ILLINOIS POWER AGENCY

Long-Term Renewable Resources Procurement Plan
REC Pricing Model

February 27, 2018 Update

Through the accompanying motion, the Illinois Power Agency ("IPA" or "Agency") hereby proposes the following changes to the portions of its Long-Term Renewable Resources Procurement Plan ("LTRRPP" or "Plan) and related Appendices that describe its REC pricing model for the Adjustable Block Program and Illinois Solar for All Program. Specifically, the Agency is modifying its REC pricing model to reflect (i) recent changes in federal tariff and tax law;[1] (ii) recent changes to delivery rates approved by the Illinois Commerce Commission ("Commission" or "ICC") and other updates to utility rates; (iii) changes that would be required were the Commission to adopt the Proposed Order issued on February 26, 2018 in this proceeding; and (iv) related and additional changes that the Agency believes are warranted and reasonable to update the accuracy of the model. Specific changes, along with an accompanying explanation, are grouped by these categories in the paragraphs below.

The Agency is filing these modifications prior to the Commission's final approval[2] of the Plan to afford interested parties an opportunity to offer comment on the proposed changes. The Agency is also filing an updated Appendix D and making native Excel versions of updated Appendices E-1 through E-5 available on its website[3] as of the date and time of this filing. **The Agency is not, however, waiving its right under the Plan[4] to update inputs in the pricing model further and publish a final version of the model and final REC prices as a compliance filing[5] within 60 days after the Commission's approval of the Plan.[6]**

Solar Component Import Tariffs

In January 2018, U.S. President Donald Trump announced the imposition of tariffs on the import of crystalline silicon photovoltaic cells and modules pursuant to his authority under

[1] The Agency previously committed in its Plan at page 111 to file this update whenever solar component tariffs were announced by the U.S. President. The Agency committed in its Reply at page 22 to also include in the same update an incorporation of recent federal tax law changes.

[2] Approval is due by April 3, 2018, following filing of the Plan on December 4, 2017. See 220 ILCS 5/16-111.5(b)(5)(ii)(C).

[3] See https://www2.illinois.gov/sites/ipa/Pages/2018-Long-Term-Renewable-Appendices.aspx.

[4] See Plan at 98.

[5] See IPA Reply at 22-23.

[6] Finally, the Agency is not waiving its right to make future adjustments of no more than 25% to elements of the final REC pricing model, under Section 1-75(c)(1)(M) of the Illinois Power Agency Act, 20 ILCS 3855/1-75(c)(1)(M).

Section 203(a) of the federal Trade Act, 19 U.S.C. § 2253(a).[7] The tariffs will last for 4 years, starting February 7, 2018. For solar cells, following the first 2,500 MW of imports in any year, the duty rate will be 30% in the first year, then 25% in the second year, then 20%, then 15%. For solar modules, the same annual duty rates apply, without any exemption.

As stated in Section 6.8.4 of the Plan, the Agency intended to update the REC pricing model to reflect any changes in solar project costs following the actual implementation of any trade restriction measures by the President. Following review and analysis, the Agency has decided to modify the REC pricing model by assuming an increase in the cost of generation equipment equal to 8 cents per watt DC. As shown on Appendix D, page 8, Table D-6, the assumed cost of generation equipment for a large distributed generation ("DG") system, using 2017 National Renewable Energy Laboratory ("NREL") figures, is now 90 cents per watt DC, up from 82 cents per watt DC before the tariff increase.[8] The total installation cost of such a system is assumed to be 1.82 cents per watt DC, up from 1.74 cents per watt DC. Thus, the Agency's assumption of an 8-cent/watt increase represents a 4.6% increase in the assumed total project cost. These assumptions are reflected on the Input Assumptions tab of each spreadsheet.

Federal Tax Law Changes

Federal Corporate Income Tax Rate

Following the enactment of Public Law 115-97 on December 22, 2017, the federal corporate income tax rate was reduced from 35% to 21%.[9] This change is now implemented at cell G74 of the CREST Inputs tab in all of Appendices E-1 to E-5.

Federal Tax Depreciation

The REC pricing model used in the filed Plan assumed 30% bonus tax depreciation for a distributed generation or community solar system, reflecting existing federal tax law and comments from the Joint Solar Parties ("JSP").[10] Public Law 115-97, discussed above, also authorized 100% bonus depreciation for property placed in service after September 27, 2017 and before January 1, 2023.[11] Accordingly, the REC pricing model has made this change at cell P71 of the CREST Inputs tab in all spreadsheets.

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[7] See https://ustr.gov/about-us/policy-offices/press-office/press-releases/2018/january/president-trump-approves-relief-us (January 22, 2018); https://www.whitehouse.gov/presidential-actions/presidential-proclamation-facilitate-positive-adjustment-competition-imports-certain-crystalline-silicon-photovoltaic-cells (January 23, 2018); https://www.gpo.gov/fdsys/pkg/FR-2018-01-25/pdf/2018-01592.pdf (January 25, 2018).

[8] This includes the cost categories Module, Inverter, EPC Overhead, Sales Tax, Contingency, and EPC/Developer Net Profit.

[9] See Pub. Law 115-97 (Dec. 22, 2017), https://www.congress.gov/115/bills/hr1/BILLS-115hr1enr.pdf, at § 13001 (modifying 26 U.S.C. § 11(b) and other provisions of the Internal Revenue Code).

[10] JSP Comments to Draft Plan at 13.

[11] Pub. Law 115-97, at § 13201 (modifying 26 U.S.C. § 168(k)(6)).

Additionally, the 100% bonus depreciation is now applied to all system sizes, including the under 10 kW system in the distributed generation model (assumed to be residential). Previously, DG systems under 10 kW in size were assumed to be owned by the homeowner, meaning that bonus depreciation for tax purposes was assumed to be unavailable. It is the IPA's view that having bonus depreciation at 100% may make third-party ownership of small systems more likely by virtue of a more beneficial incentive structure for capturing bonus depreciation.

Changes to Utility Rates

Delivery Rates

Following the Commission's delivery service rate orders in Dockets 17-0196 and 18-0034 (Commonwealth Edison Company or "ComEd") and 17-0197 and 18-0210 (Ameren Illinois Company or "Ameren") in December 2017 through February 2018, the Agency is proposing to update the volumetric delivery service charges for residential customers found in the REC pricing models for distributed generation projects (Appendices E-1 and E-3), based on the expected delivery service rates for calendar year 2018 published by those two utilities and approved by the Commission. For Ameren, the volumetric delivery rate for the residential class is 3.314 cents[12] per kWh, down from the 3.338 cents per kWh rate previously used in the Agency's filed Plan. For ComEd, the volumetric delivery rate for the residential class,[13] after accounting for the $IDUF_R$ factor, is 3.181 cents per kWh, down from the 3.484 cents per kWh previously used in the Agency's filed Plan. These changes will affect the projected long-term net metering revenues for a small (≤10 kW) distributed generation project.

Transmission Rates

Due to the change in capacity factor assumption discussed below, the transmission charge assumed for Ameren residential customers changed from 1.3191 cents per kWh to 1.6018 cents. The transmission charge assumed for Ameren commercial and industrial customers changed from 1.2976 cents per kWh to 1.5760 cents. These changes are implemented in attached Appendices E-1, E-3, and E-5.

For ComEd commercial and industrial customers with distributed generation projects, the volumetric transmission charge assumed in the filed Plan was based on the PJM Services Charges that are Supplement[al] to Rate BES. However, as commercial and industrial customers will receive electric supply on Rate BESH (Basic Electric Service – Hourly), the PJM Services Charge that is Supplement[al] to Rate BESH is more appropriate, as the Joint

[12] This figure is based on a time-weighted average of the summer delivery charge (4.581 cents per kWh) and the non-summer delivery charge for the first 800 kWh in a month (2.681 cents per kWh).

[13] Specifically, the no space heat, single family subclass within the residential class.

Solar Parties argued[14] and the Agency agreed.[15] Thus, for ComEd commercial and industrial customers with distributed generation projects (i.e., projects larger than 10 kW), the assumed volumetric transmission charge is now decreased to 0.844 cents per kWh from 1.327 cents. These changes are implemented in attached Appendices E-1, E-3, and E-5.

Changes Adopted in Proposed Order

AC-DC Conversion Factor

In Objections, the Joint Solar Parties recommended that a photovoltaic panel's loss of energy upon conversion from DC power to AC at the inverter should be significantly higher than the 4% assumed in the filed Plan. Factors contributing to losses above 4% include, according to the Joint Solar Parties, shading and soiling; cell temperature; module output; wiring and mismatch losses; and inexact tracking of the maximum power point. The Joint Solar Parties recommended changing the AC-DC conversion loss factor from 4% to 25%.[16] The Agency agreed[17] to this proposed change, and that change was adopted in the Proposed Order.[18] The Agency has implemented this change in the Input Assumptions tab of the pricing model spreadsheets.

Capacity Factors

In the filed Plan and its Appendices, the capacity factors were assumed to be 17% for both distributed generation solar systems and community solar systems.[19] In response to comments by the Joint Solar Parties,[20] and based on data provided by the Solar Energy Industries Association, the Agency agreed[21] to update the pricing model to use a 14% DC capacity factor for distributed generation (presumed to be rooftop) solar projects and a 15.5% DC capacity factor for community solar systems (presumed to be ground mount, fixed tilt). These capacity factors are applied to the DC-rated capacity of systems.[22] The Proposed Order likewise adopted this change.[23]

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[14] JSP Objections at 33-34.

[15] IPA Response at 49-50.

[16] JSP Response at 31.

[17] IPA Response at 48.

[18] Proposed Order at 72.

[19] See Appendices E-1 and E-2, CREST Inputs worksheet, cell G12; Plan at 122.

[20] JSP Objections at 31-33.

[21] IPA Response at 49.

[22] Although the Plan stated that 17% was based on an AC rating, the filed Appendices E-1 to E-5 mechanically applied the 17% capacity factor to the DC equivalent of AC-rated project sizes (e.g., the Appendices multiplied 17% by 2,083 kW by 8,760 hours to determine the annual output of a facility rated at 2,000 kW AC), implying that 17% was being treated as a DC-rated capacity factor. See "CREST Inputs" tab at rows 8-13. This mismatch has now been corrected; the capacity factors are unequivocally stated with reference to DC ratings.

[23] Proposed Order at 72.

Transmission Rates
The Agency's previously-agreed change to the ComEd transmission rate for commercial and industrial customers with distributed generation projects is discussed above under "Changes to Utility Rates." The Proposed Order likewise adopted this change.[24]

Small Subscriber Adders for Low-Income Community Solar
The Agency agreed[25] in its Response to a proposal made in the joint Objections of Elevate Energy and GRID Alternatives, Inc. ("Elevate-GRID") that the Small Subscriber Adders for certain levels of small subscriber participation, used in the Plan's basic community solar REC pricing model, be also applied to REC prices in the Illinois Solar for All Low-Income Community Solar Project Initiative subprogram.[26] These adders have been incorporated in Appendix E-4. The Proposed Order likewise adopted this change.[27]

Assumed Savings from Net Metering for Low-Income Distributed Generation
The three Illinois Solar for All Program pricing models in the Plan assumed that customers with distributed generation, or community solar subscribers, would receive 50% of the resulting net metering savings. Elevate-GRID proposed increasing this assumption to 100% for residential participants (1-4 unit property owners) in the Illinois Solar for All Low-Income Distributed Generation Incentive subprogram and Low-Income Community Solar Project Initiative subprogram. The Agency agreed to this change but *only* for the Low-Income Distributed Generation Incentive subprogram (*not* for the Low-Income Community Solar Project Initiative subprogram).[28] Appendix E-3 has been updated to two new versions: Appendix E-3-a for the Low-Income Distributed Generation Incentive Program for buildings 5 units and larger, with 50% net metering savings assumed, and Appendix E-3-b for the Low-Income Distributed Generation Program Incentive for 1-4 unit buildings, with 100% net metering savings assumed. The Proposed Order adopted this change.[29]

Additional Changes to REC Pricing Model

Discount Rate
In the filed Plan and Appendices E-1 to E-5, the discount rate used on the Dashboard tab for calculating the 25-year net present values of project costs and net metering revenues was the same as the interest rate on term debt (cell G53 of the CREST Inputs tab). The Agency has determined that the weighted average cost of capital, which is found at cell G63 of the CREST Inputs tab, is a better discount rate to use for this purpose, as the REC pricing model

[24] Id.

[25] IPA Response at 94-95.

[26] Elevate-GRID Objections at 8.

[27] Proposed Order at 153.

[28] IPA Response at 96-97.

[29] Proposed Order at 153.

is essentially based on a discounted cash flow calculation.[30] This change has been made in applicable formulae on the Dashboard tab.

Assumed Project Costs in DC Ratings

The assumed cost data stated in Appendix D[31] to the filed Plan, as well as in the "Input Assumptions" tab of each of the filed Appendices E-1 to E-5, are from a NREL study[32] that quoted 2017 project costs based on DC-rated sizes. For example, the NREL study states that a 1,000 kW DC photovoltaic system has a total installation cost of $1.74 per watt DC, or $1,740,000 for the 1,000 kW DC system, which implies $3,780,000 for a 2,000 kW DC system. However, as the Joint Solar Parties stated, "[f]or a 2MW AC system, a 25% loss factor means that 2.667 MW DC must be installed to achieve a 2 MW AC output" – so, according to the JSPs, the assumed cost of a 2 MW DC system, taken directly from the NREL study, must be scaled up by 33% in order to calculate an assumed cost for a 2 MW **AC** system.[33] The Agency agrees with this critique and has implemented this change in the "Input Assumptions" tab of the pricing model spreadsheets.

Smart Inverter Rebate Calculation

Certain mechanical formulas in cells G69 and Q46 of the CREST Inputs tab were adjusted to avoid a calculation error that was limiting the value of the assumed smart inverter rebate for non-residential distributed generation and community solar projects under Section 16-107.6 of the Public Utilities Act.[34]

Community Solar Property Tax Calculation

In the Community Solar pricing models (filed Appendices E-2 and E-4), where the annual property tax is calculated at cell G39 of the CREST Inputs tab, the formula in the prior models incorrectly included the AC-DC conversion factor. Inclusion of that factor is not necessary (as the formula is intended to multiply an assumed property tax rate[35] per kW AC by the system size in kW AC), and this error has now been corrected.

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[30] See, e.g., https://www.wallstreetoasis.com/finance-dictionary/what-is-weighted-average-cost-of-capital-WACC.

[31] Plan Appendix D at 8, Table D-6.

[32] See https://www.nrel.gov/docs/fy17osti/68925.pdf at 29.

[33] JSP Reply at 23-24.

[34] 220 ILCS 5/16-107.6.

[35] In its filed Plan and Appendices, the Agency adopted the figure of $6,000 of annual property tax per MW AC, as proposed by the Joint Solar Parties in their Comments to the Draft Plan (page 6).

Additional Roll-Forward of Cost Declines

The filed Plan and Appendices assumed project construction would begin in 2018, so the previous version of the REC pricing model reduced the 2017 NREL cost data by 4% (the assumed annual reduction in installation cost). The Agency's updated model, in the Input Assumptions tab of each spreadsheet, now reduces assumed installation costs by an additional 4%, based on an assumption that project construction will begin in 2019, following the opening of the Adjustable Block Program in late 2018.