favor a single, fixed price per kWh for the life of the cost-based tariff. If the tariff rate escalation factor is set to zero, then the calculated COE and LCOE values will be equal.*

CREST provides the interface for the input assumptions necessary for the calculation of a REC price for a solar photovoltaic project including, but not limited to (i) capital costs (module and inverter costs, balance of plant costs, interconnection costs, development costs and fees, reserves and financing costs), (ii) operations and maintenance costs, (iii) cost-based tariff rate structure, and (iv) federal and state incentives / rebates / tax credits, etc. The REC Pricing Model uses input assumptions modified from the default CREST values that are based on more current and granular installation cost data, input from stakeholder responses to both the Request for Comments[18] and the draft Initial LTRRPP, and conclusions drawn from intervenor comments in ICC Docket No. 17-0838, as well updated data gathered for the draft Second Revised Plan and this 2022 Long-Term Plan as described below.

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[15] 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://financere.nrel.gov/finance/files/crest_user_manual_v-4.pdf.

[16] Ibid, pages 3-4.

[17] The "levelized cost-of-energy" is presented either as a constant price in each year (nominal levelized) or as a constant price adjusted for inflation (real levelized). Real LCOE is often used for comparative studies, whereas the nominal LCOE is typically used in setting, describing, or establishing actual prices. The CREST model calculates a nominal LCOE.

[18] The Request for Comments were sent out following the Agency's May 17, 2017 and May 18, 2017 workshops held in Chicago to discuss the Renewable Portfolio Standard, Adjustable Block Program, Community Renewable Generation Program, and Illinois Solar for All Program. The Request for Comments was sent out to stakeholders on June 6, 2017. Stakeholder responses were received by June 27, 2017. Subsequent Requests for Comments were issued (and comments received) in July, 2021 in preparation for the now withdrawn Second Revised Long-Term Plan, and again in November, 2021 in preparation for this 2022 Long-Term Plan.

## CREST Model Modifications

As noted before, the REC Pricing Model adapts and modifies the NREL CREST model for the purposes of calculating REC prices for this Plan. The CREST model is an economic cash flow model that estimates the cost of energy associated with specific input assumptions regarding technology type, location, system capital and operating costs, expected production, project useful life, the duration of the cost-based tariff, and various project financing variables. The distributed generation model was run with modifications made to certain input assumptions to reflect current publicly available data and input from stakeholder comments in response to the draft and final Initial and Second Revised Plans, and the draft 2022 Long-Term Plan. The REC Pricing Model Excel spreadsheet modeling tool for the 2022 Long-Term Plan is available at: https://ipa.illinois.gov/energy-procurement/2022-ltrrpp-appendices.html. As noted earlier, the approach for REC pricing is based on calculating a base price for the most economic block size (previously 500 to 2,000 kW AC, now 2,000 kW to 5,000 kW AC), and then determining the prices of the other project sizes through adjustments.

The base REC price is based on the costs for a 5,000 kW AC project. The modified CREST model was run to calculate the PV COE for the 5,000 kW AC system size in order to set the base REC price to which pricing bin adjustments are applied.

The present-value cost of energy ("PV COE") for each project size is calculated over the project useful life, 25 years, by taking the present value of fifteen or twenty year tariff price (i.e. the total dollar value incentive necessary for a project to cover its costs and achieve a necessary economic return to the project developer and/or subscribers) and ten or five years of present value expected post-tariff market revenues, depending on the REC Program Category.

The raw PV COE output calculated using the cash flows from the modified version of the CREST model for the 5,000 kW AC system size is not the final base REC price. The present value of the expected net metering revenues (as described in the following section) over 25 years by utility must therefore be subtracted from the PV COE to get the revenue shortfall – which, after dividing by the expected production over the first 15 years, is equivalent to the net PV COE or the final base REC price.

REC prices are not derived from only the PV COE output from the model as the REC price is set by subtracting any net metering credits, which differ by Block Group, from the PV COE to arrive at the final base REC price as shown below.

> Base REC Price ($/REC)[19] = 25-year PV COE for 5,000 kW ($) – 25-year PV Utility Net Metering Credits at 80% ($) / 15-year REC production (MWh)[20]

After calculating the base REC price for a 5,000 kW AC system, pricing bin adjustments were calculated for the other distributed generation bins, i.e., (i) up to 10 kW AC, (ii) greater than 10 to 25 kW AC, (iii) greater than 25 to 100 kW AC, (iv) greater than 100 to 200 kW AC, and (v) greater than 200 to 500 kW AC, and (vi) greater than 500 to 2,000 kW AC, based on a midpoint approach using the IPA's modified CREST model output for the bin size bookends. The pricing bin adjustments were calculated using the net PV COE output from the modified

[19] One REC is equal to one megawatt-hour ("MWh") of electricity generated such that $/REC are equivalent to $/MWh.

[20] For ABP traditional community solar and public schools the 20-year REC production is used to reflect the 20-year contract term.

CREST model for each of the system sizes that bookend a pricing bin. The net PV COE for each system size is calculated by subtracting the relevant net metering credits after accounting for subscriber savings for the system size from the modeled PV COE output for that system size. To calculate the adjustment for each size-based bin, the midpoint between the net PV COE for the two bookend system sizes was calculated. The adjustment for each pricing bin is added to the base REC price. Each adjustment is the difference between (i) the midpoint of the calculated Net PV COE for the two bookend system sizes for that bin, and (ii) the base REC price. Adjustments differ by Block Group because the net metering tariffs differ between the two largest utilities that represent Group A and Group B.[21] By way of example, the 100 to 200 kW AC adjustment was calculated as shown below:

> [greater than 100 to 200 kW AC Adjustment] = [average of 100 kW AC Net PV COE & 200 kW AC Net PV COE] – [Base REC Price]

The smallest system size for small distributed generation incorporates any system up-to10 kW AC, while the smallest system size for large distributed generation incorporates any system up to 25 kW AC. The adjustment for the smallest system size (i.e., up to 10 kW for small distributed generation and up to 25 kW for large distributed generation and community solar) is the difference between the Net PV COE for a 10 kW AC or 25 kW AC system and the base REC price for the Block Category.

Resulting REC prices for each Block Category represent the base REC price as calculated using the modified CREST model and the calculated pricing bin adjustments that are applied to the successively smaller project size bins.

## Net Metering Credit

There were previously three bill charge categories that may fall under the net metering tariff that are assumed credits to ABP or ILSFA participants, including the energy supply, transmission, and distribution volumetric credits.[22] This 2022 Long-Term Plan now includes capacity charges for systems over 25 kW (systems below 25 kW already reflected a bundled energy charge), energy efficiency adjustments, energy transition assistance charges, environmental cost recovery adjustments, renewable energy adjustments, and zero emission adjustments. For the distributed generation model pricing bins, it is assumed that eligible customers will receive the net metering tariff including, as applicable by customer type, the credits for the energy supply, transmission, distribution, capacity charges (excludes small DG), energy efficiency adjustments, energy transition assistance charges, environmental cost recovery adjustments, renewable energy adjustments, and zero emission adjustments charges, as specified by each utility for the corresponding customer class. The present value of the net metering credit over the project useful life for each project

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[21] Group A net metering credits are based on Ameren tariffs while Group B net metering credits are based on ComEd tariffs.

[22] It is assumed that a residential customer with a solar system will receive full retail net metering with all three of these credits. 220 ILCS 5/16-107.5(d), (d-5). A non-residential customer that elected the $250/kW rebate under Section 16-107.6(c)(1) of the Public Utilities Act would no longer be eligible to receive the distribution service rate portion of the net metering credit, but would still receive credits for energy and transmission charges. 220 ILCS 5/16-107.6(c)(3). Moreover, it is assumed that residential customers' existing energy supply rate is the tariffed, bundled rate provided by the utility (Rate BES for ComEd or Rate BGS-1 for Ameren Illinois), while non-residential customers' existing energy supply rate is an hourly rate that can be approximated by the applicable RTO's Locational Marginal Prices ("LMPs") for the applicable geographic area of Illinois.

The community renewable net metering tariffs for ComEd and Ameren approved by the Commission on January 13, 2022 includes credits for the energy supply rate (which includes transmission and capacity), but not distribution rates.

size was calculated on a total dollar basis that accounts for the expected production for each system size.

For systems over large distributed generation and community solar projects, the model includes an assumption that the system is non-residential and elects to take the Smart Inverter Rebate under Section 16-107.6(C)(1) of the Public Utilities Act and thus, not receive net metering distribution credits.[23] The Smart Inverter Rebate is applied as an additional state rebate in the CREST model on a dollar per watt basis at $0.25 per watt DC and treated as taxable income. The net metering credit applied to the pricing bins including project sizes between 10 and 5,000 kW AC assumes therefore only includes the energy supply and transmission credits as part of the expected net metering revenues.[24] The energy supply credit for each utility was calculated by averaging the annual average LMPs for the last five full calendar years (i.e. 2017 through 2021), thereafter escalated at 1% annually, reflecting stakeholder feedback to lower this rate from 2% to 1% for this Plan.[25] Transmission credits for the 2021-2022 delivery year were taken from the utility tariffs. For both Group A and Group B, the transmission credit from the utility tariff was simply converted from a ¢/kWh value to a $/kWh value. Capacity charges reflect five years of historical capacity charges and are converted from $/PLC-Day to $/kWh for Group A and from $/kW-Month to $/kWh for Group B.[26] For Group A, there is a single annual value provided as a $/PLC-day, where Peak Load Contribution ("PLC") is defined in Ameren's tariff as "PLC Demand means kW demand assigned to a Customer representing the Customer's share of the forecast MISO system peak demand for the applicable MISO Planning Year." This value is multiplied by the estimated PLC contribution[27] and 365 days to derive the annual capacity charge and divided by the average annual commercial customer usage as calculated using Energy Information Agency ("EIA") 2020 form 861 data. For Group B, the weighted average capacity charge in $/kW-Month is calculated using 4 months of summer and 8 months of winter charges. This value is then translated into a $/kWh value using the Small Delivery Load Class Peak Load Contribution ("PLC") and the average annual commercial customer usage as calculated using the 2020 EIA 861 data. The weighted capacity charge is multiplied by the PLC and 12 to get the annual capacity charge, then divided by annual commercial customer usage from EIA 861.

The net metering credit applied for small distributed generation up-to-10 kW AC pricing bin assumes subscribers will be in the residential rate class. The model did not include the Smart Inverter Rebate, as residential systems are not currently eligible for that rebate under Section 16-107.6(c)(1) of the PUA, but did include net metering distribution credits. The energy supply credit for each utility was calculated as a weighted average of retail purchased electricity charges for the past five Delivery Years; further years are extrapolated from the 2021-2022 delivery year price by escalating the prices at 1%. Transmission credits were calculated in the same manner as they were for the C&I class but instead using the residential class tariff rates. The distribution credit for the Ameren Illinois residential class was

[23] See 220 ILCS 5/16-107.6(c)(1), (3).

[24] See 220 ILCS 5/16-107.6(c)(1), (3). The Model assumes a C&I subscriber will elect the Smart Inverter Rebate and thereby lose net metering credits for distribution charges.

[25] Ibid.

[26] Docket No. 22-0231, Final Order dated July 14, 2022 at 95

[27] The Group B PLC contribution estimate is used for Group A as well.

calculated by taking the weighted average distribution charge in $/kWh of four months of summer and eight months of non-summer tariff rates (for calendar year 2022),[28] while the residential class ComEd customer distribution credits were calculated by multiplying the volumetric distribution charge for calendar year 2021 by the Incremental Distribution Uncollectible Cost Factor ("IDUF") for the residential single family without electric space heat customer class.

Various stakeholders suggested that a measure of subscriber (for community solar) or property owner/participant (for distributed solar) savings be applied to the net metering credit; this savings would be excluded from contributing to the assumed rate of return on the solar generation investment. Table D-1 provides the percentage of net metering value and subscriber savings by Program Category.

**Table D-1 – Net Metering Value Allocation & Subscriber/Participant Savings**

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

## Installation Cost Data

Regarding the inputs to the CREST model, in particular installation cost data, a number of stakeholders suggested that the IPA issue a survey to stakeholders involved in the development of solar projects to determine the inputs to the model. There was a suggestion to use the survey issued by the Massachusetts Department of Energy Resources ("MA DOER") as part of the Solar Massachusetts Renewable Target ("SMART") program. The Agency reviewed the MA DOER Task 1 Report[29] which highlighted data quality concerns arising from the stakeholder survey. In particular, the report noted that self-reported system costs for two of the largest residential installers in the dataset were significantly above the costs reported by other firms.[30] The report deemed the self-reported data from these installers as questionable and removed them from the dataset. Because of concerns regarding data quality, based on the Massachusetts experience, the Agency decided against

[28] Ameren Illinois' volumetric distribution charges differ in summer vs. non-summer.

[29] Task 1 Report: Evaluation of Current Solar Costs and Needed Incentive Levels Across Market Segments. See http://www.mass.gov/eea/docs/doer/rps-aps/doer-post-400-task-1.pdf.

[30] Ibid at section 4.2.1.

issuing a similar survey. As a result, the IPA made a decision to use publicly available data for the REC Pricing Model.

The REC Pricing Model for the 2022 Long-Term Plan uses the NREL Q1 2020 Benchmarking Report, which provides the most detail in terms of cost categories necessary for populating the CREST Model. NREL has provided updated costs in its Q1 2021 Benchmarking Report, however, due to continued decreasing costs from the Q1 2020 report that does not align with stakeholder feedback, the Agency has chosen to use the Q1 2020 to model REC prices for this 2022 Long-Term Plan. The NREL report publishes the following installation cost categories:

- Module
- Inverter
- Balance of System ("BOS")
- Installation Labor & Equipment
- Permitting, Inspection and Interconnection
- EPC[31] Overhead
- Developer Overhead

The NREL Q1 2020 Benchmarking Report models and provides national cost averages for a Residential Solar Project, a Commercial Solar Project, and a Utility Scale Project.[32] The average Residential System modeled in the NREL report is 7 kW DC. The average Commercial System modeled is 200 kW DC. The report, however, also models and provides the costs for 100 kW DC, 500 kW DC, 1,000 kW DC, and 5,000 kW DC systems. The component level costs and how they are rolled up into CREST capital cost categories are shown in Table D-2 through Table D-4 below as well as in the NREL Capital Costs worksheet of Appendix E. The project costs reflect the total installation costs of building the DC system equivalent of an AC system.[33] To convert an AC system to a DC system, a category specific AC-DC conversion loss factor shown in Table D-5 based on observed program project data to date was used. CREST uses DC inputs, therefore while the tables below show the costs for the AC system sizes, the costs are multiplied within the model by each category-specific DC system size.

[31] EPC stands for engineering, procurement, and construction.

[32] Feldman, David, Vignesh Ramasamy, Ran Fu, Ashwin Ramdas, Jal Desai, and Robert Margolis. 2021. U.S. Solar Photovoltaic System Cost Benchmark: Q1 2020. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-77324. https://www.nrel.gov/docs/fy21osti/77324.pdf.

[33] Joint Solar Parties ("JSP") Reply at 23-24.

### Table D-2 – Capital Costs by Component for Residential Projects ($/W dc)

| System Size (kW AC) | 10 |
|---|---|
| Module | 0.49 |
| Inverter | 0.25 |
| Hardware BOS - Structural Components | 0.08 |
| Hardware BOS - Electrical Components | 0.23 |
| Installation Labor | 0.26 |
| Permitting, Inspection and Interconnection (PII) | 0.06 |
| Supply Chain Costs | 0.19 |
| Sales Tax | 0.24 |
| **Total EPC Cost** | **1.80** |
| Sales & Marketing (Customer Acquisition) | 0.43 |
| Overhead (General & Admin.) | 0.27 |
| Net Profit | 0.29 |
| **Total Installation Cost** | **2.79** |

### Table D-3 – Capital Costs by Component for Commercial & Utility-scale Projects ($/W dc)

| System Size (kW AC) | 25 | 100 | 200 | 500 | 2000 | 5000 - Fixed | 5000 - Tracking |
|---|---|---|---|---|---|---|---|
| Module | 0.49 | 0.49 | 0.49 | 0.49 | 0.49 | 0.49 | 0.49 |
| Inverter | 0.12 | 0.12 | 0.12 | 0.12 | 0.12 | 0.05 | 0.05 |
| Hardware BOS - Structural Components | 0.11 | 0.11 | 0.11 | 0.11 | 0.11 | 0.1 | 0.15 |
| Hardware BOS - Electrical Components | 0.15 | 0.15 | 0.13 | 0.13 | 0.12 | 0.13 | 0.13 |
| Installation Labor & Equipment | 0.19 | 0.19 | 0.15 | 0.13 | 0.12 | 0.12 | 0.13 |
| Permitting, Inspection and Interconnection (PII) | 0.14 | 0.14 | 0.11 | 0.09 | 0.08 | 0.07 | 0.07 |
| EPC Overhead | 0.18 | 0.18 | 0.16 | 0.15 | 0.15 | 0.08 | 0.09 |
| Sales Tax | 0.05 | 0.05 | 0.05 | 0.04 | 0.04 | 0.04 | 0.05 |
| **Total EPC Cost** | **1.42** | **1.42** | **1.32** | **1.26** | **1.24** | **1.09** | **1.17** |
| Contingency (4%) | 0.05 | 0.05 | 0.04 | 0.04 | 0.04 | 0.03 | 0.03 |
| Developer Overhead | 0.36 | 0.36 | 0.33 | 0.31 | 0.31 | 0.11 | 0.12 |
| EPC/Developer Net Profit | 0.12 | 0.12 | 0.11 | 0.11 | 0.11 | 0.09 | 0.10 |
| **Total Installation Cost** | **1.95** | **1.95** | **1.80** | **1.72** | **1.69** | **1.32** | **1.42** |

**Table D-4 – Capital Costs by CREST Model Categories ($/kW dc)**

| System Size (kW AC) | 10 | 25 | 100 | 200 | 500 | 2000 | 5000 – Fixed | 5000 - Tracking |
|---|---|---|---|---|---|---|---|---|
| Generation Equipment | $1,014 | $1,011 | $1,011 | $978 | $961 | $954 | $780 | $811 |
| Balance of Plant | $573 | $446 | $446 | $391 | $362 | $349 | $350 | $419 |
| Balance of Plant (Prevailing Wage Labor 32% increase) | $656 | $507 | $507 | $438 | $402 | $387 | $388 | $462 |
| Interconnection | $63 | $136 | $136 | $106 | $88 | $83 | $70 | $68 |
| Development Costs and Fee | $957 | $361 | $361 | $330 | $313 | $306 | $254 | $279 |
| Total | $2,607 | $2,014 | $2,014 | $1,852 | $1,764 | $1,730 | $1,492 | $1,620 |

Previously, the NREL Benchmarking Report costs have been rolled forward by 4% per year to reflect historical trends in solar price declines. The ICC Final Order approving the Plan directed the IPA not to apply the 4% annual reduction to the NREL Q1 2020 Benchmarking Report to the REC Pricing Model.[34]

## Other Cost Data

The REC Pricing Model also relies on the following sources for data on the other costs required to populate the CREST model.

- Financing and operating cost data was obtained from the following sources – (i) CREST model default assumptions, (ii) Elevate Energy's Community Solar model,[35] and (iii) various stakeholder comments on the Draft LTRRPP.
- In response to stakeholder comments and using data provided by stakeholders, the Intermediate category of detail was utilized for operations and maintenance cost.
- Net metering and electricity pricing data was obtained from the utilities' filed tariffs. Historic capacity and purchased energy charges for ComEd were provided by the utility.
- The federal Investment Tax Credit was updated from a 30 percent tax credit as used in the REC Pricing Model for the Initial Plan to 22% to reflect anticipated 2023 step-down.
- On-peak PJM and MISO Locational Marginal Prices ("LMPs") from 2017 to 2021.
- For ABP large distributed generation and community solar projects, a 32% increase was applied to the NREL "Installation Labor and Equipment" category in order to meet prevailing wage requirements for those projects.
- For the up-to-10 kW AC small distributed generation project, the IPA considered the impact of the federal tax law changes regarding bonus depreciation.[36] In this regard, it is the IPA's view that having bonus depreciation at 80% may make third-party ownership of small systems more likely, compared to ownership by a homeowner,

[34] Docket No. 22-0231, Final Order dated July 14, 2022 at 94-5.
[35] https://ipa.illinois.gov/content/dam/soi/en/web/ipa/documents/elevate-energy-l-rrpp-request-comments-20170714-updated.pdf
[36] Bonus depreciation was set at 80% to reflect the applicable bonus depreciation rates for 2023, the first year in which rates are scheduled to step-down. See Docket No. 22-0231, Final Order dated July 14, 2022 at 94.

because being able to capture bonus depreciation will be more attractive. For this reason, the 80% bonus depreciation is now also applied to the up-to-10 kW AC project size.

- The AC-DC conversion factors were based on Part II verified project data, broken out by Group and project size, provided by the Adjustable Block Program Administrator, and capacity factors were based on a PVWatts analysis of those Part II verified projects. For Community Solar, the capacity factors and AC-DC ratios, the DG data were used for 10-500 kW project sizes due to the lack of applicable data from community solar projects. 5000 kW projects were modeled using the same conversion factor and capacity factor as the 2000 kW projects.
- 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.37
- For the 5,000 kW AC systems, the Development Costs and Fees are not based solely on the NREL Q1 2020 data for a utility-scale 5,000 kW AC system. The Development Costs and Fees for 5,000 kW AC systems were calculated by adding an 12% of the Generation Equipment, BOP, and Interconnection to the Developer Overhead for the NREL utility-scale 5,000 kW AC system.

**Table D-5 – AC-DC Conversion Factors and Capacity Factors**

**Group A – Ameren**

| **Generator Nameplate Capacity** | kW ac | 10 | 25 | 100 | 200 | 500 | 2000, 5000 | 2000, 5000 (CS) |
|---|---|---|---|---|---|---|---|---|
| **AC-DC Conversion Factor** | % | 0.80 | 0.83 | 0.84 | 0.83 | 0.83 | 0.82 | 0.69 |
| **Capacity Factor** | % dc | 14.88 | 15.13 | 15.20 | 14.82 | 15.30 | 14.41 | 16.91 |

**Group B – ComEd**

| **Generator Nameplate Capacity** | kW ac | 10 | 25 | 100 | 200 | 500 | 2000, 5000 | 2000, 5000 (CS) |
|---|---|---|---|---|---|---|---|---|
| **AC-DC Conversion Factor** | % | 0.80 | 0.83 | 0.84 | 0.85 | 0.80 | 0.82 | 0.80 |
| **Capacity Factor** | % dc | 13.5 | 13.3 | 14.3 | 14.2 | 14.1 | 15.0 | 16.4 |

# REC Price Calculation

## Adjustable Block Program Models

The modified CREST model, as described above, was run for each ABP Program Category for both Group A and Group B. The model run for each REC Pricing Block reflects specific input

[37] This phrase is currently subject to litigation in ICC Docket No. 20-0700, the interconnection cost estimate should be a uniform $200 (plus an additional $50 for the application fee if that is approved as a separate cost by the Commission).

assumptions described in this Appendix and as shown in the Appendix E spreadsheet model. Table D-6 illustrates the cumulative differences in pricing bins from the base 5,000 kW model.

**Table D-6 – Net PV COE Size Adjustments**

| Bin | Group A ($/REC) | Group B ($/REC) |
|---|---|---|
| ≤10 kW AC | $37.60 | $48.97 |
| > 10 to 25 kW AC | $25.48 | $38.58 |
| > 25 to 100 kW AC | $17.04 | $28.92 |
| > 100 to 200 kW AC | $17.95 | $25.71 |
| > 200 to 500 kW AC | $11.44 | $19.80 |
| > 500 to 2,000 kW AC | $9.52 | $14.32 |
| > 2,000 to 5,000 kW AC | $0.00 | $0.00 |

Table D-7 shows the distributed generation ABP REC price for each Group and pricing bin. For example, the 100 to 200 kW bin REC price is calculated by adding that bin's adjustment ($17.95 for Group A or $25.71 for Group B) to the base REC price of $40.90 for Group A and $33.31 for Group B.

**Table D-7 – Distributed Generation ABP REC Prices**

| Bin | Group A ($/REC) | Group B ($/REC) |
|---|---|---|
| ≤ 10 kW AC | $78.51 | $82.28 |
| > 10 to 25 kW AC | $66.39 | $71.89 |
| > 25 to 100 kW AC | $57.94 | $62.23 |
| > 100 to 200 kW AC | $58.85 | $59.02 |
| > 200 to 500 kW AC | $52.35 | $53.11 |
| > 500 to 2,000 kW AC | $50.42 | $47.63 |
| > 2,000 to 5,000 kW AC | $40.90 | $33.31 |

Community solar projects were modeled under various assumptions that differed from the distributed generation projects. As noted above, community solar projects receive a pricing bin adjustment calculated in the same manner as described for the distributed generation adjustment. Community solar projects all receive a small subscriber adjustment to account for additional costs associated with managing small subscribers, which the Agency has set at $14.82 for this 2022 Long-Term Plan. As described in Chapter 7 of this 2022 Long-Term Plan, the Agency has adopted the midpoint of the range of costs reported by GTM Research, or $14.82/REC for 50% or over small subscriber levels. The small subscriber adder is applied equally to all project sizes for the following two ABP Block Categories: community solar and community-driven solar.

Input assumptions changed for community solar projects, aside from those noted above related to the net metering credit, reflect stakeholder comments and include an increased internal rate of return,[38] the inclusion of MACRS bonus depreciation in federal taxation for all project sizes (including the up-to-10 kW AC size), and additional data on costs facing a community solar project (i.e., land lease, property taxes). Additionally, community solar interconnection costs per were based on actual project data that have been Part II verified by the ABP Program Administrator. The average cost per kW DC was calculated for Group A as $150/kW DC and for Group B as $247/kW DC. These costs were multiplied by the kW DC project size to calculate interconnection costs for Community Solar in each group. Community Solar Pries were also adjusted to reflect a 20-year REC delivery term.

The ABP community solar REC prices are shown in Table D-8.

**Table D-8 – Community Solar REC Prices ($/REC)**

| Bin | Group A ($/REC) | Group B ($/REC) |
|---|---|---|
| ≤ 25 kW AC | $56.23 | $61.54 |
| > 25 to 100 kW AC | $59.19 | $64.39 |
| > 100 to 200 kW AC | $60.85 | $65.23 |
| > 200 to 500 kW AC | $57.22 | $62.09 |
| > 500 to 2,000 kW AC | $51.32 | $55.50 |
| > 2,000 to 5,000 kW AC | $45.50 | $47.78 |

In its Final Order approving the Initial Long-Term Renewable Resources Procurement Plan, the Commission approved a co-location standard for community solar projects as follows: "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. These projects may be co-located in one of two ways: a) two 2-MW projects on one parcel, or b) one 2-MW project on each of two contiguous parcels."[39] The Agency proposes the co-location standard be omitted in light of REC pricing covering systems up to 5,000 kW AC in the 2022 Long-Term Plan.

The 2022 Long-Term Plan includes two new ABP REC Pricing Blocks for Community-driven Solar and Public Schools. Community-driven Solar prices were modeled using the same assumptions as ABP community solar aside from the REC contract duration, which was set to 15 years for community-driven solar. REC prices for community-driven solar are presented in Table D-9.

**Table D-9 – Community-driven Solar REC Prices ($/REC)**

[38] The assumed internal rate of return is 14% in the community solar model instead of 12% in the distributed generation model.

[39] Final Order at 131.

| Bin | Group A ($/REC) | Group B ($/REC) |
|---|---|---|
| ≤ 25 kW AC | $71.60 | $78.27 |
| > 25 to 100 kW AC | $75.34 | $82.16 |
| > 100 to 200 kW AC | $77.27 | $83.42 |
| > 200 to 500 kW AC | $72.47 | $79.19 |
| > 500 to 2,000 kW AC | $64.76 | $70.12 |
| > 2,000 to 5,000 kW AC | $56.85 | $59.44 |

In response to stakeholder comments, the IPA elected to model ABP Public School REC prices in a way that would ensure these prices would incentivize development in that sector. ABP Public School prices were modeled using results from the ABP DG CREST model runs instead of modeling the category REC prices using CREST. Using the ABP DG REC prices (shown in Table D-7), discount rates based on the WACC (shown in Table D-10) and AC-DC ratios and capacity factors (shown in Table D-5) as a starting point, the net present value of the ABP DG over the contracted spend (i.e. 6.5 years) was calculated.[40] Since the ABP Public Schools RECs are paid as-delivered over 20 years, the necessary increase in REC prices under this contract structure to achieve the same NPV was calculated by reviewing various possible percentage increases in the ABP DG REC prices to determine how much higher the revenue requirement would be for ABP Public Schools RECs. ABP Public Schools REC prices are shown in Table D-11.

**Table D-10 - ABP DG Discount Rates**

| Project Size (kW AC) | Discount Rate (%) |
|---|---|
| 10 kW | 8.80% |
| 25 kW | 7.78% |
| 100 kW | 7.84% |
| 200 kW | 7.76% |
| 500 kW | 7.72% |
| 2000 kW | 7.70% |
| 5000 kW | 7.53% |

**Table D-11 – Public Schools REC Prices ($/REC)**

| Bin | Group A ($/REC) | Group B ($/REC) |
|---|---|---|

[40] Note this net present value will not be the same as the net present values shown in the CREST model as it considers the assumed full system life of 25 years to derive the cost of energy and 25 years of net metering revenues.

| | | |
|---|---|---|
| ≤ 25 kW AC | $74.95 | $81.16 |
| > 25 to 100 kW AC | $65.57 | $70.42 |
| > 100 to 200 kW AC | $66.40 | $66.59 |
| > 200 to 500 kW AC | $58.94 | $59.81 |
| > 500 to 2,000 kW AC | $56.73 | $53.59 |
| > 2,000 to 5,000 kW AC | $45.72 | $37.23 |

### Illinois Solar for All Models

There are four Categories under the Illinois Solar for All Program that receive incentives as described in Chapter 8 of the Plan: Low-Income Single-Family and Small Multifamily Solar Incentive (1-4 unit buildings), Low-Income Large Multifamily Solar Incentive (5+ unit buildings), Low-Income Community Solar Project Initiative, and Incentives for Non-Profits and Public Facilities. There is a separate approach used for setting REC prices for each of the four Illinois Solar for All Categories. The Incentives for Illinois Solar for All build on the models used for the Adjustable Block Program. For Low-Income Single-Family and Small Multifamily Solar Incentive (1-4 unit), customer savings allocated from the net metering credit are set to 100%. For Non-Profits and Public Facilities, customer savings allocated from the net metering credit are set at 80%[41]. For Low-Income Large Multifamily Solar Incentive (5+ unit buildings) and Low-Income Community Solar Project Initiative , it is assumed that the customer savings value allocated from the net metering credit is increased from 20% to 50%.

Section 1-56(b)(2) of the Act requires that the Illinois Solar For All incentives deliver tangible economic benefits for eligible low-income subscribers. The incentive payments for the low-income subscribers are intended to be sufficient to provide tangible economic benefits to participants through enabling project developers to eliminate upfront costs to the participants for the installation of photovoltaic projects. The incentive will be a standard incentive and not customized for each project.

The CREST model was used to determine the PV COE for low-income distributed generation participants by setting the debt financing parameter to zero percent, assuming they would have difficulty accessing credit markets, and using the other input assumptions mirroring those used to calculate non-low income distributed generation prices. Pricing bin adjustments were calculated in the same manner as for non-low income distributed generation. Table D-12 provides the REC prices for the low-income distributed generation participants in larger buildings, who are assumed to receive 50% of the net metering value. Table D-13 provides the REC prices for the low-income distributed generation participants in smaller (1-4 unit) buildings, who are assumed to receive 100% of the net metering value. For the 2022 Long-Term Plan an additional adjustment to increase the development costs and fees for smaller (1-4 unit) buildings by 100% to recognize the increased complexity of

[41] Docket No. 22-0231, Final Order dated July 14, 2022 at 95.

developing residential projects as part of Illinois Solar for All compared to the Adjustable Block Program.

**Table D-12 – Low-Income Large Multifamily Solar Incentive REC Prices (5+ Unit Buildings)**

| Bin | Group A ($/REC) | Group B ($/REC) |
|---|---|---|
| ≤ 10 kW AC | $106.87 | $115.50 |
| > 10 to 25 kW AC | $88.31 | $97.05 |
| > 25 to 100 kW AC | $73.26 | $79.36 |
| > 100 to 200 kW AC | $74.04 | $76.40 |
| > 200 to 500 kW AC | $67.95 | $70.82 |
| > 500 to 2,000 kW AC | $66.40 | $65.51 |
| > 2,000 to 5,000 kW AC | $56.54 | $51.31 |

**Table D-13 – Low-Income Single Family and Small Multifamily Solar Incentive REC Prices (1-4 Unit Buildings)**

| Bin | Group A ($/REC) | Group B ($/REC) |
|---|---|---|
| ≤ 10 kW AC | $180.67 | $175.23 |
| > 10 to 25 kW AC | $142.16 | $141.75 |
| > 25 to 100 kW AC | $107.10 | $108.51 |
| > 100 to 200 kW AC | $107.44 | $104.86 |
| > 200 to 500 kW AC | $100.28 | $98.93 |
| > 500 to 2,000 kW AC | $98.32 | $93.22 |
| > 2,000 to 5,000 kW AC | $86.65 | $77.18 |

As described in Chapter 8 of the Plan, the Low-Income Community Solar Project Initiative is intended to support participation in community solar by low-income subscribers. For Low-Income Community Solar Project Initiative participants, a different approach was used than the zero percent debt financing used for the Low-Income Distributed Generation Incentives. While the non-low income community solar REC price was calculated using the assumption of a 20-year payback period, the REC prices for this group was calculated using a shortened, 5-year payback period and a lower assumed 35% debt financing. REC prices for participants of Low-Income Community Solar Project Initiative are shown in Table D-17 and include the additional $14.82 per REC for small subscriber participation described above. Low-Income Community Solar values in Table D-14 build upon the non-low income community solar REC prices in Table D-12 under altered assumptions discussed above.

**Table D-14 – Low-Income Community Solar Project Initiative REC Prices**

| Bin | Group A ($/REC) | Group B ($/REC) |
|---|---|---|
| ≤ 25 kW AC | $94.50 | $104.81 |
| > 25 to 100 kW AC | $98.75 | $109.13 |
| > 100 to 200 kW AC | $101.09 | $110.76 |
| > 200 to 500 kW AC | $96.10 | $106.32 |
| > 500 to 2,000 kW AC | $87.49 | $96.43 |
| > 2,000 to 5,000 kW AC | $78.01 | $83.80 |

Section 1-56(b)(2)(C) of the Act also specifies that "non-profits and public facilities" will be eligible to receive incentives for on-site photovoltaic generation. These incentives are designed to "support on-site photovoltaic distributed renewable energy generation devices to serve the load associated with not-for-profit subscribers and to support photovoltaic distributed renewable energy generation that uses photovoltaic technology to serve the load associated with public sector subscribers taking service at public buildings."[42] To calculate the Incentives for Non-Profits and Public Facilities participants, the input assumptions remained the same as those used for low-income distributed generation in all but two categories. The owner was not considered to be a taxable entity for the purposes of calculating the Incentives for Non-Profits and Public Facilities, and the up-to-10 kW AC project size was considered to be a C&I subscriber, reflected in the net metering credit applied as well as the inclusion of the Smart Inverter Rebate for all project sizes. REC prices for the Incentives for Non-Profits and Public Facilities are provided in Table D-15.

**Table D-15 – Incentives for Non-Profits and Public Facilities REC Prices**

| Bin | Group A ($/REC) | Group B ($/REC) |
|---|---|---|
| ≤ 25 kW AC | $100.76 | $114.60 |
| > 25 to 100 kW AC | $104.21 | $114.05 |
| > 100 to 200 kW AC | $104.82 | $109.82 |
| > 200 to 500 kW AC | $98.15 | $104.03 |
| > 500 to 2,000 kW AC | $96.39 | $97.71 |
| > 2,000 to 5,000 kW AC | $85.22 | $80.19 |

[42] 20 ILCS 3855/1-56(b)(2)(C).