ILLINOIS POWER AGENCY

Illinois Power Agency
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Stakeholder Feedback Request for the 2024 IPA Long-Term Plan

Renewable Energy Credit Price Calculation Methodology for Illinois Shines and Illinois Solar for All

June 8, 2023

In the 2022 Long-Term Plan, the Agency committed to "engage an independent expert consultant to complete a thorough review of REC prices prior to the next update of the Agency's Long-Term Plan. The independent expert consultant will provide the IPA with recommendations on how to develop administratively-set REC prices that both efficiently invest ratepayer funds in renewables and respond annually to changing market conditions. The IPA will provide transparency around the results of the review and utilize the independent analysis to craft REC prices for the next Plan."[1]

The Agency engaged Sustainable Energy Advantage, LLC ("SEA") to conduct this independent review of the REC pricing approach for the Illinois Shines and ILSFA programs. The process included initial presentations and requests for stakeholder feedback.[2] The report, found on the Stakeholder Engagement section of the IPA website, is being used by the Agency to update the REC pricing methodology for the 2024 Long-Term Plan, and the Agency is interested in stakeholder feedback on specific recommendations contained in the report (and excerpted below) as well as several additional topics. Stakeholders are invited to comment on as many of the following items as they would like and may provide comments beyond the scope of these specific questions. Responses will be published on the IPA website under the "Plans Under Development" section of the Procurement Plans page. A draft of the plan will be released for public comment on August 15, 2023.

Please note that the Illinois Power Agency is exploring many ideas and points of view as it considers how to improve its programs, procurements, and operations. The inclusion of an idea or question does not necessarily imply that the IPA intends to take a specific approach in the upcoming Long-Term Plan or otherwise.

How to Reply

Please provide comments via email attachment to IPA.ContactUs@Illinois.gov with the subject "[Responder's Name] – REC Pricing LTP Feedback" by June 29, 2023.

Topics

1. Cost-Based Annual Incentive-Setting
2. Project-Level Data

[1] See: https://ipa.illinois.gov/content/dam/soi/en/web/ipa/documents/modified-2022-long-term-plan-upon-reopening-9-may-2022-final.pdf at 184.

[2] See: https://ipa.illinois.gov/renewable-resources/stakeholder-engagement.html under "Illinois Shines (Adjustable Block Program) and Illinois Solar For All REC Prices Updates"

3. Billing Determinant-Level Net-Metering Credit Forecast
4. Criteria Around Deployment-Based Adjustment to Annual Cost-Based Pricing Estimate
5. IRA Implementation
6. Community Solar Customer Acquisition and Maintenance Costs

TOPIC 1: SEA Recommendations 1 and 2: Continue to use the Cost-Based Approach to Annual Incentive-Setting

Background

Excerpt from Recommendation 1:
"ABP and ILSFA require a high degree of incentive differentiation by project type. The cost-based approach also supports Illinois' desire to create a long-term, stable solar industry within the state by providing price signals on an annual basis and transparency into—plus the opportunity to participate in, the price-setting process. This review recommends the continued use of a cost-based approach, with REC prices reset each year."

Excerpt from Recommendation 2:
"This independent review concludes that a DCF model is the preferred tool for calculating the revenue requirement for each ABP and ILSFA project category. Recovery factor analyses are not sufficiently precise, particularly with respect to their treatment of tax benefits, which regularly comprise 50% (or more) of renewable energy project value on an NPV basis."

Question

1. Based on this recommendation, the Agency is planning to continue to use the CREST model developed by the National Renewable Energy Laboratory as the core of the approach for determining REC prices. In particular, the Agency values the transparency that using CREST provides stakeholders. Do you have any concerns with the continued use of the CREST model, or have a proposal for different cost-based model to be utilized?

TOPIC 2: SEA Recommendation 3: Collect and Disclose Project-Level Data, Aligned to CREST Input Fields

Background

Excerpt from Recommendation 3:
"Cost-based incentive programs are intended to enable project sponsors to cover all operating expenses and earn a risk-adjusted return on their initial investment. As a result, specific and verifiable project-level cost data are critical to the effective implementation of cost-based programs. Without these data, policymakers lack visibility into how average project costs (and cost components) are changing over time….

The ABP's Part II application currently requires information disclosure. A list of 21 items can be found on pages 97 and 98 of the October 18, 2022 ABP/Illinois Shines Program Guidebook. Only the final question relates to the applicant's obligation to report cost data. This question demonstrates policymaker intent that cost data should be collected. The question is not sufficiently precise, however, to result in the collection of comparable and actionable data. Rather than requesting "any and all costs related to the following" (which will result in responses that are impossible to interpret and compare), this single question should be divided into multiple questions, each requiring data aligned to the input categories in the CREST model. This should apply to both development and installation costs and all operating expenses. When aggregated, the sum of these costs and expenses should be all inclusive.

Data aligning with CREST input categories should be disclosed to the entity running the stakeholder feedback and CREST modeling process. Appropriate steps may be taken to ensure that the entity operating the CREST model does not disclose component-level data for specific projects. It is important, however, that individual project cost category data be collected to inform the CREST modeling process.

Questions

1. For entities that operate in other states where project cost data is collected by state incentive programs, are there states that have best practices in terms of standardization of data collection that Illinois should look to?
2. Would having a standardized/line-item form to fill out component level equipment costs be preferred, or are there other self-report industry standard categories regarding equipment costs that could be used? The CREST Model uses the following Capital Cost line items that cost information would need to be aggregated into:
    a. Generation Equipment
    b. Balance of Plant
    c. Interconnection
    d. Development Costs & Fee
    e. Reserves & Financing Costs
3. Implementing new data collection processes for project costs will take time before data is available. The current REC Pricing Model uses national data from NREL benchmarking reports. For the 2024-2025 Program Year, are there adjustments to the national data from NREL that should be considered as proxies until such time as Illinois-specific data is available?
4. The current model assumes a 45% debt/equity ratio, and a target 12% after-tax internal rate of return for distributed generation and a 14% after-tax internal rate of return for community solar (with Illinois Solar for All residential projects having a 0% debt/equity ratio due to the requirement to not have up-front costs for the participant). These levels were established via stakeholder

feedback during the development of the first Long-Term Plan in 2017-2018. Are these levels still appropriate reflections of current and expected market conditions?[3]

5. The current REC Pricing Model uses capacity factors based on averages of Illinois Shines projects submitted. Should this approach be maintained, or should the model use assumptions based on the capacity factor for an optimally designed system?
6. Interconnection costs can vary greatly, especially for community solar projects. What would be reasonable ranges of per kW interconnection costs by project category?

TOPIC 3: Recommendation 4: Perform and Deploy a Billing Determinant-Level Net Metering Credit Forecast

Background

Excerpt from Recommendation 4:
"For background, a billing determinant is a specific portion of customer rates (typically parceled out in the form of dollars or cents per kilowatt-hour (kWh) for energy-based charges, dollars or cents per kilowatt (kW) demand for demand-based charges, or dollars per customer per month for per-customer charges). Note, however, that this recommendation has a prerequisite. Before considering a billing determinant-level net metering credit forecast, the parties should come to a common understanding of which utility rate components are included in the net metering credit for each applicable customer and project type."

Questions

1. With recent changes to net metering tariffs, please provide your understanding of the billing determinants that should be used net metering for any or all of (1) residential customers receiving retail rate net metering, (2) customers receiving supply-only net metering, and (3) community solar net metering. If you provide specific bill examples, please redact any personal identifiable information such as account numbers, meter numbers, customer names, or street addresses.
2. The current REC pricing model assigns 20% of the value of net metering to the customer as savings and 80% to cover the residual cost of the system for Illinois Shines. For Illinois Solar for All 1-4 unit residential projects 100% of the savings is assigned to customer savings, and for 5+ unit buildings and low-income community solar 50% of the savings. Should these ratios be updated, or do they accurately reflect current market offers?
3. The current REC Pricing model uses an assumption of a 1% annual inflation rate for the value of net metering credit. To calculate the discount rate using the net present value of the residual value of net metering credits over the term of the REC delivery contract (using the weighted cost of capital generated by the CREST model). Are there other approaches that could be considered for estimating the net metering value in the REC pricing model?

3 See also Appendix A of the SEA Report for additional discussion of considerations related to rates of return.

TOPIC 4: Recommendation 5: Establish and Implement Criteria for a Deployment-Based Adjustment to Annual Cost-Based Pricing Estimates

Background

Excerpt from Recommendation 5:
"Per Recommendation 1, we advise continuing to recalculate REC prices annually. In addition, we recommend policymakers consider the potential benefits of allowing a post-processing adjustment (i.e., an adjustment to the REC price after the initial, annual calculation has been made) based on the level of program participation in the prior year. Participation would be defined by the total capacity associated with applications received in a given program year and measured on a category-specific basis. For an adjustment to occur, participation would need to fall either above or below a threshold relative to the annual category-specific target. This recommendation is intended to fulfill stakeholders' request for inclusion of a market-based mechanism within the REC price setting process....

"SEA recommends that if 75% to 150% of the target capacity is enrolled, then no adjustment would occur. Thus, in a year in which a given category was fully enrolled and had a waitlist equal to another 49% of block capacity, the REC pricing would nonetheless be considered as still remaining within a reasonable range, and would not be subject to adjustment. On the other hand, if the waitlist represents many multiples (e.g., 300% or 400%) of the block allocation, then the following year's REC price would be adjusted downward on the assumption that there are more than enough cost-effective projects to fulfill program objectives at a slightly lower REC price. Table 5 summarizes the recommended year-to-year REC price adjustments and associated market conditions, as applicable to all ABP and ILSFA categories."

Table 5: Recommended Year-to-Year REC Price Adjustments and Associated Market Conditions

Market Condition	Recommended Price Adjustment
<25% of block capacity has been awarded at end of prior program year	Cost-based REC price for the following year is automatically increased by 10% of the block-specific revenue requirement
25% to <50% of block capacity has been awarded at end of prior program year	Cost-based REC price for the following year is automatically increased by 7.5% of the block-specific revenue requirement
50% to 75% of block capacity has been awarded at end of prior program year	Cost-based REC price for the following year is automatically increased by 5% of the block-specific revenue requirement
>75% to 100% of block capacity has been awarded at end of prior program year	No REC price adjustment
If "Waitlisted Capacity" is 50% to 100% on top of the Program Year Block Size	Cost-based REC price for the following year is automatically decreased by 5% of the block-specific revenue requirement

If “Waitlisted Capacity” is >100% on top of Program Year Block Size	Cost-based REC price for the following year is automatically decreased by 10% of the block-specific revenue requirement

Of equal importance is the methodology for making the adjustment itself. This review discusses two possible approaches – the revenue requirement approach and the REC price approach. In the revenue requirement approach, the REC price would be adjusted as a percentage of the project’s total levelized cost of energy (LCOE). This approach provides a direct link between the cost of the project and the REC price. For example, if the category specific LCOE was modeled at $150/MWh and the initial calculated REC price was $40, then if 60% of the prior year block was filled there would be a positive adjustment of $7.50/MWh (i.e., 5% of the LCOE). Under this set of conditions, the adjusted REC price for the following program year would be $47.50.

In the REC price approach, the triggering parameters and adjustment factors would be the same, but the percentage change would be based on the calculated REC price rather than LCOE. This approach might be slightly simpler to explain, but it does not require any less analysis to execute. The REC price approach also dilutes the connection between the REC price adjustment and the assumed cost of the project. As a matter of design, the REC price approach will always result in smaller adjustments than the revenue requirement approach.

This review recommends the revenue requirement approach, to maintain a logical connection between the cost of the project and the REC price adjustment. If smaller adjustments are preferred, this can nonetheless be achieved within the revenue requirement approach by changing the adjustment percentages in Table 5 as part of the Long-Term Plan development process. It is worth repeating that as the accuracy of annual cost-based REC price setting improves, program enrollment will more closely align with block size and the need for year-to-year adjustments will decrease. In addition, this recommendation can be augmented to include policymaker review and stakeholder comment steps.”

<u>Questions</u>

1. Do you agree that there should be market-based condition REC price adjustments for each new program year in addition to annual updating of inputs into the REC Pricing Model?
2. Are the proposed market-based condition thresholds appropriate for triggering additional adjustments to REC price for a new program year?
3. Should there be an additional stakeholder process prior to making these adjustments, rather than having them automatically applied, and if so, what would be recommended considerations and process?

TOPIC 5: Adjustments to ABP/ILSFA in Response to Inflation Reduction Act of 2022

<u>Background</u>

Excerpt from Recommendation 6:
"Passage of the Inflation Reduction Act presents both opportunities and challenges for DG programs like ABP and ILSFA. Overall, the IRA should lower the after-tax levelized costs of DG projects, thereby increasing the cost-effectiveness of the ABP and ILSFA programs on a per MW basis. However, the new base/bonus structure for the ITC presents far more possible permutations of potential ITC percentage values than in program years prior to the IRA that can be claimed by a given project. These permutations present both methodological and policy questions for the implementation of cost-based programs like the ABP and ILSFA...... We [SEA] recommend that the IPA require modeling of at least some permutations of bonus ITC values for projects. We [SEA] believe that given the budget-based nature of the program, incorporating bonus credit values into modeled projects where appropriate would result in more deployed resources per dollar of incentive available, all other factors held equal."

"**Policy Alignment:** SEA recommends that the IPA, where possible, align program definitions and requirements with the eligibility criteria of relevant ITC bonuses. For instance, the domestic content sections of the IRA permit a business taxpayer to receive a bonus 10% of the absolute value of the ITC for meeting certain thresholds for the iron, steel, or other manufactured products in projects. If all DG projects are required to make good faith efforts to qualify for the bonus, up to the 25% cost cap, the bonus could be assumed for all projects without biasing results towards projects that do or do not qualify for the bonus. We note that further federal guidance on domestic content requirements is forthcoming, which may elucidate the incremental costs of the meeting the domestic content thresholds, and thus whether it would be economical for projects to claim, but we note this as an illustrative example."

<u>Questions</u>

1. Should the Agency include the bonus 10% domestic content adder to the ITC? If not, should some pro-rated amount be considered to reflect good faith efforts to harness this bonus?
2. Should Illinois Solar for All REC prices be adjusted to include accounting for some or all of the 20% "Low Income Economic Benefit" bonus and/or the 10% "Located in a Low-Income Community" bonus? If yes, should there be a shared benefit of these bonuses, for example incorporating 50% of the value into the REC Pricing Model, allowing the participant to retain a portion of the benefit.
3. The current REC Pricing Model for Non-Profit and Public Facilities assumes that those projects are not taxable entities and thus do not use the ITC or bonus depreciation. With the direct pay option allowing non-taxable entities to benefit from the ITC, this approach will require updating. Besides having higher values from net metering compared to Illinois Shines, and not having other tax benefits available (, are there other

TOPIC 6: Community Solar Subscriber Acquisition and Maintenance Costs

<u>Background</u>

The current REC Pricing Model includes a $14.82/REC adder to account for the costs associated with managing small subscribers. This value was the midpoint value derived from a 2018 GTM report on community solar costs (See Section 7.5.6 of the 2022 Long-Term Plan). The GTM Report provided a range between $0.18 and $0.60 per Watt and the Agency converted that into a value per REC. This value was also similar to a $15.00 adder used in Minnesota for projects energized in 2019 or 2020.

Questions

1. How have costs changed given the maturation of community solar over the past several years including the emergence of web-based subscription services? Can you cite or provide any more recent studies to support your observations? How will the new option for consolidating billing for community solar subscriptions, impact community solar subscription management costs?