REC Pricing Methodology

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

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?

JSP RESPONSE: The Joint Solar Parties support continuing to use the CREST model. As the Joint Solar Parties note in response to later questions, reliance on current and accurate data is of key importance and frequently industry data best meets those qualifications, including changing inflation numbers which are negatively impacting all segments of the solar industry.

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

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

JSP RESPONSE: As an initial matter, the Joint Solar Parties reject the premise of the following passage in the SEA report about verifiable project-level data: "Market participants should be aligned with this objective – especially in the context of an 'adjustable' block program that recognizes costs may go up or down from year to year as market conditions change – unless their strategy and expectation is that incentives will be set higher

than necessary in the absence of reliable data." Unfortunately, that passage also reflects the historic treatment of industry assessments and data that has been offered in informal comment and litigation for use in the CREST model.

Responding further, the Joint Solar Parties do not object to continuing to provide data by category in the Part II applications corresponding with CREST categorization. While not all Approved Vendors filling out Part II applications have overall development costs (because they purchased the project and do not know what it cost), development fees are a reasonable proxy for the costs in the market of those services. There is no need for more granular data because it is not analyzed by the CREST model.

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?

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?

JSP RESPONSE: The Joint Solar Parties respectfully recommend that given SEA's forceful recommendation against data other than historic averages, the Joint Solar Parties do not recommend deviation.

6.Interconnection costs can vary greatly, especially for community solar projects. What would be reasonable ranges of per kW interconnection costs by project category?

JSP RESPONSE: The Joint Solar Parties suspect that interconnection costs will continue to vary wildly. The Joint Solar Parties have historically supported using historic averages and given SEA's forceful recommendation against data other than historic averages, the Joint Solar Parties do not recommend deviation.

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

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.

JSP RESPONSE:

For behind-the-meter net metering, the billing determinates depend on the supplier, rate structure, and customer size. For illustrative purposes, the following assumes utility supply:

- **For subtype (d) customers (residential customers on non-TOU rates): the net metering credit rate is the sum of all per kilowatt-hour charges/credits on the entire utility bill multiplied by the kilowatt-hours of net generation. The credits can be expressed as dollars or kilowatt-hours.**
- **For subtype (d-5) customers (residential customers on TOU rates): the charge or credit is the volumetric charge during each interval multiplied by the net export or import during that interval, with those intervals aggregated over the entire billing cycle.**
- **For subtype (e) customers (non-residential customers that have not been declared competitive but that bill delivery on a kW and not kWh basis): These are supply-only net metering customers. Their supply rate is multiplied by the net export over the billing cycle.**
- **For subtype (f) customers (all customers in competitively-declared classes), these are supply-only net metering customers. Much like (d-5) customers, the charge or credit is the volumetric charge during each interval multiplied by the net export or import during that interval, with those intervals aggregated over the entire billing cycle.**

For (d) and (e) customers, the supply rate is the Price to Compare, which has a volumetric energy and capacity charge, a volumetric transmission charge, and the PEA. For (d-5) and (f) customers on utility supply, there is an hourly-changing volumetric energy charge, a capacity charge (volumetric in Ameren, demand-based in ComEd), and a volumetric transmission charge, plus a PEA applicable to hourly customers.

Note that following the 2024-25 delivery year, full retail net metering even for residential customers will become vanishingly rare for new systems pursuant to Section 16-107.5(j). In subsequent delivery years, all systems should assume that there is no delivery-side net metering.

Community solar net metering is relatively straightforward: once Ameren Rider NMCS is in effect (as stipulated in ICC Docket No. 22-0208), all community solar bill credits will be equal to: (1) the Price to Compare (which is the purchased electricity charge—energy and capacity—the transmission charge (Ameren Rider TS or ComEd's PJM Services Charge)) plus the Purchased Electricity Adjustment; multiplied by (2) the kilowatt-hours associated with the subscription. The applicable Price to Compare is the DS-1 rate for all residential customers in Ameren and the applicable DS-2 rate for all other customers in Ameren; it is the residential rate or applicable non-residential rate (including watt-hour) for ComEd.

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?

JSP RESPONSE: In the behind-the-meter market, customer retained value is not tied by formula to the net metering credit—due in large part to the challenges calculating the customer's exact savings (especially on time-variant rates and due to the effect of demand-based charges). However, those percentages are reasonable approximations of customer retained value.

For community solar, the dominant product appears to be a charge based on the actual bill credit—which is far more transparent and straightforward to bill against. While the Joint Solar Parties are not sure 20% savings reflects a typical product or the average of all products, it appears to be a reasonable expectation.

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?

JSP RESPONSE: The Joint Solar Parties believe 1% is more reasonable than a higher percentage, but it is challenging to precisely model net metering credit values because the energy markets that drive retail pricing have so much internal noise that a simple compounding increase cannot accurately model most shorter-term windows (at least in Illinois since 2011).

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

Questions

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?

JSP RESPONSE: As an initial matter, Section 1-75(c)(1)(K) requires that "the Adjustable Block program shall provide a transparent annual schedule of prices and quantities to enable the photovoltaic market to scale up and for renewable energy credit prices to adjust at a predictable rate over time." Introducing a whiplash effect from cost-based and "market-based" alterations would not be a predictable rate over time.

Second, the use of the term "revenue requirement" by SEA is confusing. While the CREST model is cost-based, solar development is very different from the typical utility development approach. Utilities do not have to try to develop ten transformers in order to get five through fatal flaw analysis and three into an incentive program—they simply build and receive recovery of reasonable and prudent costs with a rate of return. Developers continue to take risks—risks that are not directly recognized in the CREST model because they are related to projects that are not built rather than those that are.

Third, the adjustments are not actually market-based but simply an arbitrary adjustment in response to demand. Actual market-based adjustments would focus on updated costs and revenues—but NREL data (the exclusive data set other than historic Part II costs, because the IPA has consistently rejected industry studies) moves far slower than the market. Even if the arbitrary adjustments are directionally correct, they are crude attempts at adjustment rather than responses to actual market conditions. As explained in response to Question 3 below, a better approach is to allow use of industry data with a case-by-case review of questions or concerns about methodology.

Frequently, marketing and development decisions take a multi-year view and thus benefit from stability and predictability of REC prices. Conversely, unpredictable REC price adjustments would create sizable risks for all manner of participants in the solar industry (including customers) that are dependent on the predictable forecasting of REC values. Predictability is critical to any incentive program, and to any market. No other program to the Joint Solar Parties' knowledge uses such mechanisms.

2. Are the proposed market-based condition thresholds appropriate for triggering additional adjustments to REC price for a new program year?

JSP RESPONSE: No. Please see above.

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?

JSP RESPONSE: It is unclear what data the IPA would rely on in such an instance given SEA's characterization of anything other than actual historic data as industry attempts at manipulation (which industry participants will understandably be reluctant to provide anyway in a request for comments) or government studies, which will far lag the market. Respectfully, industry data tends to be the most current and accurate data—the IPA could address questions or concerns with study methodology on a case-by-case basis—and thus categorically ignoring industry data means there will likely be a lag before the IPA successfully identifies trends in the market.

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

Questions

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?

JSP RESPONSE: As an initial matter, the Joint Solar Parties are unsure how SEA believes that federal guidance will "elucidate the incremental costs of the [sic] meeting the domestic content thresholds" given that federal guidance is either not final or doesn't apply and the guidance itself is not firm pricing with a guaranteed delivery term for specific equipment.

Specifically, the domestic content adder cannot be counted on based the current regulatory state. The domestic content requirements have largely been criticized as non-administrable

due to increased difficulty and confusion in qualifying - mainly because the developer claims the credit, but has to rely on manufacturers to certify what percentage of the cost of their product was manufactured in the USA, and developers must know the cost stack of ALL components. Industry is recommending additional changes to the guidance to ensure a clear, achievable path for manufactured products to meet domestic content thresholds for bonus credit eligibility. Currently, in order to be considered a "US manufactured product," 100% of the product's direct labor and materials need to be of U.S. origin. The cost of U.S. labor in transforming foreign manufactured product components to project components manufactured products (for use in U.S. projects) is not counted towards the domestic content cost percentage. And, in order to support a claim for the domestic content bonus credit, project developers must solicit highly sensitive cost and component origin information from manufacturers. (*See* https://www.projectfinance.law/publications/2023/may/domestic-content-bonus-credit/).

Responding further, the member companies of the trade associations that comprise the Joint Solar Parties continue to evaluate on an entity-by-entity basis whether domestic content pricing and availability (or in many cases projected pricing and availability) is sufficient to meet requirements for ABP or SFA projects. At this time, it is premature to assume that all or even any projects are capable of meeting the domestic content guidelines. In addition to the challenging implementation, the industry is concerned about having a clear sightline to when qualifying domestic content products will be widely available. Currently, there is a limited supply of solar modules manufactured in the US. Availability of US-made modules is expected to ramp up as manufacturers build out production capacity between now and 2026, but the module components supply chain will also need to ramp up quickly if US-made modules are to qualify as domestically manufactured product. In the future, The IPA should evaluate based on actual Part II applications whether the domestic content adder is prevalent. If there becomes a time where domestic content that qualifies for the IRA adder is prevalent, it would be more appropriate for the REC pricing model to be adjusted.

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.

JSP RESPONSE: No. Guidance just recently came out for energy communities and low-income benefits. The member companies of the trade associations that comprise the Joint Solar Parties continue to evaluate the guidance and have yet to make it to Part II on a statistically significant enough scale to support IPA research into actual practices.

LMI ITC Bonus Credit: According to initial guidance, this adder will be capped (1.8 GW/year) and allocated, with a confusing and complicated application/discretionary selection process, that won't even open until sometime in the third quarter of 2023, and after that for residential projects. This means there is no guarantee that any of these funds will go to Illinois customers or the types of projects incentivized in Solar for All. It is likely that this adder will result in zero projects built during the 2023-24 delivery year. It is premature to assume the LMI Bonus Credit will be widely available to Illinois Solar for All systems until

the selection process is finalized and open and there is some experience. At best, the IPA should consider revisiting this prior to setting pricing for the 2024-25 delivery year (assuming some additional actionable data is available).

Energy Communities Bonus Credit: The U.S. Department of Treasury has issued initial guidance, but until it promulgates formal regulations, investors and financing parties may not finance the Energy Community Bonus Credit, so it is too early to consider making changes to ILSFA or ABP incentive levels in these areas. Additionally, after rules are final, the Joint Solar Parties encourage the IPA to consider the administrative challenges in setting a single price when Energy Communities are in limited locatiosn within the State. In addition, if incentives are limited with a 1:1 reduction on funding, developers are likely going to be discouraged from taking on the risk for limited return (because for third-party financing typical owner/operators only earn 75-80 cents on the dollar of tax value) Illinois would be negating or even discouraging the benefit intended by federal government.

TOPIC 6: Community Solar Subscriber Acquisition and Maintenance Costs

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?

JSP RESPONSE: If anything, acquisition costs have tended to go up as the market becomes more competitive and more customers now have subscriptions. In addition, compliance costs for consumer protections related to marketing, solicitation, and the standard disclosure form have been at minimum flat if not increasing. The net billing approach from the utilities is expensive (2% of bill credit value for ComEd; yet to be disclosed for Ameren) and introduces substantial non-payment risk if a customer short-pays and thus is not expected to displace most existing solutions. The Joint Solar Parties recommend no further changes other than for inflation.