Appendix D - REC Pricing Model Description

REC Pricing Approach

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").[1] 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) revenues received through net metering, (ii) any assumed incentives such as federal tax credits, and (iii) the Distributed Generation Rebate[2] 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,[3] transmission, and distribution charges for the net generation produced by distributed generation projects until net metering accounts for 5% of the total peak demand of the electricity provider's eligible customers. 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, net metering is for energy supply charges only. (Once the 5% level is reached, net metering for all new installations, including distributed generation, will be for energy only.)

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

- up to 10 kW
- greater than 10 to 25 kW
- greater than 25 to 100 kW
- greater than 100 to 200 kW
- greater than 200 to 500 kW
- greater than 500 to 2,000 kW

There is one price for all systems within a bin. 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 draft Long Term Renewable Resources Procurement Plan ("LTRRPP"

[1] The model uses inputs from currently available information, including current utility rates and tariffs. As discussed in Section 6.4 of the Plan, inputs will be updated after the Plan is approved by the Commission in 2018.

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

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

or "Plan").[4] A base price is calculated for the most economic block size (greater than 500 to 2,000 kW), 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 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,[5] while on the cost side, there may be the cost of acquiring, maintaining, and managing subscribers. The initial block price for community solar reflects a baseline for those additional costs and lower revenue. To ensure that the benefits of solar energy are widely shared by Illinois residents, the Adjustable Block Program ("ABP") will offer an additional incentive for community solar projects with a higher level of participation by small subscribers. There will therefore be an adder to incentivize small subscriber participation. Projects meeting a small subscriber participation requirement of 25% to 50%, over 50% to 75 %, or greater than 75% will receive the additional adder.

The IPA also notes that the REC prices presented in this Appendix D and in the Plan may change based on updates to the input assumptions as they become available.[6]

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").[7] CREST is widely known and respected in the renewable energy industry. For the purpose of setting REC prices for the ABP, 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 for the blocks.[8]

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 developer and/or investors.

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

[4] The Agency issued the draft LTRRPP on September 29, 2017. The deadline for the submission of stakeholder comments was November 13, 2017.

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

[6] The REC Pricing Model does not currently reflect, for example, any of the possible regulatory changes discussed in Sections 6.8.1 through 6.8.4 of the Plan, which could cause changes to the Model's input assumptions.

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

[8] 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").

support structures.[9] 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:[10]

> *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)[11]. 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, and input from stakeholder responses to both the Request for Comments [12] and the draft LTRRPP.

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

[10] Ibid, pages 3-4.

[11] 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.

[12] The Request for Comments was 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.

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[13] 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.[14] 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 issuing a similar survey. As a result, the IPA made a decision to use publicly available data for the REC Pricing Model.

To develop the REC Pricing Model, several data sources for populating the CREST Model were reviewed and analyzed—including but not limited to (i) NREL Q1 2017 Benchmarking Report,[15] (ii) LBNL Tracking the Sun Report – September 2017,[16] (iii) NREL Open PV Report,[17] and (iv) SEIA/GTM Research (US Solar Market Insight – Q2 2017).[18] While all reviewed reports provide national average data, due to the immaturity of the Illinois solar market, the reports do not provide detailed Illinois-specific installation cost data.

The REC Pricing Model uses the NREL Q1 2017 Benchmarking Report, which provides the most detail in terms of cost categories necessary for populating the CREST Model. The report publishes the following installation cost categories:

- Module
- Inverter
- Balance of System ("BOS")
- Installation Labor & Equipment
- Permitting, Inspection and Interconnection
- EPC[19] Overhead
- Developer Overhead

[13] 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.

[14] Ibid at section 4.2.1.

[15] https://www.nrel.gov/docs/fy17osti/68925.pdf.

[16] https://emp.lbl.gov/publications/tracking-sun-10-installed-price.

[17] https://openpv.nrel.gov.

[18] Report available through subscription.

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

The NREL Q1 2017 Benchmarking Report models and provides national cost averages for a Residential Solar Project, a Commercial Solar Project, and a Utility Scale Project. The average Residential System modeled in the NREL report is 5.7 kW. The average Commercial System modeled is 200 kW. The report, however, also models and provides the costs for 100 kW, 500 kW, and 1,000 kW systems.

Table D-1 through Table D-6 provide an analysis of the installation costs based on the NREL Report.

Table D-1 - Residential Solar PV Installed Costs (Scaled from 5.7 kW System)

			Total Project Cost ($)
	$/W DC	**$/kW DC**	**10 kW**
Module	0.35	350	**$3,500**
Inverter	0.19	193	**$1,935**
Hardware BOS - Structural Components	0.11	113	**$1,134**
Hardware BOS - Electrical Components	0.24	244	**$2,443**
Supply Chain Costs	0.42	419	**$4,187**
Sales Tax	0.09	89	**$889**
Installation Labor	0.30	304	**$3,039**
Permitting, Inspection and Interconnection (PII)	0.10	96	**$956**
Total EPC Cost	**1.81**	**1,808**	**$18,083**
Sales & Marketing (Customer Acquisition)	0.34	343	**$3,428**
Overhead (General & Admin.)	0.31	308	**$3,079**
Net Profit	0.35	346	**$3,460**
Total Development Cost	**1.00**	**997**	**$9,966**
Total Installation Cost	**2.80**	**2,805**	**$28,049**
NREL Model Categories			
Generation Equipment			**$8,513**
Balance of Plant			**$10,803**
Interconnection			**$956**
Development Costs and Fee			**$7,777**
Total			**$28,049**

Table D-2 - Installed Costs (25 kW System)[20]

	Total Project Cost ($)
	25 kW
NREL Model Categories	
Generation Equipment	**$22,007**
Balance of Plant	**$20,597**
Interconnection	**$3,120**
Development Costs and Fee	**$14,680**
Total	**$60,405**

[20] Costs for the 25 kW system reflect an average of the installed costs for a system scaled upwards from 5.7 kW and a system scaled downwards from 100 kW. The 25 kW system size was incorporated in response to various stakeholder comments on the Draft LTRRPP.

Table D-3 - Commercial PV Installed Costs (100 kW System)

			Total Project Cost ($)
	$/W DC	**$/kW DC**	**100 kW**
Module	0.35	350	**$35,000**
Inverter	0.10	104	**$10,435**
Hardware BOS - Structural Components	0.15	145	**$14,542**
Hardware BOS - Electrical Components	0.19	191	**$19,073**
Installation Labor & Equipment	0.23	231	**$23,138**
Permitting, Inspection and Interconnection (PII)	0.15	154	**$15,400**
EPC Overhead	0.22	216	**$21,636**
Sales Tax	0.05	55	**$5,462**
Total EPC Cost	**1.45**	**1,447**	**$144,686**
Contingency (4%)	0.05	51	**$5,130**
Developer Overhead	0.40	397	**$39,674**
EPC/Developer Net Profit	0.13	133	**$13,264**
Total Installation Cost	**2.03**	**2,028**	**$347,440**
NREL Model Categories			
Generation Equipment			**$90,927**
Balance of Plant			**$56,753**
Interconnection			**$15,400**
Development Costs and Fee			**$39,674**
Total			**$202,754**

Table D-4 - Commercial PV Installed Costs (200 kW System)

			Total Project Cost ($)
	$/W DC	**$/kW DC**	**200 kW**
Module	0.35	350	**$70,000**
Inverter	0.10	104	**$20,870**
Hardware BOS - Structural Components	0.15	145	**$29,083**
Hardware BOS - Electrical Components	0.15	154	**$30,897**
Installation Labor & Equipment	0.17	169	**$33,717**
Permitting, Inspection and Interconnection (PII)	0.13	127	**$25,317**
EPC Overhead	0.19	187	**$37,489**
Sales Tax	0.05	50	**$10,097**
Total EPC Cost	**1.29**	**1,287**	**$257,470**
Contingency (4%)	0.05	45	**$9,005**
Developer Overhead	0.40	397	**$79,347**
EPC/Developer Net Profit	0.12	121	**$24,208**
Total Installation Cost	**1.85**	**1,850**	**$627,499**
NREL Model Categories			
Generation Equipment			**$171,669**
Balance of Plant			**$93,696**
Interconnection			**$25,317**
Development Costs and Fee			**$79,347**
Total			**$370,030**

Table D-5 - Commercial PV Installed Costs (500 kW System)

			Total Project Cost ($)
	$/W DC	**$/kW DC**	**500 kW**
Module	0.35	350	**$175,000**
Inverter	0.10	104	**$52,174**
Hardware BOS - Structural Components	0.15	145	**$72,708**
Hardware BOS - Electrical Components	0.15	145	**$72,686**
Installation Labor & Equipment	0.14	137	**$68,562**
Permitting, Inspection and Interconnection (PII)	0.11	110	**$55,064**
EPC Overhead	0.18	176	**$87,853**
Sales Tax	0.05	49	**$24,412**
Total EPC Cost	**1.22**	**1,217**	**$608,458**
Contingency (4%)	0.04	42	**$21,135**
Developer Overhead	0.40	397	**$198,368**
EPC/Developer Net Profit	0.12	116	**$57,957**
Total Installation Cost	**1.77**	**1,772**	**$1,494,375**
NREL Model Categories			
Generation Equipment			**$418,531**
Balance of Plant			**$213,955**
Interconnection			**$55,064**
Development Costs and Fee			**$198,368**
Total			**$885,918**

Table D-6 - Commercial PV Installed Costs (Scaled from 1,000 kW System)

			Total Project Cost ($)
	$/W DC	**$/kW DC**	**2,000 kW**
Module	0.35	350	**$700,000**
Inverter	0.10	104	**$208,696**
Hardware BOS - Structural Components	0.15	145	**$290,831**
Hardware BOS - Electrical Components	0.14	140	**$280,452**
Installation Labor & Equipment	0.13	126	**$251,199**
Permitting, Inspection and Interconnection (PII)	0.10	105	**$209,283**
EPC Overhead	0.17	171	**$341,715**
Sales Tax	0.05	48	**$96,265**
Total EPC Cost	**1.19**	**1,189**	**$2,378,441**
Contingency (4%)	0.04	41	**$82,364**
Developer Overhead	0.40	397	**$793,471**
EPC/Developer Net Profit	0.11	114	**$227,799**
Total Installation Cost	**1.74**	**1,741**	**$5,860,517**
NREL Model Categories			
Generation Equipment			**$1,656,839**
Balance of Plant			**$822,482**
Interconnection			**$209,283**
Development Costs and Fee			**$793,471**
Total			**$3,482,076**

Because the programs are expected to launch in 2018, the NREL Q1 2017 Benchmarking Report costs were rolled forward one year by reducing prices[21] by 4% per year, reflecting recent historical trends in solar price declines.[22]

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,[23] 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.
- The federal Investment Tax Credit was extended in 2016 to provide a 30 percent tax credit that would ramp down incrementally through 2021 and remain at 10 percent from 2022 forward.
- Locational Marginal Prices ("LMPs") provided by the Joint Solar Parties.[24]

REC Price Calculation

Distributed Generation Model[25]

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 Plan. Modified assumptions are annotated with a source document and highlighted in yellow in the accompanying REC Pricing Model Excel spreadsheets (see Appendix E). As noted earlier, the approach for REC pricing is based on calculating a base price for the most economic block size (500 - 2,000 kW), and then determining the prices of the other project sizes through adjustments. The base REC price is based on the costs for a 2,000 kW project and is the price for the first Adjustable

[21] The trend reflecting declining costs in recent years could be reversed depending on the outcome of the U.S. International Trade Commission's review of the unfair trade practice petition filed by two U.S. solar panel manufacturers, as described in Section 6.8.4 of the LTRRPP.

[22] Based on stakeholder responses to the Draft Plan, interconnection costs were not rolled forward.

[23] https://www.illinois.gov/sites/ipa/Documents/Elevate-Energy-L-RRPP-Request-Comments-20170714-Updated.pdf.

[24] https://www.illinois.gov/sites/ipa/Documents/2018ProcurementPlan/2018-LTRenewable-Joint-Solar-Parties-Comments.pdf.

[25] Presented in Appendix E-1 - Adjustable Block Program Distributed Generation Pricing Model.

Block Program block. The REC price declines by 4% for each successive block after Block 1, as it is anticipated that necessary incentives will decline with the declining cost of solar. The 4% is based on the average annual drop in solar installation costs as estimated in the NREL Q1 2017 Benchmarking Report.[26] The blocks and prices have been structured with the goal of meeting the procurement targets by the end of the delivery year 2020.

The distributed generation model provides results under two scenarios. For systems over 10 kW to 2,000 kW, the model includes an assumption that the system is non-residential and elects to take the Smart Inverter Rebate and thus, under state law, does not receive net metering distribution credits.[27] For systems up to 10 kW, the model assumes the system is residential and thus does not receive the Smart Inverter Rebate, instead receiving net metering distribution credits.

The Smart Inverter Rebate of $250 per kW, as discussed in Section 6.8.2 of the draft Plan, accounts for a credit of $500,000 for the 2,000 kW system. (It is assumed that if the project is over 10 kW, it elects to take the rebate under Section 16-107.6(c)(1) of the Public Utilities Act.) 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, applicable only to the project sizes larger than 10 kW in the distributed generation model and treated as taxable income.

Similarly, the up-to-10 kW project size in the distributed generation model is treated differently from other project sizes regarding MACRS bonus depreciation under federal income tax law and is assumed not to receive this bonus depreciation.[28]

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 the fifteen 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 years of present value expected post-tariff market revenues.

The raw PV COE output calculated using the cash flows from the modified version of the CREST model for the 2,000 kW system size is not the final base REC price. The present value of the expected net metering revenues (adjusted to 80% of the market value to account for 20% subscriber savings) 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. There are three bill charge categories that may fall under the net metering tariff that are assumed credits to ABP participants, including the energy supply, transmission, and distribution volumetric credits.[29] For the distributed generation model pricing bins, it is

[26] https://www.nrel.gov/docs/fy17osti/68925.pdf.

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

[28] Based on comments from SEIA, the MACRS bonus depreciation in the model was reduced from the default of 50% to 30% for project sizes 25 kW to 2000 kW.

[29] 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

assumed that eligible customers will receive the net metering tariff including, as applicable by customer type, the credits for the energy supply, transmission, and distribution 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 size was calculated on a total dollar basis that accounts for the expected production for each system size. For the distributed generation model, the net metering credit applied to the pricing bins including project sizes between 10 and 2,000 kW assumes subscribers will be in the commercial and industrial ("C&I") rate classes. The net metering credit applied to the up-to-10 kW pricing bin assumes subscribers will be in the residential rate class.

For the distributed generation pricing bins that assume C&I subscribers, only the energy supply and transmission credits were applied as part of the expected net metering revenues.[30] The energy supply credit for each utility was calculated by averaging the annual average LMPs for the last five full calendar years for 2018, escalated at 2% to reflect the assumed inflation rate.[31] Transmission credits for the 2017-2018 delivery year were taken from the utility tariffs. For Ameren Illinois, the transmission credit was calculated by converting the transmission charge as provided in the utility tariff in $/kW-day to a $/kW-Month value, which was further adjusted by the estimated peak load contribution ("PLC") and capacity factor to arrive at a $/kWh value. For ComEd, the transmission credit from the tariff was simply converted from a ¢/kWh value to a $/kWh value.

For systems up to 10 kW, the energy supply credit for each utility was calculated as a weighted average of retail purchased electricity charges ($/kWh) for the four summer and eight non-summer months for the 2017-2018 delivery year; further years are extrapolated from the 2017-2018 delivery year price assuming a 2% annual inflation rate. 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 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 2017),[32] while the residential class ComEd customer distribution credits were calculated by multiplying the volumetric distribution charge for calendar year 2017 by the Incremental Distribution Uncollectible Cost Factor ("IDUF") for the residential single family without electric space heat customer class.[33]

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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 tariff for ComEd approved by the Commission on September 27, 2017 includes credits for only the energy supply rate (which includes capacity), but not transmission or distribution rates. Ameren Illinois' net metering tariff approved by the Commission on the same date credits community renewable net generation at the energy supply rate.

[30] 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.

[31] Ibid.

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

[33] The Agency will update these figures after the Illinois Commerce Commission approves new calendar-year 2018 distribution rates for ComEd and Ameren Illinois in December 2017, in Docket Nos. 17-0196 and 17-0197, respectively.

Various stakeholders suggested that a measure of subscriber (for community solar) or property owner (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. In the distributed generation model, 20% customer savings was suggested and applied, thus reducing the net metering credit value to 80%. Table D-7 shows the 25-year present value net metering credit for each project size at 80% for both Ameren Illinois and ComEd for the distributed generation model.

Table D-7 - 25-year Present Value Net Metering Credit at 80% ($)[34]

System Size	Ameren Illinois	ComEd
10 kW	$17,339	$19,238
25 kW	$19,895	$23,200
100 kW	$79,579	$92,801
200 kW	$159,157	$185,602
500 kW	$397,893	$464,004
2000 kW	$1,591,573	$1,856,018

The modified CREST model, including the Smart Inverter Rebate as described above, was run to calculate the PV COE for the 2,000 kW system size in order to set the base REC price to which pricing bin adjustments are applied. For the up-to-10 kW category, 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.

Ameren Illinois and ComEd 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 utility, from the PV COE to arrive at the final base REC price as shown below.

> Base REC Price ($/REC)[35] = 25-year PV COE for 2,000 kW ($) – 25-year PV Utility Net Metering Credits at 80% ($) / 15-year REC production (MWh)

After calculating the base REC price for a 2000 kW system, pricing bin adjustments were calculated for the other distributed generation bins, i.e., (i) up to 10 kW, (ii) greater than 10 to 25 kW, (iii) greater than 25 to 100 kW, (iv) greater than 100 to 200 kW, and (v) greater than 200 to 500 kW, 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 CREST model for each of the system sizes that bookend a pricing bin as shown in Table D-8. 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

[34] References to "Ameren Illinois" and "ComEd" in this Table D-7 as well as subsequent tables in this Appendix D, denote "Group A" and "Group B" described in Chapter 6 of the Plan.

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

the two bookend system sizes was calculated. The adjustment for each pricing bin is on top of 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 utility because the net metering tariffs differ between the two largest utilities. The resulting adjustment for each utility and pricing bin is shown in Table D-9. By way of example, the 100 to 200 kW adjustment was calculated as shown below:

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

The smallest system size incorporates any system up to 10 kW. As noted above, for distributed generation, this is assumed to be a residential system. The adjustment for the up to 10 kW size is the difference between the Net PV COE for a 10 kW system and the base REC price for distributed generation.

Table D-8 - Modified CREST Model Results[36]

System Size	Ameren Illinois Net PV COE ($/MWh)	ComEd Net PV COE ($/MWh)
10 kW	$82.48	$74.03
25 kW	$67.01	$61.12
100 kW	$50.00	$44.12
200 kW	$41.50	$35.62
500 kW	$38.23	$32.35
2000 kW	$37.57	$31.69

Table D-9 shows the distributed generation pricing bin adjustments for each utility and Table D-10 shows the distributed generation ABP REC price for each utility and pricing bin. For example, the 100 to 200 kW bin REC price is calculated by adding that bin's adjustment ($8.18) to the base REC price of $31.69 for ComEd or $37.57 for Ameren Illinois.

[36] The results in this table are the PV COE output from the CREST model prior to subtracting the net metering credits shown in Table D-7 from the PV COE and dividing by the expected REC production over 15 years.

Table D-9 – Distributed Generation Pricing Bin Adjustments for Each Utility[37]

Bin	Ameren Illinois Adjustment ($/REC)	ComEd Adjustment ($/REC)
≤ 10 kW	$44.91	$42.34
> 10 to 25 kW	$37.17	$35.89
> 25 to 100 kW	$20.93	$20.93
> 100 to 200 kW	$8.18	$8.18
> 200 to 500 kW	$2.29	$2.29
> 500 to 2,000 kW	$0.00	$0.00

Table D-10 – Distributed Generation ABP REC Prices

Bin	Ameren Illinois REC Price ($/REC)	ComEd REC Price ($/REC)
≤ 10 kW	$82.48	$74.03
> 10 to 25 kW	$74.75	$67.58
> 25 to 100 kW	$58.51	$52.62
> 100 to 200 kW	$45.75	$39.87
> 200 to 500 kW	$39.87	$33.98
> 500 to 2,000 kW	$37.57	$31.69

Community Solar Model[38]

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, and an adder to incentivize small subscriber participation. Projects that meet or exceed a 25%, 50%, or 75% requirement for small subscriber[39] participation will receive the additional adder ("the Small Subscriber Participation Adder"). The calculation of the community solar pricing bin adjustments and adders is based on changing the assumptions to the net metering credit and changing some of the model input assumptions. For ComEd, as approved by the Commission on September 27, 2017 in Docket No. 17-0350, the net metering credit includes energy supply charges but does not include transmission or distribution charges. For Ameren Illinois, as approved by the Commission on September 27, 2017 in tariff no. ERM 17-144, the tariff credits the energy service bills of subscribers at the "tariffed or contract rate for electricity supply as appropriate." The tariffed or contract rate does not include transmission or distribution

[37] Pricing bin adjustments for the up-to-10 kW system size and the 10-25 kW system size (i.e. the two smallest pricing bins) are unequal across the two utilities because the change in net metering credits from C&I to residential differs across the two utilities' tariffs while the PV COE does not.

[38] Presented in Appendix E-2 - Adjustable Block Program Community Solar Pricing Model.

[39] "Small subscriber" is used to mean residential or small commercial customer subscribers, as referenced in Section 1-75(c)(1)(N) of the IPA Act. These are identified using their subscription sizes: any subscription below 25 kW is assumed to be by a "small subscriber."

charges. For community solar projects, all project sizes were assumed to receive energy-only C&I net metering credits based on the five-year average LMP after accounting for 20% subscriber savings. Additionally, all community solar project sizes were assumed to take the Smart Inverter Rebate applied to the project in the same manner as it was applied to distributed generation projects 10 kW or larger.[40] Table D-11 shows the 25-year present value net metering credit for each project size at 80% for both Ameren Illinois and ComEd for the community solar model.

Table D-11 - 25-year Present Value Net Metering Credit at 80% ($)

Customer Class	Ameren Illinois	ComEd
10 kW	$5,591	$6,860
25 kW	$13,979	$17,150
100 kW	$55,915	$68,600
200 kW	$111,829	$137,201
500 kW	$279,573	$343,002
2000 kW	$1,118,294	$1,372,007

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,[41] the inclusion of MACRS bonus depreciation in federal taxation for all project sizes (including the up-to-10 kW size), and additional data on costs facing a community solar project (i.e., land lease, property taxes). REC prices for community solar projects for each utility were calculated in the same manner as distributed generation REC prices where a base community solar REC price was calculated and calculated pricing bin adjustments applied to the successively smaller project size bins. By way of example, the community solar price for the greater than 100 to 200 kW is the difference between the greater than 100 to 200 kW adjustment and the base community solar REC price. The resulting community solar pricing bin adjustments are shown in Table D-12[42] and community solar REC prices are shown in Table D-13 below.

[40] A community solar project, or its subscribers, are entitled to receive the Smart Inverter Rebate. 220 ILCS 5/16-107.6(f).

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

[42] Due to the same net metering credit being applied to all system sizes, the community solar pricing bin adjustments do not vary by utility in pricing bins that include the 10 kW project size.

Table D-12 – Community Solar Pricing Bin Adjustments ($)

Bin	Ameren Illinois REC Price ($/REC)	ComEd REC Price ($/REC)
≤ 10 kW	$54.51	$54.51
> 10 to 25 kW	$42.95	$42.95
> 25 to 100 kW	$22.23	$22.23
> 100 to 200 kW	$8.83	$8.83
> 200 to 500 kW	$2.62	$2.62
> 500 to 2,000 kW	$0.00	$0.00

Table D-13 – Community Solar REC Prices ($/REC)

Bin	Ameren Illinois REC Price ($/REC)	ComEd REC Price ($/REC)
≤ 10 kW	$111.44	$105.79
> 10 to 25 kW	$99.88	$94.24
> 25 to 100 kW	$79.17	$73.52
> 100 to 200 kW	$65.76	$60.12
> 200 to 500 kW	$59.55	$53.91
> 500 to 2,000 kW	$56.93	$51.29

The IPA received comments from several stakeholders related to the Residential Participation Adders published in the draft Plan. To address those comments (and note that the Agency also updated the Adders to reflect "small subscribers" rather than residential participation), the IPA utilized a recommendation by the Coalition for Community Solar Access[43] to use the results of an analysis by the Rhode Island Office of Energy Resources ("RIOER") on cost assumptions for community solar. RIOER conducted an industry survey on community solar administrative costs related to projects that allocate at least 50% of their capacity to subscription sizes of 25 kW or less. The RIOER survey results were that the upfront (one time) subscriber acquisition costs associated with these projects are $0.25/Watt, and that the ongoing (annual) costs associated with subscriber replacement is $0.02/Watt/year, and the ongoing (annual) cost of subscriber management and billing is about $0.01/Watt/year.[44]

In order to determine the Small Subscriber Participation Adders, the IPA also relied on data on project size, and project energy production provided by Elevate Energy in their comments on the draft Plan.[45] In their comments, Elevate Energy modelled a 1,250 kW

[43] https://www.illinois.gov/sites/ipa/Documents/2018ProcurementPlan/2018-LTRenewable-Coalition-for-Community-Solar-Access-Comments.pdf.

[44] SEA. (2016) Rhode Island Renewable Energy Growth Program: 2017 2nd Draft Ceiling Price Recommendations. Available at: http://sos.ri.gov/documents/publicinfo/omdocs/minutes/6154/2016/49211.pdf.

[45] https://www.illinois.gov/sites/ipa/Documents/2018ProcurementPlan/2018-LTRenewable-Elevate-Energy-Comments.pdf.

system with an energy production of 33,794 MWh over 25 years. *First*, to determine the incremental lifetime subscriber costs for 50% Small Subscriber Participation, the IPA calculated the total $/Watt costs for 50% small subscriber participation as determined by RIOER, by adding the upfront costs to the present value of the ongoing costs, discounted over a 25-year period using the 6% discount rate that is used in the REC Pricing Model. The total cost is $0.76/Watt. *Second,* the IPA calculated the total project costs by multiplying the total cost in $/Watt and the project size of 1,250 kW. The total project cost is $944,898. *Third*, the IPA calculated the Gross 50% Small Subscriber Participation Adder by dividing the total project cost by the project's energy production over 25 years. The resultant adder is $27.96/REC. *Fourth*, the IPA adjusted the adder to account for the net metering revenue a subscriber would receive. In this regard, using the REC Pricing Model, the IPA determined the difference between the residential and C&I net metering values for both ComEd and Ameren, to take into account the difference between the bundled energy supply rate and the LMP for each of the two utilities. The IPA then applied a 2% escalation factor to the net metering credit values for the two utilities for 25 years, and subsequently calculated the net present value of all the annual differences using the 6% discount rate.

Through extrapolation, the values were scaled down accordingly to match a 50% small subscriber participation level. The IPA then divided the present values by 25 to determine annual values of $6.19/REC for ComEd and $5.62/REC for Ameren ("the Annual Net Metering Values"). Next, the IPA subtracted the Annual Net Metering Values from the Gross 50% Small Subscriber Participation Adder to determine the net adders ("the 50% Small Subscriber Participation Adders"). The 50% Small Subscriber Participation Adder for ComEd is $21.77/REC and for Ameren is $22.34/REC. Finally, the IPA determined the adders for small subscriber participation levels of 25% and 75%, through extrapolation. The Community Solar Small Subscriber Participation Adders are presented in Table D-14.

Table D-14– Community Solar Small Subscriber Participation Adders

Small Subscriber Participation (%)	Ameren Illinois Adder ($/REC)	ComEd Adder ($/REC)
Less than 25%	No Adder	No Adder
≥ 25 - 50%	$11.17	$10.88
≥ 50 - 75%	$22.34	$21.77
≥ 75%	$33.51	$32.65

Illinois Solar for All Models[46]

There are three groups under the Illinois Solar for All Program that receive incentives as described in Chapter 8 of the Plan: Low-Income Distributed Generation Initiative, 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 three

[46] Presented in Appendices E-3 - Illinois Solar for All Distributed Generation Incentive Pricing Model, E-4: Illinois Solar for All Community Solar Pricing Model, and E-5: Illinois Solar for All Non-profit and Public Facility Pricing Model.

Illinois Solar for All groups. The Incentives for Illinois Solar for All build on the models used for the Adjustable Block Program. For all three groups, 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, and Table D-15 provides the REC prices for the low-income distributed generation participants.

Table D-15 – Low-Income Distributed Generation Initiative REC Prices

Bin	Ameren Illinois REC Price ($/REC)	ComEd REC Price ($/REC)
≤ 10 kW	$150.58	$145.30
> 10 to 25 kW	$132.43	$127.95
> 25 to 100 kW	$102.56	$98.89
> 100 to 200 kW	$85.31	$81.63
> 200 to 500 kW	$77.17	$73.49
> 500 to 2,000 kW	$73.91	$70.24

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 Initiative. While the non-low income community solar REC price was calculated using the assumption of a 15-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-16. Low-Income Community Solar values in Table D-16 build upon the non-low income community solar REC prices in Table D-13 under altered assumptions discussed above.

Table D-16 – Low-Income Community Solar Project Initiative REC Prices

Bin	Ameren Illinois REC Price ($/REC)	ComEd REC Price ($/REC)
≤ 10 kW	$156.21	$152.68
> 10 to 25 kW	$142.05	$138.52
> 25 to 100 kW	$115.82	$112.29
> 100 to 200 kW	$97.87	$94.34
> 200 to 500 kW	$89.71	$86.18
> 500 to 2,000 kW	$86.12	$82.59

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."[47] 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 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-17.

Table D-17 – Incentives for Non-Profits and Public Facilities REC Prices

Bin	Ameren Illinois REC Price ($/REC)	ComEd REC Price ($/REC)
≤ 10 kW	$147.88	$144.20
> 10 to 25 kW	$133.25	$129.57
> 25 to 100 kW	$107.83	$104.15
> 100 to 200 kW	$91.82	$88.15
> 200 to 500 kW	$84.31	$80.63
> 500 to 2,000 kW	$81.37	$77.69

[47] 20 ILCS 3855/1-56(b)(2)(C).