Independent Review of Illinois Shines and Illinois Solar for All Renewable Energy Credit Pricing Approach

Prepared for:

Illinois Power Agency

Prepared by:

Sustainable Energy Advantage, LLC

161 Worcester Rd, Suite 503

Framingham, MA 01701

www.seadvantage.com

508.665.5850

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Notice and Acknowledgements

This whitepaper was prepared by Sustainable Energy Advantage, LLC (SEA) on behalf of the Illinois Power Agency (IPA). The opinions expressed herein do not necessarily reflect those of the IPA or the State of Illinois, and reference to any specific process, method, or policy recommendation does not constitute an implied or expressed endorsement.

SEA appreciates the opportunity to have conducted this independent review of Illinois Shines and Illinois Solar for All REC pricing approaches. SEA acknowledges and appreciates the support of IPA staff (Anthony Star, Hannah McCorry, Adam Groner, and Kelly Turner) and NERA Economic Consulting (Benjamin Chee) throughout the scoping, research, and stakeholder engagement process. .

Sustainable Energy Advantage, LLC Contributing Authors

Jason Gifford

Cal Brown

Jim Kennerly

Andrew Lidington

With Research and Analytical Support from:

Tom Michelman

Tobin Armstrong

Witter Swanson

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Introduction

The Illinois Power Agency (IPA) retained Sustainable Energy Advantage, LLC (SEA) to conduct an independent review of Renewable Energy Credit (REC) pricing policy for the state's Illinois Shines and Illinois Solar for All programs. The IPA resolved in the proceedings of Docket 222-0231 on the 2022 Long-Term Renewable Resources Procurement Plan (the Long-Term Plan) to engage a third-party expert to provide "recommendations on how to develop administratively set REC prices that both efficiently invest ratepayer funds in renewables and respond annually to changing market conditions."[1]

In developing this Whitepaper, SEA reviewed the relevant statutes, administrative records, and program outcomes, and relied upon its experience working in other jurisdictions on distributed generation and REC pricing policy design over the last 25 years. Using these sources and expertise, SEA developed and presented an overview of the historical development of Illinois' distributed generation policies, provided a framework for assessing REC pricing design options and implications, and provided an initial set of recommendations to stakeholders in March 2023. SEA's two presentations ("Illinois ABP and SFA REC Pricing Policy Design Issues, Options, and Implications" and "Key Inflation Reduction Act Changes Relevant to ABP and SFA-Eligible Projects" can be found on the Illinois Power Agency website. SEA solicited feedback from program stakeholders in written and oral form, and then developed the instant Whitepaper for consideration by the Illinois Power Agency and stakeholders during the development of the 2024 Long-Term Plan.

Executive Summary

Context

The Illinois' distributed generation incentive programs, Illinois Shines (formerly known as the Adjustable Block Program or ABP) and Illinois Solar for All (ILSFA), were created in 2017 with the goals of supporting statewide solar deployment, promoting market growth and stability across multiple, specified segments. The Illinois Solar for All program has the additional goal of supporting the market for low-income and environmental justice communities. Both ABP and ILSFA offer REC incentive prices to supplement the net metering revenue earned by solar projects, with REC prices intended to cover project costs plus a risk-adjusted rate of return (which we describe more in Appendix A) for a modeled proxy project in each program category. To provide additional support, further reduce risk, and enable cost-effective financing, REC payments (for many, but not all, projects) are front-loaded relative to the REC delivery term. . These programs were revised by the Climate and Equitable Jobs Act of 2021 but remain cost-based incentive programs. The annual program year runs June 1st through May 31. st. The recommendations herein will be considered as part of the next Long-Term Plan, for implementation during the 2024 – 2025 program year.

REC Pricing Design Options

REC pricing policy design should be guided by the question "what are we trying to accomplish." That is, what are policymakers' objectives, and how are they prioritized? For example, some states' programs prioritize least-cost procurement on behalf of ratepayers, while others value rapid deployment of renewable energy megawatts, which often necessitates higher incentive levels. Many states have objectives to foster a diversity of resource types and offtakers, with program capacity reserved for specified market segments and prices set accordingly. ABP and ILSFA most closely align with this latter approach. Ultimately, the objective is to balance market development and stability with ratepayer cost.

Common structures for distributed generation incentives are summarized below:

- **Market-based programs** set demand targets (either on a stand-alone basis or via carve-outs for specified resources within state Renewable Portfolio Standards) and permit supply and demand forces to set prices, typically subject to price caps.
- **Value-Based programs** compensate distributed generation for avoided costs to the grid and society, which inherently varies by project size, interconnection type, location, production profile, and other characteristics.
- **Cost-Based programs**, including the Illinois distributed generation programs, compensate market participants based on estimates of participating projects' total installed costs and operating expenses, and set incentives with the intent to provide a risk-adjusted rate of return.
- **Hybrid approaches** mix-and-match the programmatic approaches summarized above, such as a cost-based REC incentive paired with adders or subtractors based upon offtake and siting characteristics, to produce desired policy outcomes.

REC Pricing Policy Recommendations

REC pricing policy recommendations – including structure, methodology, and adjustments – are summarized in Table ES-1, below. . The implications of P.L. 117-169 – Inflation Reduction Act of 2022 (hereafter referred to as the Inflation Reduction Act or "IRA") are summarized in Table ES-2. This Whitepaper is structured to first convey the context and rationale for these recommendations, and then provide an explanation for the recommendations themselves.

Table ES-1: Summary of REC Pricing Policy Design Recommendations

Recommendation	Objective	Implementation
1. Continue to use the Cost-Based Approach to Annual Incentive-Setting	Incentives differentiated by project type; transparency; stability	Detailed cost research and stakeholder input
2. Continue to use a Discounted Cash Flow model to calculate the revenue requirement for each ABP and ILSFA project category	Accurate accounting for tax incentives; transparency;	Incentives set annually via CREST modeling
3. Collect and Disclose Project-Level Data, Aligned to CREST Input Fields	Balance risk-adjusted returns and ratepayer impact	Annual collection and disclosure process
4. Perform and Deploy a Billing Determinant-Level Net Metering Credit Forecast	Estimate net metering credits based on market drivers	Identify and forecast specific billing determinants from tariff
5. Establish and Implement Criteria for a Deployment-Based Adjustment to Annual Cost-Based Pricing Estimates	Account for non-price factors; market-responsive	Adjust REC price relative to deployment thresholds
6. Refrain from Intra-Year Adjustments to REC Price Incentives	Discourage price manipulation	Annual adjustments

The Inflation Reduction Act (IRA) updated the rate, duration, and eligibility criteria for renewable energy tax credit incentives. . The IRA restored the ITC to its original 30% level, extended this benefit through 2032 using a new Clean Energy Investment Credit (CEIC), allowed transferability (subject to constraints), and created several 'bonus' credits for projects meeting certain component, labor, locational, or other criteria. . Considered all together, these advancements are expected to reduce the after-tax levelized cost of energy for projects participating in the ABP and ILSFA.

Table ES-2: Recommendations to Align ABP/ILSFA with Inflation Reduction Act of 2022

Recommendation	Objective	Implementation
1. Include interconnection costs in ITC basis (for non-residential projects) where allowed by IRA	Update REC price calculation to account for new Federal incentives	Ensure CREST is programmed to include interconnection costs in the calculation of ITC/CEIC value, where applicable
2. For ABP, model REC prices not only with 30% ITC, but also assuming one bonus credit (i.e., total 40% ITC)	Update REC price calculation to account for new Federal incentives	Calculate REC incentive based on LCOE with revised ITCs
3. For ILSFA, model REC prices not only with 30% ITC, but also assuming the "low-income economic benefits" bonus credit (i.e., total 50% ITC)	Update REC price calculation to account for new Federal incentives	Calculate REC incentive based on LCOE with revised ITCs
4. Align ABP and ILSFA programmatic requirements and definitions with IRA bonus credit requirements	Simplify administration of ABP and ILSFA projects and maximize their share of federal funding (thus enhancing the cost-effectiveness of both programs)	(As one example…) Update definitions of low-income customers to "low-income communities," or potentially adopt other definitions related to "energy communities"
5. Create project sub-classes/sub-categories (and differential REC prices) for projects eligible to receive bonus credits in existing ILSFA and ABP project categories	Ensure that projects receiving bonus credits are not double-compensated (e.g., receiving a REC price developed with an assumption the project will receive no bonus credit, while simultaneously claiming a bonus credit)	(1) Require project owners to formally attest to bonus credits taken or not taken. (2) The IPA's planning consultant could identify and model the most common categories expected to claim bonus credits and model differentiated REC prices that account for all associated incremental capital and operating costs.

In addition to these specific recommendations for the 2024 – 2025 program year, this whitepaper includes several topics for longer-term consideration, and which are expected to require expanded legislative authority. . The ‘Longer-Term Legislative Consideration’ section discusses the potential benefits to both ratepayers and projects of approaches in which incentives are tied to a project’s total revenue requirement. Overall, this REC pricing policy review seeks to spur a dialogue between policymakers and market participants and explore new policy mechanisms that balance the interest of Illinois ratepayers and the renewable energy development community. .

Program History and Current REC pricing approach

FEJA creates Adjustable Block Program and Illinois Solar for All

The 2017 Future Energy Jobs Act, Public Act 99-0906 (FEJA) created the Adjustable Block Program (ABP) and the Illinois Solar for All Program (ILSFA). The ABP is a solar incentive program that supports the development of new photovoltaic (PV) distributed generation (DG) and community solar projects in Illinois through payments for renewable energy credits (RECs).[2] ILSFA aims to boost participation in solar energy projects serving income-eligible and environmental justice communities; programs include residential solar, community solar, and solar for nonprofits and public agencies.[3] ILSFA incentives are also delivered through REC purchases.

Program History: Adjustable Block Program

The goal of the ABP program is to provide for the "steady, predictable, and sustainable" growth of new solar PV development in diverse locations throughout Illinois.[4] The ABP provides a transparent annual schedule of prices and quantities, enabling the PV market to scale up, and for renewable energy credit (REC) prices to adjust at a predictable rate over time. The ABP is "designed to ensure that RECs are procured from PV distributed renewable energy generation devices and new PV community renewable energy generation projects in diverse locations throughout the State and are not concentrated in a few regional areas."[5]

The ABP includes a single block of nameplate capacity for each of six program categories (Small DG, Large DG, Traditional Community Solar, Community-Driven Community Solar, Equity Eligible Contractors, and Public Schools), across two geographic groups (Group A includes Ameren, MidAmerican, Mt. Carmel, and Cooperatives and Municipal Utilities located in MISO; Group B includes ComEd, and Cooperatives and Municipal Utilities located in PJM). "For each category, for each delivery year, IPA determines the amount of generation capacity in each block, as well as the purchase price for each block, provided that the purchase price provided and the total amount of generation in all blocks for all categories are sufficient to meet the goals in subsection (c)."[6] (Subsection (c) is the Renewable Portfolio Standard.)

IPA may periodically review its prior decisions establishing the amount of generation capacity in each block, and the purchase price for each block, and may propose, on an expedited basis, changes to these previously set values, including but not limited to redistributing these amounts and the available funds as necessary and appropriate, subject to PUC approval as part of the periodic plan revision process described in Section 16-111.5 of the Public Utilities Act."[7]

Program History: Illinois Solar For All

The goal of the ILSFA program is to bring PV to the State's low-income and environmental justice (EJ) communities in a manner that maximizes the development of new PV-generating facilities and to create a statewide long-term, low-income solar marketplace. IPA strives "to ensure that RECs procured through ILSFA and its subprograms are purchased from projects across the State's low-income and EJ communities, including both urban and rural areas, are not concentrated in only a few communities, and do not exclude certain low-income or EJ communities."[8]

The prices of ILSFA RECs must be "determined through a formula, through the development, review, and approval of the Agency's long-term renewable resources procurement …." with the ultimate goal of creating a competitive market for low-income solar.[9]

Following the ICC's approval of ILSFA, either IPA or another party may propose adjustments to the program terms, conditions, and requirements, including the price offered to new systems, to ensure the long-term viability and success of the program."[10] IPA or a contracting electric utility shall purchase RECs from generation once the device is interconnected and verified as energized. Payments for RECs shall be in exchange for all RECs generated by the system during the first 15 years of operation and shall be structured to overcome barriers to participation in the solar market by the low-income community." [11] This translated into an upfront REC payment, wherein qualified projects received payment for 15 years' worth of RECs upon the commencement of commercial operation. .

REC Pricing Approach

The ABP and ILSFA have been implemented as cost-based programs. REC prices are calculated each year and for each eligible project category by taking the difference between the estimated 25-year levelized cost of energy (LCOE) and the estimated 25-year levelized net metering credit. . The LCOE serves as the project's assumed revenue requirement. . The levelized net metering credit serves as the assumed market value of production. . The difference (if any) represents the "missing money" required to enable the project's sponsor to achieve an assumed rate of return. . When divided by 15 years of expected kWh production, this dollar value translates into the REC incentive per kWh assumed required to attract market participation. . In conjunction with the front-loaded payment structure, this REC pricing approach is intended to enable project developers to consistently attract financing and to support a long-term, sustainable renewable energy market for Illinois.

REC prices for each applicable category are recalculated annually. . Every other year, IPA evaluates the overall REC pricing approach through the Long-Term Renewable Resources Procurement Plan process., Both the annual REC price setting and Long-Term Plan processes encourage stakeholder participation and feedback. . ABP policy design elements and REC prices flow from this process. . ILSFA REC prices use ABP REC prices as a starting point and then apply adjustments to achieve stated policy objectives, including but not limited to mandatory minimum customer savings.

Climate and Equitable Jobs Act (CEJA) induces updates to ABP and ILSFA

CEJA set a target of 100% clean energy by 2050, and significantly increased solar and wind REC procurement targets. CEJA amended ABP and ILSFA capacity allocations, utility-scale wind and solar REC price formulations, and some ABP REC contract payments.

CEJA updates to ABP

CEJA created additional ABP capacity categories for community-driven community solar; public schools (with a priority for EJ and Tier 1 and Tier 2 school district projects), and projects developed by equity eligible contractors (EEC). To qualify as an EEC, the entity must be majority-owned by an individual who has graduated from a certified job training programs, is a former member of the foster care system in Illinois, is a formerly incarcerated person, or someone who lives in an equity eligible investment community; or is an independent contractor meeting the same qualifications.[12] CEJA also updated existing ABP and ILSFA categories, increasing the maximum size for small DG from 10 kW to 25 kW, increasing the size of large DG from 10kW-2MW to 25kW-5MW, and expanding community solar to be less than or equal to 5 MW for an individual project. CEJA also required ABP blocks to be sized annually and removed IPA's discretionary capacity (previously 25%) – instead, allocating unused capacity via waitlists. To reflect new block structures mandated by CEJA, the IPA will conduct an annual refresh of the REC pricing model, updating inputs and seeking stakeholder feedback. . The IPA has the authority to change REC prices up to 10% annually without ICC approval.

CEJA also revised ABP contract parameters. Small DG utilizes 15-year REC contracts, paid 100% up-front. Large DG and community-driven community solar now receive an up-front payment equal to 15% of the total REC contract value, with the remaining 85% spread evenly over the following six years. . The total REC contract volume is based on 15 years' worth of estimated production. Traditional community solar and public-school projects now utilize 20-year REC contracts, with payments for RECs made monthly based on actual delivered quantities.

CEJA updates to ILSFA

CEJA also revised ILSFA by making sub-program modifications, shifting sub-program funding percentages, and mandating that a portion of each ILSFA sub-program be reserved for promoting energy sovereignty.

CEJA eliminated the Community Solar Pilot procurement, and divided the Low-Income DG into two subprograms, the Large Multifamily subprogram and the Single-Family and Small Multifamily subprogram.

CEJA shifted subprogram funding allocation percentages. Funding for Low-Income DG (including low-income single-family, small multifamily, and large multifamily) rose from 22.5% to 35%; low-income community solar funding increased from 37.5% to 40%, and funding for non-profits and public facilities increased grew from 15% to 25%. Public Schools will be phased out of ILSFA after 2022-2023 delivery year, as public schools now have a dedicated sub-category in ABP. IPA will reserve 25% of each sub-program for energy sovereignty and 25% for EJ communities.

REC pricing policy design principles and options

Policy Design Principles

Efficient, effective, and lasting DG program design is born from public policy guidance (e.g., legislation and/or regulation) that is clear about what it is trying to accomplish. Intended outcomes should be specified and measurable. . For the Illinois Shines program (hereafter referred to as ABP), the objective is to contribute specified MWs of eligible DG resources towards RPS compliance. ILSFA establishes added objectives related to income-eligible and environmental justice communities. Illinois' enabling legislation and regulation goes on to specify annual targets for multiple subsets of desired resources, which enables policymakers to track progress towards their objectives and make educated decisions about program adjustments, if necessary, to achieve either original or evolving program objectives. .

While singular focus makes policy design easier, it is common for renewable energy policies to have multiple – and sometimes competing – objectives. Policy design choices almost always require identifying and making trade-offs. For example, 'rapid deployment' (i.e., building as much as possible as quickly as possible) and 'least cost' (i.e., building only those resources that meet a cost threshold) suggest significant differences in program design. It is also challenging to balance the desire for simplicity with the objective of incentivizing specific project types and customer groups. . Therefore, it is also important to clearly articulate how to *prioritize* different objectives, so that course corrections can be made to support the most important objectives. Naturally, opinions regarding prioritization of objectives will vary by stakeholder group. . For this reason, policymakers bear responsibility for evaluating stakeholder preferences within a policy design framework and making decisions based on the information available and on empirical data from other renewable energy markets.

Through practical experience across geographies and over time, market participants and policymakers have generally concluded that:

- Policies prioritizing cost effectiveness (especially 'least cost') generally favor competitive procurements of RECs (or bundled energy and RECs) open to all RPS-eligible technologies and project types, which allow larger projects (within the set of eligible projects) to gain advantage through economies of scale and exert downward pressure on price.
- Policies prioritizing rapid deployment generally impose an obligation to purchase on retail providers and then allow the market to set the REC price (although often subject to a cap, to mitigate ratepayer impact if the market is undersupplied).

- Policies prioritizing one or more specific market segments, or with multi-faceted objectives related to technology, project type, and project size categories, tend to establish more prescriptive designs - such as standard offer incentives - intended to provide the predictability necessary to attract market participants and grow targeted market segments.

Illinois' ABP and ILSFA program objectives largely align with this third category of supporting multiple market segments. The programs allocate the overall capacity between numerous project types, including small and large behind the meter DG, community solar (both traditional and community- driven), and public schools. . ILSFA also prioritizes specific offtaker classes by providing added REC-based compensation to cover the cost of acquiring said offtakers. Finally, both ABP and ILSFA have a statutory mandate so ensure projects are located in diverse locations across that state.[13]

The ABP and ILSFA programs seek to grow the in-state solar market in a "steady, predictable, and sustainable" manner.[14] To achieve this, the programs provide compensation at levels that are intended to project costs plus a risk-adjusted rate of return. The objective is to attract market participation sufficient to meet annual MW deployment targets. The REC price, quantity, and payment schedule are known to market participants when they apply, providing a critical degree of revenue certainty, which is intended to lower the cost of project financing. Programs with similar objectives have been implemented in other states. Common design elements include:

- Payments are guaranteed for qualified projects (often subject to capacity limits as a means of ratepayer cost control)
- Pricing is either fixed (specified $/kWh) or knowable (i.e., able to be calculated via formula)
- Purchaser (typically the regulated utility) has a 'must-take' or a minimum quantity commitment, which could apply to any combination of energy, capacity, and/or Recess
- Contract duration is long enough to support project financing (typically 15 to 20 years)
- Bundled Price (Energy + REC) or Strike Price (for indexed REC)
- Incentive rates are updated periodically; new rates apply to new program entrants. Once a project is enrolled in the program, its contract terms do not change (unless specific triggers and changes were specified in advance).

Overall, the policy choices embedded in the degree of subcategory differentiation (and allocation of MW thereto) drive the balance between cost effectiveness and other policy objectives.

Many states have implemented DG REC incentive programs in various forms across the past few decades. We discuss several case studies below and elaborate upon whether these programs might be suitable for the Illinois statutory framework. .

Policy Design Options

Market-Based Programs

Several states have elected to set carve-outs within the RPS for minimum compliance from certain DG resources, and then allowed the forces of supply and demand to set the REC price and (presumably) encourage market entry. Massachusetts' SREC I and SREC II programs, launched in 2010 and 2014 respectively, are notable examples. A purchase obligation (as a percentage of retail load) was placed on MA load-serving entities, who then acquired SRECs through a multi-round auction process. As with all RPS markets, an Alternative Compliance Payment (ACP) served as an SREC price cap and ratepayer protection mechanism. . The SREC ACP was set much higher than the MA Class I ACP due to the SREC program's specific eligibility criteria and deployment targets. . Uniquely, the SREC program also included a "price support mechanism" to prevent prices from falling sharply during periods of oversupply.[15] As in IL, MA SREC projects earn revenue from both RECs and net metering credits.[16]

The market-based approach has several characteristics that make it challenging for DG deployment in Illinois. First, the SREC model is likely not permitted under the ABP and ILSFA statute, as the prices are not known or calculable ahead of each auction. While the SREC programs successfully enabled rapid deployment of DG solar resources in MA, the price of RECs was – by definition – market-based, and not aligned with projects' actual LCOE or total revenue requirement. SREC markets were volatile, and placed significant risk on project investors, who required premium returns as a result. SREC markets were often undersupplied, and prices hovered around ACP rates, despite the declining costs of deploying new solar during the late 2010s.[17] The program achieved its 'rapid deployment' objectives, with premium SREC prices ultimately borne by ratepayers. Eventually, the eligibility of certain SREC projects was truncated (to 10 years) by the Massachusetts Department of Energy Resources, citing high ratepayer impacts. MA then transitioned to its SMART policy – its second-generation solar policy, which is discussed further in the 'hybrid programs' section below. Overall, the SREC approach is not recommended for Illinois.

Value-Based Programs

The value-based approach considers both the commodities and ancillary services delivered and then compensates the (DG) facility with the estimated monetary value of its contributions to the electric grid, the environment, and broader society. In general, this approach focuses on the market value of location- and time-based production and intends to limit cost-shifting between program participants and non-participants by paying DG for the costs it helps ratepayers, in aggregate, to avoid.

A premiere example of a value-based DG program is the New York State Value of Distributed Resources (VDER) tariff, also referred to as the Value Stack tariff. Under VDER, compensation is tied to quantifiable benefits of distributed solar within the New York Independent System Operator (NYISO) control area. The individual benefits of distributed solar are evaluated separately, and are assigned a monetary value, in cents per kWh. Injections to the grid are measured monthly, and the DG facility owner is paid based upon the grid injection only. PV production consumed behind the meter (BTM) is treated as load reduction (and can be valued by the asset owner at actual avoided cost).

The NY VDER Value Stack has five elements:[18]

- Energy Value: Variable, based on NYISO Location-Based Marginal Prices (LBMPs)
- Capacity Value: Variable, based on NYISO capacity rates
- Environmental Value: Fixed, administratively-set, acts in place of REC revenue
- Locational System Relief Value: Fixed, administratively-set, compensation for projects in highly constrained areas
- Demand Reduction Value: Fixed, administratively-set

The Value Stack is also closely tied to the Community Credit, which is a fixed, administratively set incentive exclusive to community distributed generation projects. Note that the Community Credit has now been supplanted by a Community Adder $/kW incentive.

The VDER program is not the sole source of state incentives for DG in New York State. Most solar projects participating in VDER also qualify for the NY-Sun program, through which a project can receive additional incentives. NY-Sun provides a variety of incentives with values that differ based on project size, location, land use, and environmental justice characteristics. The frequency of NY-Sun incentive adjustments has enabled New York policymakers to tailor these incentives to fill revenue gaps for VDER projects that contribute toward public policy objectives. Therefore, while VDER is a value-based program, the combination of VDER and NY-Sun function similarly to a cost-based program. Overall, the state administering any solar program has an interest in ensuring that participating projects are deployed, which often necessitates some form of missing money incentive (when such programs are not structured as bundled procurements).

Cost-based Programs

Many state-sponsored programs track the total cost of deploying DG resources and then set incentive rates at levels that are intended to cover installed costs, operating costs, and a reasonable rate of return for project investors. Ideally, this approach enables states to achieve deployment targets, offer market entrants the opportunity for risk-adjusted returns, and protect ratepayers from overpayment. Accomplishing these goals requires robust data collection and analysis, to establish (and maintain) incentives that are aligned with market conditions. . For example, material, labor, financing, and other costs vary over time, and the condition of global supply chains since 2020 has demonstrated that historical trajectories (while relevant and critical to understand) are not the only metric to consider when establishing – or revising – incentives for future years. Cost-based incentive-setting also requires careful consideration of the breakpoints for economies of scale. Smaller resources tend to have a higher dollar/kWh LCOE, and it is often not the intent of the programs for only the largest projects within an eligibility category (e.g., 1-5 MW) to be economically viable. Nor is it often the intent to set incentive levels at prices that allow all projects to be economical. Rather incentive levels should be set based upon a "*representative* project" with the understanding that actual costs will vary. Incentives for *various* resource types, sizes, and/or use cases are often differentiated, with *compensation* amounts adjusted to *suit state-specific public policy objectives*.

An important consideration for any cost-based incentive program is how the LCOE revenue requirement is calculated. Broadly, there are two primary approaches to cost-based incentive modeling. Recovery factor analyses translate capital expenditures and financing costs into an annual "factor" that is multiplied by total project cost. . Estimates of annual operating expenses are added to arrive at a total cost of energy per kWh. An example of this approach is the "Economic carrying-charge rate" which amortizes all costs to produce a stream of annual payments, which can either be calculated as a 'year one' value that escalates or as a levelized payment. While well understood and commonly used to estimate LCOE for fossil generating technologies (where tax incentives are spread widely across the value chain), recovery factor analyses struggle to accurately account for the structure of renewable energy tax benefits, which are concentrated at the point of generation. . Recovery factor analyses are also challenged to accurately account for periodic capital expenditures (such as inverter replacements) required for long-term operation.

Discounted cash flow (DCF) analyses (including the CREST model, as deployed in Illinois) incorporate cost, financing, and performance inputs to produce a year-by-year forecast of project cash flows. These annual cash flows are used to derive an after-tax net present value (NPV). . The targeted rate of return has been achieved when the calculated NPV is zero. . Modeling assumptions can be differentiated to determine the revenue requirement – and subsequently the incentive requirement – for each policy category. Incentives calculated in this manner provide reasonable certainty that a project will be able to cover all costs and meet the investors' assumed minimum required rate of return.

The ABP and ILSFA programs discussed in this Whitepaper are both prominent national examples of cost-based programs. The Rhode Island Renewable Energy Growth (REG) program is another example, although it also shares some elements in common with procurement programs.[19][20] Within Rhode Island REG, the program's total MWs are allocated between different technologies and project types, and then DCF modeling is performed to set dollar/MWh "ceiling prices" for each category. These ceiling prices are approved by both a Distributed Generation Board[21] and the Rhode Island Public Utility Commission (PUC) and serve as a cap on the incentive payment. Projects less than or equal to 25 kW_{AC} are compensated at the ceiling price (i.e., there is no competitive bidding). Additional projects may enroll until the annual MW capacity allocation is reached. Projects greater than 25 kW_{AC} must competitively bid their proposed pricing at or below the ceiling price during one of three annual enrollment periods. The distribution utility reviews applications to ensure all minimum criteria are met, and then selects incentive awardees based on price (from lowest to highest) until the block is full. Selected projects are entitled to a 20-year contract (with the regulated utility) for energy and RECs. It is a common feature among DG programs with elements of competitive procurement (e.g., Rhode Island REG, Connecticut NRES) that smaller resources are provided with a standard rate of compensation (typically on a first-come, first-served basis). It is widely accepted that the simplicity of this approach – and resulting deployment of small solar installations – outweighs the potential benefit of competitive bidding within residential and small commercial categories.

Notably, the REG program is what is known as a "buy-all, sell-all" program. The tariff between the distribution utility and the selected REG project obligates the utility to purchase all energy and RECs produced by the projects over the tariff period (15 years for residential, 20 years for all others). REG tariffs are not tied to retail rates or net metering credits; as a result, asset owners have revenue rate certainty for the life of the tariff – which enables lower cost financing by reducing risk, but also removes potential upside if retail rates rise more than forecasted estimates. This benefits ratepayers by removing energy price risk, which results in lower (implied) REC premium. By comparison, the Illinois programs establish a REC-only incentive price based on forecasted estimates of net metering credits. While the REC payment is fixed, each project's total revenue depends on realized net metering credit values over the life of the project – which leaves more risk with the project sponsor than the REG program. As a result, actual project returns could be higher or lower than the target IRR used to calculate the REC price incentive. We understand, of course, that not all aspects of the Rhode Island REG program are authorized under Illinois' current enabling legislation. Nonetheless, we believe the comparison provides a useful illustration of the relationship between compensation design, project returns, and ratepayer impact. Table 1 provides an overview of DER incentive compensation structures across several states – highlighting the fixed and variable components of each.

Table 1: Overview of DER Incentive Compensation Structures

DER Incentive Program	Fixed $/kWh Components	Variable $/kWh Components	Comment
CT Net Metering	n/a	NM Rate & Class I RECs	
CT ZREC	Class I RECs	Retail, NM or Wholesale Rate	
DE Community Solar	n/a	Retail Rate	Distribution + Supply Service only
IL Adjustable Block	RECs	Retail energy and transmission only for Community Solar	RECs valued at the modeled "missing money" rate
MA SMART Stand-alone	Sum of Incentive + Value of Energy Rates	Generally, n/a, but exceptions exist	Declining Block program; RECs claimed by EDC.
MA SMART BTM	Incentive Rate	Retail, NM or Wholesale Rate	Declining Block program; RECs claimed by EDC
MA SREC	n/a	SRECs & Retail, NM or Wholesale Rate	
ME DG Procurement	Value of Energy	Class I RECs	Declining Block program
ME Net Energy Billing 1.0	n/a	NEB Rate & Class I RECs	Offers NEB kWh Credit and NEB Tariff Rate variants
ME Net Energy Billing 2.0	NEB Tariff Rate	Class I RECs; NEB kWh Credit	
NY VDER	E, DRV, LSRV & MTC / Community Credit	LBMP & Capacity	DRV only fixed for first 10 years

NY Net Metering (On-site BTM)	n/a	Retail Rate, non-tradable RECs	Restricted to ≤ 750 kW
NH Net Metering	n/a	NM Rate & Class I/II RECs	
NJ SREC-II ADI	SREC-IIs	Retail, NM or Wholesale Rate	SREC-IIs fixed for 15 years
NM Community Solar	n/a	Retail Rate & RECs	Only generation, FPPCAC, and transmission components of retail rate
RI REG Program	Incentive Rate	n/a	Incentive rate fixed for 15-20 years; RECs claimed by EDC
RI Net Metering	n/a	NM Rate & Class I RECs	
VT Standard Offer	Incentive Rate	n/a	Incentive rate fixed for 15-25 years; RECs claimed by EDC
VT Net Metering	n/a	NM Rate & Class II RECs	RECs retained or claimed by EDC
Acronym key:	ADI = Administratively Determined Incentive; BTM = Behind-the-Meter; DBI = Declining Block Program; DRV = Demand Reduction Value; E = Environmental Value; FPPCAC = Fuel and Purchased Power Cost Adjustment Clause; LBMP = Locational Based Marginal Price a/k/a energy value; LSRV = Locational System Relief Value; NEB = Net Energy Billing; NM = Net Metering; RECs = Renewable Energy Certificates; SRECs = Solar Renewable Energy Certificates; VDER = Value of Distributed Energy Resources.		

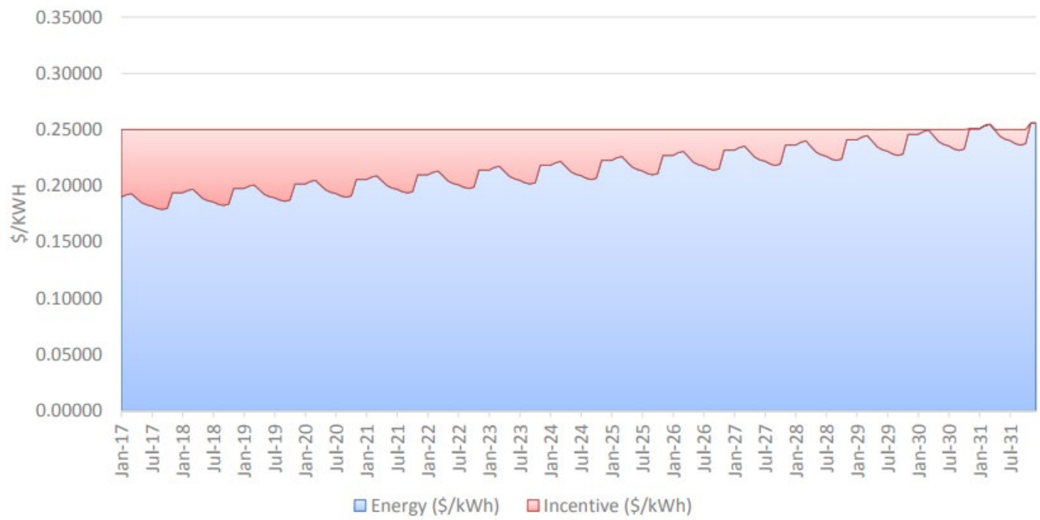
Hybrid Approaches

The previously described program structures are not mutually exclusive. Some programs incorporate elements of several of the options described above. While there are too many permutations to discuss here, we believe the Solar Massachusetts Renewable Target (SMART) Program represents a hybrid approach to program design worth elaboration.[22]

The SMART program is a feed-in-tariff based, declining block program. Compensation on the utility side of the meter (front of the meter, FTM) is held constant at administratively set prices. Projects obtain compensation through net metering (called the Value of Energy), with a REC incentive price to fill in the missing money. Unlike the Illinois programs, the REC price varies based upon the realized Value of Energy to meet the administratively set total compensation level, which was designed to meet project revenue requirements. The total compensation declines between program blocks (on the assumption that project costs will decline), and projects lock in their total compensation rate at the time of program qualification. Projects can receive adders or subtractors based upon siting characteristics and offtake. The SMART program does not reevaluate project revenue requirements and re-set REC prices on a regular basis, although the applicable regulatory authority has some discretion to adjust prices. SMART has discrete resource blocks for different sizes and configurations of solar resources.

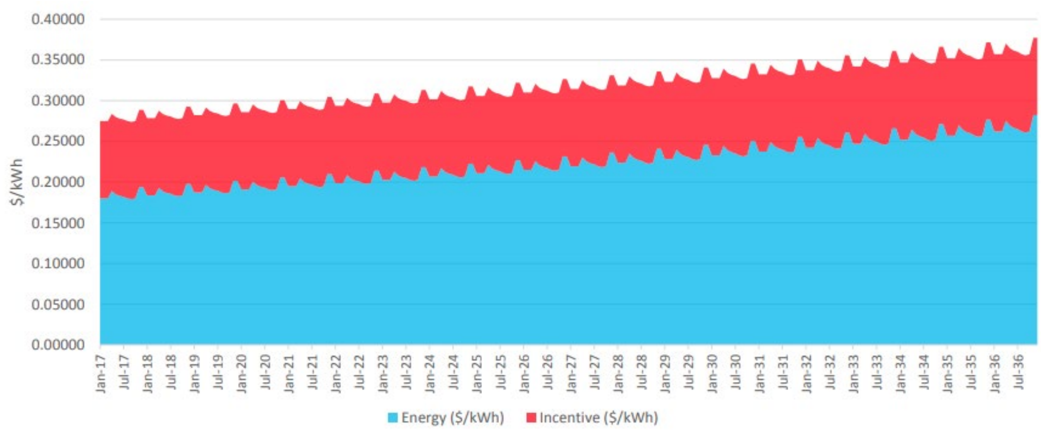
Notably, the SMART program REC incentive can never be negative, even if, as during the winter of 2022-2023, the Value of Energy exceeds the administratively set price (i.e., revenue requirement). Figure 1 (from the Massachusetts Department of Energy Resources) provides an illustrative example of SMART compensation for a FTM system.

Figure 1: Illustration of MA SMART Standalone DER Compensation Structure



Behind the meter (BTM) SMART compensation is more akin to the Illinois model, with projects locking in a constant REC incentive level for the life of the tariff, see Figure 2 below.

Figure 2: Illustration of MA SMART Behind-the-Meter (BTM) DER Compensation



[23]

Consideration of Market-Based Adjustments

Earlier sections of this Whitepaper discussed the importance of aligning policy design choices with prioritized policy objectives. This process often results in hybrid approaches to policy design, which often include mechanisms to adjust incentive rates over time. Some Illinois stakeholders have expressed a preference for exploring market-based rates or market-based adjustments to cost-based rates. As a result, market-based approaches are considered as part of this independent review.

Supply and demand are the drivers of market-based pricing. The ABP and ILSFA programs effectively set demand for DG and community solar in Illinois, as allocated to the separate project categories. The availability and interest of supply to meet that demand is a function of project economics (including the offered incentive) and the expectations surrounding long-term market potential (i.e., will the market support a local industry or will it be a short-term 'flash in the pan'). As currently structured, the Illinois programs reset cost-based incentive pricing each year, but there is no mechanism to factor in the degree to which supply has been deployed in Illinois to meet category-specific demand. This section considered the possible merits of deployment-based adjustments.

Cost-based modeling intends to capture changes in market conditions by updating key cost, performance, and financing assumptions over time, including changes to be experienced during future years (such as the two years of the Long-Term Plan). The paradox of cost-based modeling, however, is that actual (verifiable) data are most often historical data. Cost-based modeling therefore attempts to consider both recent historical data and current estimates when setting incentives for current or future program years. While this approach generally works very well, there may be non-price factors that are not captured by cost-based modeling but which nonetheless influence market participation and resource deployment. These influences may eventually become measurable and show up in historical data, but there is likely to be a significant time lag between their impact on the market and their influence on publicly available data sets. Exogenous factors that are not reasonably foreseeable may also arise. A mechanism that allows for price adjustments based on market participation may bring some of the benefits of competitive procurements into an otherwise cost-based program. It is important to note at the outset, however, that as the volume and detail of data feeding the annual, cost-based incentive calculation increases, it is more likely that the initial cost-based rates will support deployment in line with annual MW targets and less likely that subsequent market-based adjustments will be necessary. To this end, market-based adjustments should rely on criteria established in advance, and only triggered if those criteria are met.

One option for reflecting each year's supply-demand balance in a subsequent year's program prices would be a "post-processing" adjustment to cost-based REC prices. In this example, the annual REC prices would be adjusted automatically if the prior year's supply/demand balance met specified criteria (by program category). For example, if a category were sufficiently undersubscribed, the following year's cost-based REC price would be adjusted upward. This would be intended to send a stronger price signal in hopes of attracting more market participation for the subject category. If a category were sufficiently oversubscribed, the REC price would be adjusted downward – to align with the expectation that policy targets could still be met by offering a somewhat lower incentive. Detailed recommendations associated with this design concept are provided later in this whitepaper. This approach can, of course, be augmented to include policymaker review and stakeholder comment steps.

A post -processing mechanism, if adopted, would not replace the annual cost modeling. Instead, it would serve as an additional tool to help achieve the overall policy objectives – fostering robust deployment of DG within each program category while also providing a transparent pricing adjustment mechanism responsive to market conditions.

Consideration of Specific Project Types

The ABP and ILSFA program are designed to distribute the benefits of solar to a broad range of Illinois ratepayers. The programs – and their enabling legislation – specify both single- and multi-family low-income residential projects, as well as non-profits and public facilities (including public schools) as project types designated for support. Policymakers intended this support to result in both incremental solar project deployment and long-term customer savings. To accomplish these goals, policymakers will need to understand and address the barriers to entry in these market sectors. This work is underway, through several pilot programs and customer type-specific initiatives intended to better understand, and address, how the structure and delivery of solar energy options can be adapted to benefit a wider audience. This section addresses some of the dynamics related to specific project types.

ILSFA program

ILSFA is undertaking two pilot programs, both targeted at the Single-Family subprogram. One pilot program examines the effect of incentives for fund low-income home repairs and upgrades on the maximization of solar-related benefits to LMI homeowners. The other, referred to as the Program Delivery Pilot or the Residential Solar Pilot, will evaluate whether a more consolidated, vertically integrated program delivery model will increase uptake in the targeted subcategories.[24] For example, the program will explore whether bundling roof repair and solar installation incentives create a multiplier effect on benefits to low-income ratepayers. The RFP for the Residential Pilot has been issued, and the program will run through at least June 30, 2024.[25]

This Whitepaper makes recommendations that may be applicable to the single- family ILSFA subprogram. However, the findings of the pilot programs should inform any implementation of Whitepaper Recommendations. The pilot programs will provide data from on-the-ground sources about program barriers and potential solutions that should further contextualize the recommendations herein.

Furthermore, it may be the case that the incremental REC price needed to incentivize sufficient participation with the ILSFA residential subprogram populations do not fall along the typical standard deviation. If, by way of example, a significant number of households eligible for the Single Family ILSFA subprogram have cost-based barriers to program participation such as those that will be examined in the Home Repairs and Upgrades Pilot, then taking the straight average of either the subprogram's modeled costs or the historical installed cost data for the subprogram would not enable those residents to participate. Or, to take another hypothetical, there may be non-price barriers to ILSFA adoption that are not readily addressable with REC price increases, such as community trust of salespersons, where increased monetary incentives may not be an effective use of ratepayer dollars.

Incremental Cost Treatment

When designing or revising a cost-based program, price caps on incentives for specific project types should only be implemented where verifiable cost data is available for each project type. For example, community solar projects can benefit from economies of scale vs smaller, rooftop projects. But compared to similarly sized and sited projects with only one offtaker, a community solar project has incremental costs related to customer acquisition. Under Illinois' structure, REC pricing will also vary based on the difference in net metering credit value between DG, community solar, and other projects.

Both perspectives should be considered when setting incentives and MW allocations. In the Rhode Island REG program, for example, the incremental incentive for Community Remote Distributed Generation projects is capped at 15% above similarly sized projects that do not have customer acquisition costs, even though it is possible that the actual incremental costs for community solar projects may exceed this premium. As a result, Community Remote Distributed Generation in Rhode Island is consistently undersubscribed.

Temporary Public Schools/ Public Facilities Overlap

CEJA created a Public Schools category within the ABP program. The 2022 Plan creates a one-year grace period (i.e., the 2022-2023 program year), during which a public-school project can qualify for either the ABP Public School category or the ILSFA Non-Profits and Public Facilities subprogram. The rationale is that there may be public school projects in development that have begun to arrange financing under the ILSFA program.[26] ILSFA offers higher REC incentive rates than the ABP program. There are also other considerations, such as developer and offtaker familiarity with the ILSFA program and relatively unfamiliarity with the Public Schools category, and different payment structures for the program categories. Taken together, these factors may help explain low participation in the new ABP Public Schools category.

IRA Impacts

The Inflation Reduction Act (IRA) was signed into law on August 16, 2022, as Public Law No: 117-169, and both expanded and extended tax credits. Therefore, the IRA will have a significant impact on missing money calculations for the REC payments in the ILSFA program. The IRA increased ITC values, created a successor Clean Energy Investment Credit (CEIC), allows some entities to receive ITC through direct payments, created new ITC bonus credits, and allows projects to include interconnection property in the basis for calculating project ITC values.

ITC expansion and extension: The IRA increased the maximum ITC credit rate from 22% to 30%. Projects receive a 6% base credit value but can receive the full 30% statutory credit values by meeting specific prevailing wage and apprenticeship requirements. To qualify for the full ITC value, all projects over 1 MW and employing four or more people must:

- Pay Davis-Bacon prevailing wage for the given region and trade, and
- Employ certified apprentices to complete the following percentage of total project labor hours:
    - 10% of total labor hours for projects that begin construction in 2022,
    - 12.5% for projects that begin construction in 2023, and
    - 15% for any project that begins construction after December 31, 2023.

These federal requirements serve as minimum for achieving the 30% ITC. Each state may, of course, elect to apply incremental conditions. Any projects over 1 MW that employ four or more people that do not meet these criteria would only qualify for the 6% ITC, not the 30% ITC. Any projects under 1 MW automatically qualify for the full 30% ITC. It is unclear without further clarification from the Internal Revenue Service (IRS) whether the reference to “four or more people” applies to ongoing jobs at the site, the number employed by the taxpayer at any given time, or just an installation crew that undertakes multiple jobs. The implications of different interpretations are material.

Projects must start construction by 2024 to qualify for the newly increased ITC and must be placed in service in 2023 or later. The IRA removed a placed-in-service deadline, but it is our understanding that in the absence of the placed-in-service deadline, projects beginning construction under the extended ITC would still be subject to the four-year “Continuity Safe Harbor,” in which the project would have to show “continuous efforts” to retain its eligibility for up to four years after having begun construction. Projects placed in service starting in 2025 will qualify for the ITC successor, the CEIC.

ITC bonus credits: Projects may increase the value of their ITC payments by 10% if the project uses at least a minimum amount of steel and iron manufactured in the United States. For solar projects, the domestic content bonus thresholds are:

- 40% for projects beginning construction in tax years 2022 through 2024
- 45% for projects beginning construction in tax year 2025
- 50% for projects beginning construction in tax year 2026
- 55% for projects beginning construction in tax year 2027 and thereafter.

Projects placed in service on or after 2023 or that begin construction through 2024 can also receive an additional 10% ITC increase for projects located on brownfields. Projects can also receive an ITC bonus if they are located in the following communities:

- The project is located in a low-income community (10% ITC bonus, 700 MW available)
- The project is located on Indian land (10% ITC bonus, 200 MW available)
- The project is part of a qualified low-income residential building project (20% ITC bonus, 200 MW available)
- The project is part of a qualified low-income economic benefit project (20% ITC bonus, 700 MW available)

The bonus credit value would only be available to the first 1,800 MW_{DC} of projects through 2024, after which the CEIC will succeed it. The project must be placed in service within four years of the date the applicant was notified of receiving capacity allocation under the program. The Secretary of the Treasury and Administer of the Environmental Protection Agency are required to create a process to allocate capacity to environmental justice communities.

Energy Community Tax Credit Bonus: The IRA offers a 10% bonus tax credit to (1)'Census tracts and directly adjoining tracts that have had coal mine closures since 1999 or coal-fired electric generating units retirements since 2009,' or (2) Metropolitan statistical areas and non-metropolitan statistical areas that have 0.17% or greater direct employment related to extraction, processing, transport, or storage of coal, oil, or natural gas. The Department of Energy provides a map of these energy communities.

ITC interconnection property inclusion: Projects less than or equal to 5 MW can now include transmission or distribution interconnection property in the basis for calculating project ITC value, regardless of whether an electric utility owns the interconnection property.

ITC direct payments: Tax-exempt, governmental or tribal entities, including state and local governments and electric coops, can claim full ITC direct pay through 2024 and CEIC direct pay from 2025 until it is phased out. To qualify for direct payments, a project must meet the domestic content threshold, though this requirement can be waived if using domestically manufactured material would increase total project costs by more than 25%.

CEIC successor: The CEIC supersedes the ITC for projects that are placed into service in 2025 and thereafter. The CEIC phases out when United States electricity sector emissions fall to 75% below 2022 levels or December 31, 2031, whichever is later. Given the expected pace of grid decarbonization, the credits serve to functionally create semi-permanent tax credits for new or upgrades to existing solar generation. Like the ITC, the CEIC value starts at 6%, but increases to 30% for projects over 1 MW if they meet the same prevailing wage and apprenticeship requirements as in the ITC. Projects 1 MW or less will automatically qualify for the 30% CEIC regardless of whether the prevailing wage and apprenticeship requirements are met. The CEIC also will have the same brownfield, domestic content, and environmental justice community bonuses as the ITC had. CEIC projects will also be allowed to include transmission and distribution system upgrades required for interconnection in the basis for determining their CEIC value.

IRA Modeling Implications

For cost-based programs like the ABP and ILSFA to be effective, compensation must reflect accurate cost, performance, and financing conditions for projects in the Illinois distributed solar market. In particular, financing conditions are impacted by the tax credits and other tax policies recently enacted via the IRA. Program administrators must provide appropriate market signals for viable projects to seek qualification in the program. Therefore, it is important that modeling efforts account for impacts that the program would have on projects that are already common and on those that may require more significant policy changes to support. Key modeling implications are organized below by project type, including an overview in Table 2.

Table 2: IRA Modeling Implications by Program Category

	30% ITC/CEIC Eligible	Prevailing Wage Requirement*	Interconnection Equipment Costs in Tax Basis	Direct Payment Eligible	Eligible for Credit Transfer	Eligible for 10% Domestic Sourcing Credit	Eligible for 10% "Energy Communities" Bonus Credit	Eligible for +10% "Located in a Low-Income Community" Bonus Credit	Eligible for 20% "Low Income Economic Benefit" Bonus Credit
ABP Small DG	✓	X	X	X	Unclear	X	Geographically Limited**	Selection Limited***	Selection-Limited***
ABP Large DG and Traditional Community Solar	✓	X	✓	X	Unclear	X	Geographically Limited**	Selection Limited***	Selection-Limited***
ABP Community-Driven Community Solar	✓	X	✓	Sometimes	X	X	Geographically Limited**	Selection Limited***	Selection-Limited***
ABP Public School Projects	Sometimes	X	✓	✓	X	✓	Geographically Limited**	Selection Limited***	Selection-Limited***
ILSFA Low-income **DG** (1- to 4- unit buildings)	✓	Sometimes	X	X	✓	X	Geographically Limited**	Selection Limited***	Selection-Limited***
ILSFA Low-income **DG** (5+ unit buildings)	✓	Sometimes	Usually	X	✓	X	Geographically Limited**	Selection Limited***	Selection-Limited***
ILSFA Non-profit and Public Projects	✓	Usually	Unclear	Sometimes	✓	✓	Geographically Limited**	Selection Limited***	Selection-Limited***
ILSFA Low-income Community Solar	✓	Usually	Usually	X	✓	X	Geographically Limited**	Selection Limited***	Selection-Limited***

*Although the IRA does not require all projects to meet a federal prevailing wage requirement to qualify for its incentives, the IPA's August 23, 2022 Long-Term Renewable Resources Procurement Plan, pursuant to CEJA, already required most participating projects greater than or equal to 25 kW must pay a state-specified prevailing wage.
** The 10% bonus value available to "energy communities" appears to include ITC-eligible projects of any size and type that are in certain communities with sufficient fossil fuel employment or a coal mine or coal fired power plant closure since 2009.
***The 10% bonus value available to 700 MW nationwide of projects "located in a low-income community" and the 20% bonus value available to 700 MW nationwide of "low income economic benefit" projects are expected to be subject to a selection process undertaken by the Department of the Treasury, Environmental Protection Agency and Department of Energy.

ABP Small Distributed Generation (DG): All ABP and ILSFA projects would be eligible for the 30% ITC. Projects less than 1 MW are not required to meet prevailing wage or apprenticeship requirements to qualify for the full 30% ITC or CEIC, nor this specific category by state law, so modeling efforts should assume that these projects have no incremental prevailing wage costs. It is unclear if there will be incremental costs from apprenticeship requirements. Typically, interconnecting projects less than 25 kW do not trigger significant system modifications as "cost causers" in distribution group studies. However, in the unlikely event that the typical small-scale project owned by a taxable entity begins to need to pay for substantial additional interconnection property, then that property must be included in the ITC or CEIC basis. Small projects are unlikely to be owned by a tax-exempt, governmental, or tribal entity, so these projects should not be modeled as if they are receiving ITC or CEIC direct payments.

ABP Large DG and Traditional Community Solar: Projects over 25 kW are more likely to have interconnection property payments, so those costs should be included in their ITC or CEIC basis. These projects are also unlikely to be owned by a tax-exempt, governmental, or tribal entity, so these projects should not be modeled as if they are receiving ITC or CEIC direct payments.

ABP Community-Driven Community Solar: Community solar projects are large enough that they should be modeled with interconnection property payments included in their ITC or CEIC basis. Community solar projects may use ITC or CEIC direct payments, but only if a project is assumed to be owned by a tax-exempt entity. New credit transferability rules should not be considered because transferability only applies to taxable entities.

ABP Public School Projects: Public school projects should be modeled with a 30% ITC or CEIC, but only if tax-exempt, government-owned, or tribal school-owned projects are modeled to also include increased costs from domestic sourcing. The incremental cost of domestic sourcing could be omitted if it is assumed that projects would waive the domestic sourcing requirement by demonstrating that doing so would increase project costs by over 25%. Pending issuance of federal rules, such projects may be eligible for a 40% tax credit with domestic sourcing. Public school projects should be assumed large enough that they would have interconnection property payments to include in their ITC or CEIC basis. The projects should be assumed to use direct ITC or CEIC payments if they are owned by a tax-exempt entity, such as a school district or a related financing entity.

ILSFA Low-income Distributed Generation (1- to 4- unit buildings): Host-owned projects under 10 kW would not include interconnection property costs in their credit basis because they would qualify for the § 25D credit for individuals, to which the interconnection-in-the-basis allowance does not apply. All other projects in this category should be modeled as if they are including interconnection property costs in their credit basis.

ILSFA Low-income Distributed Generation (5+ unit buildings): Projects should be assumed to include interconnection property costs in their credit basis, except for host-owned projects less than 10 kW. Projects in this category should not be assumed to be receiving direct ITC or CEIC payments because typical projects appear not to be owned by tax-exempt entities. These projects should qualify under the new, forthcoming credit transferability regime.

ILSFA Non-profit and public facilities projects: Non-profit and public facilities projects should be assumed to receive the full 30% ITC or CEIC, but if owned by the non-profit or public facility, then certain costs must be explicitly included or assumed waived for certain projects. If the project is assumed to be directly owned by a tax-exempt, governmental or tribal entity, costs for domestic sourcing would need to be included, or assumed waived if costs can be shown to exceed 25% above typical projects. Pending issuance of federal rules, such projects may be eligible for a 40% tax credit for domestic sourcing. Additionally with the passage of HB3551 on May 27,2023, non-profit and public facilities projects should be modeled to have incremental prevailing wage costs for installation labor unless they are serving houses of worship where aggregated, co-located project capacity does not exceed 100 kW_{AC}. Barring clarification from the Department of the Treasury, it is unclear if non-profit and public facilities projects would be eligible to include their interconnection property costs in their credit basis . Projects should be assumed to receive direct ITC or CEIC payments if they are owned by tax-exempt, governmental, or tribal entities.

ILSFA Low-income community solar: As with non-profit and public facilities projects, with the passage of HB 3351 these projects should be modeled to have incremental prevailing wage costs for installation labor Host-owned projects under 10 kW would not include interconnection property costs in their credit basis, but all other projects should be assumed to do so.

Discussion and Recommendations

This section makes recommendations for policymaker and stakeholder consideration as part of the next Long-Term Renewable Resources Procurement Plan. These recommendations consider current policy objectives and constraints, market performance and dynamics to date, and stakeholder feedback. During our review, we received the following comments from stakeholders:

- Commonwealth Edison (ComEd)
- Siemens, Inc.
- The Joint Non-Governmental Organizations (Joint NGOs, comprised of Vote Solar, the Environmental Law and Policy Center (ELPC), and the Natural Resources Defense Council (NRDC); and
- The Joint Solar Parties (JSPs, comprised of the Solar Energy Industries Association (SEIA), the Coalition for Community Solar Access (CCSA) and the Illinois Solar Energy Association)

Sustainable Energy Advantage appreciates the time that stakeholders invested in their comments and has considered each comment equally.

The recommendations below (which are informed by the above comments) can, in principle, be implemented for the 2024 – 2025 program year. Where additional legislative authority is assumed required, recommendations are discussed separately under the header “Longer-Term Legislative Considerations.”

Where legislative action is required, we believe it is nonetheless reasonable and appropriate to consider the potential long-term benefits of these recommendations for Illinois ratepayers as part of the Long-Term Plan discussion. It may also be appropriate for such topics to lead to requests for further study.

Recommendation 1: Continue to use the Cost-Based Approach to Annual Incentive-Setting

ABP and ILSFA require a high degree of incentive differentiation by project type. This aligns best with the cost-based approach to incentive setting because it allows input assumptions to vary by project type – as an explanation and justification for why different types of projects targeted by the policy require different incentive levels. 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.

Recommendation 2: Continue to use a Discounted Cash Flow model to calculate the revenue requirement for each ABP and ILSFA project category

Discounted cash flow (DCF) models are the industry standard for project finance analyses. In the renewable energy industry, these models are adapted from the traditional pre-tax income approach to an after-tax cash flow approach that is intended to estimate the value of depreciation and tax credit benefits to owner(s) of renewable energy assets. Cash flow modeling in the policymaking context typically assumes efficient use of tax benefits. 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 – described earlier in this Whitepaper – 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.

We further observe that there is no reason not to continue using NREL's CREST model to support the REC price setting process. In fact, the CREST model was built specifically to support state policymakers in cost-based incentive setting proceedings. It was built in Microsoft Excel with no protected or hidden sheets or cells to facilitate maximum transparency during the stakeholder engagement process. For full transparency, we note that Sustainable Energy Advantage was the architect of the original CREST model, under contract to NREL. The tool is robust, and suitable for this process. As with any modeling exercise, however, the value of the output is linked to the detail and reliability of the inputs.

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

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. This makes it much more difficult to make informed decisions about how the incentive-setting policy should be adjusted over time. 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. While rates of return above risk-adjusted levels hold short-term appeal for some market participants, data disclosure and verifiable assumptions are the foundation for a durable program and increase the likelihood that the program will be expanded and extended. Ultimately, the programs that lead to healthy local industry (and the attending local jobs and economic development benefits) are long-running, provide stable year-over-year growth, and offer reasonable rates of returns. These characteristics bring more benefits to market participants and ratepayers than markets that overheat and then stall at the hands of improperly set incentives. The Joint NGOs' comments recognize this net benefit, stating "the data collected from these requirements will improve the accuracy of future cost-based modeling. As the IPA continues to refine its incentive programs, having access to reliable and detailed project data becomes crucial for developing accurate models that reflect the unique characteristics of the Illinois market. Improved cost-based modeling will enable the IPA to create better-targeted incentives, which will maximize the effectiveness of their programs and ensure that state renewable energy goals are met as efficiently as possible." (JNGO comments page 8)

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. Table 3 demonstrates how other states have effectively balanced data reporting and information sensitivity.

It is also helpful and appropriate to collect the array tilt and azimuth, as well as actual production (which is already collected through the production meter). Actual production data can be used to consider potential adjustments to the capacity factor assumptions in the CREST model.

Table 3: DG program data reporting requirements

State and Program	Required Disclosures	Project Level or Aggregated?	Source	Data Collection Template Link
Massachusetts SREC Program	• Metered production Data for SREC minting	Aggregated	Production Tracking System	Production Tracking System login
Solar Massachusetts Renewable Target (SMART) Program	• Project Applicant/Installer/Owner • Project location • Project capacity • Project type (residential, commercial, rooftop or ground mounted) • Adders or subtractors • Co-located storage details • Total installed cost • Cost per Watt	Project level	Massachusetts Department of Energy Resources Webpage (search for "Qualified Units List")	Program Admin (PowerClerk) Application Portal
New York Sun (NY-Sun) Solar Data	• Project developer • Project location (city, zip code, substation and circuit) • Project type • System size • Estimated annual production • Project installed cost (NYSERDA-only)	Project level	New York Statewide Solar Projects: Beginning 2000	Application Portal Starts Here
California Net Energy Metering (various programs)	(Specifics vary by program) • Project developer ID • Project size • Project type (Residential or Commercial, rooftop or ground mounted) • Co-located storage size • Tilt and azimuth • Total project cost • ITC cost basis	Project basis	California Distributed Generation Statistics	Specifics vary by program and utility, and appear to be tied to interconnection process in some instances (example: PGE Net Metering application)

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

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. The record suggests this common understanding does not yet exist. For example, the ICC states in its July 14, 2022 Order in Docket 22-0231 that "The Commission finds that the record is not clear whether the JSPs are correct regarding the assumptions made in the REC Pricing Model for the transmission and capacity credits, but it is clear that it would be a large undertaking that would impact multiple parts of the REC model. The Commission agrees with the IPA that this should be reviewed prior to the next LTRRPP update and parties should further discuss the JSPs' claims to ensure that the REC Pricing Model accurately reflects the transmission and capacity credits.[27]" As the entities implementing net metering tariffs, the distribution utilities are in the best position to accurately state how net metering credits are currently calculated. Policymakers should then confirm that the utilities are implementing net metering in accordance with the enabling legislation and regulations.

Table 4: Illustrative (ComEd Small Load) Net Metering Credit Billing Determinants

JNGO Description	Tariff Description
Energy Charge	Purchased Electricity Charge and Purchased Electricity Adjustment
Transmission Charge	PJM Service Charge
Capacity Charge	Monthly Capacity Charge (converted from $/kW-mo to $/kWh)
Energy Transition Assistance Charge	Energy Transition Assistance Charge
Energy Efficiency Adjustment	Energy Efficiency Adjustment
Zero Emissions Adjustment	Zero Emissions Adjustment
Renewable Energy Adjustment	Renewable Energy Adjustment
Environmental Cost Recovery Adjustment	Environmental Cost Recovery Adjustment

Table 4 provides a comparison of the JNGO's comments regarding applicable net metering credit billing determinants to the kWh charges listed in ComEd's BES Small Load Delivery Class. A broader review of ComEd rates demonstrates that there are numerous net metering classifications, and application of net metering credits to customer bills varies by classification. The same is assumed true for Ameren. The parties should discuss and agree (a) that this represents the complete list of net metering credit billing determinants and (b) how the Capacity Charge is translated into the net metering credit. It is assumed that the 'Illinois Electricity Distribution Tax Charge' is not included in the net metering credit calculation. This should be confirmed.

Once the kWh billing determinants included in the net metering credit for each applicable customer and project type are clear, the parties can then discuss how each billing determinant should be adjusted over time. We recommend forecasting individual rate billing determinants separately for the purposes of modeling net metering revenue for different types of projects. We note this in the context of both recent historic volatility in energy markets, and the shift to utilizing a five-year historical average for energy and capacity prices for yearly modeling purposes (partly because of this volatility). Ameren has previously recommended using forecasted energy and capacity prices, but this was rejected by the ICC on the grounds that other parties did not have the opportunity to respond, and because forecasts are "frequently not accurate." [28] A more robust stakeholder discussion on the merits of billing determinant-specific net metering credit forecasts would be beneficial.

We agree with the ICC that no forecast is perfect but believe that methodological choices are important to informed decision-making. The current 1% inflator applied to the aggregate net metering rate in the CREST model is a form of forecast.[29] This methodology has the advantage of simplicity, but we struggle to see the correlation between this approach and the expected future behavior of individual net metering billing determinants. This is especially true given the recent volatility in several of the largest billing determinants (energy, transmission, capacity). We believe a more granular approach is warranted. Different net metering billing determinants are subject to different forces and may well move independently of one another.

For example, regression analysis could be applied to some billing determinants, such as energy prices, for which a certain variable is shown to be significantly correlated with billing determinants, such as natural gas or electricity price futures, and used to project future rates. Compound annual growth rates (CAGRs) could be derived for other billing determinants and applied to future years.

A review of historical Prices to Compare also helps convey the importance of forecasting net metering credits. For example, using ComEd residential (non-space heating) Prices to Compare as an example, year-over-year changes between January 2017 and May 2023 ranged from -8.6% to 63.1%. If limited to the period of January 2017 through December 2021 (i.e., excluding the price volatility of 2022) the observed range is -8.6% to 13.9%. Taking a multi-year view, the 4-year Price to Compare CAGR was 2.8% as of January 2021, the 5-year CAGR was 4.3% as of January 2022, and the 6-year CAGR was 7.3% as of January 2023. Assuming a 1% escalation on the total net metering credit throughout this period almost certainly underestimates net metering credits and over-estimates REC prices, at the expense of Illinois ratepayers.

If the results of a billing determinant-specific approach are not meaningfully different from the current methodology, it is nonetheless worth asking why this is the case and whether it is a short-term anomaly. After more than a decade of relative load stagnation (in aggregate), electrification initiatives abound. Total load growth over the next 15 years is unlikely to look like total load growth over the last 15 years. Therefore, energy and capacity market price dynamics for solar projects build under ABP and ILSFA during the 2024 – 2025 program year (the year to which these recommendations will be applied) are unlikely to bear much resemblance to energy and capacity market dynamics of the 2010s. In this context, an average 1% increase over the next 25 years would be an assumption, not a forecast.

We observe that, per the Bates White Comments on Electric Procurement Events Held Summer 2021-Spring 2022, the wholesale energy and capacity prices increased markedly after 2021, underscoring the potential benefits of a more detailed analysis.[30]

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

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.

The objective is to augment the cost-based approach with an adjustment that reflects market conditions. We maintain that the cost-based approach is the correct place to start, but non-cost factors may also impact program applications level and project deployment. The goal of this potential adjustment is to balance ratepayer impact with the achievement of MW targets. For example, if participation in a specified category and in a given year was to fall substantially short of its MW allocation, then the following year's cost-based REC price for that category would be adjusted upward to reflect the impact of non-cost factors on enrollment. This is effectively a *market protection mechanism* – intended to provide a REC price signal sufficient to maintain market participation following a low enrollment year that failed to meet targets. If the opposite were true, and deployment substantially exceeded targets, then the calculated REC price would be adjusted downward to reflect the expectation that MW targets could have been achieved with a somewhat lesser incentive. This is a *ratepayer* protection mechanism, intended to limit over-compensating generators on a risk-adjusted basis.

Again, as stated at the beginning of this recommendation, participation would need to fall either above or below a threshold relative to the annual category-specific target in order for an adjustment to occur. In other words, a moderate degree of over- or under-enrollment would not trigger *any* post-processing adjustment. And, as the annual cost-based incentive-setting process improves (due to data collection, stakeholder feedback, and other factors) we hope and expect that post-processing adjustments will be triggered less frequently – if at all.

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.

Recommendation 6: Refrain from Intra-Year Adjustments to REC Price Incentives

This review also evaluated the potential for intra-year REC price adjustments. Specifically, we considered *upward* REC price adjustments where current-year deployment was less than 50% of the annual block capacity at the mid-point of the applicable program year. For clarity, no *downward* REC price adjustments were proposed or considered. An intra-year REC price adjustment would have been intended to spur market response through a more immediate price signal than the annual REC price recalculation. Like the year-to-year adjustment, an intra-year adjustment would provide additional incentive for market participation when enrollment is significantly below the annual block allocation. Intra-year adjustments could also help account for non-price factors not captured in the current year's REC price.

Upon review, however, it became clear that specifying the timing and criteria for intra-year adjustments would be exceptionally challenging and potentially subject to manipulation. First, for reasons related to tax accounting, the development and financing process, and the construction schedule (especially at northern latitudes), the majority renewable energy projects are commissioned during the second half of the year. While the June-to-May program year may align reasonably well with capturing end of year calendar data before the program year ends, this would not necessarily translate well into projects being capable of responding to a new price signal in the last four or five months of the program year.

This option was considered as a potential mechanism to address limited deployment in a given year but given the fluidity of the development and component acquisition process, it is also possible that an intra-year price adjustment mechanism could *cause* deployment to be delayed into the end of the program year – in order to capture higher REC price incentives. As a result, this review recommends that Illinois policymakers refrain from adopting intra-year REC price adjustments.

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

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.

Broad Policy Implications of the IRA: As discussed throughout this Whitepaper, cost-based programs set incentive rates for a modeled project, which requires certain assumptions, which now must also account for the various ITC bonuses. Therefore, in order to ensure that these budget-limited programs can maximize their value in aiding Illinois in its efforts to reach its decarbonization targets, SEA recommends that REC prices in these programs should continue, as much as is possible, to be based upon actual project costs and realized tax benefits (the latter of which conveys a disproportionate share of the value of the project) of the resources deployed through the programs.

We recommend that the IPA require modeling of at least some permutations of bonus ITC values for projects. We 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. To accomplish this, SEA recommends that in setting REC prices, the IPA should ensure that it adopts a balanced compensation approach that ensures that projects that cannot qualify for certain bonuses are compensated sufficiently to be successfully deployed while simultaneously not compensating projects that *do* qualify for certain bonuses more than is necessary to achieve policy goals.

At the same time, however, it would not be reasonable or practical for the IPA to calculate all possible permutations of ITC value. Instead, SEA believes that it could be relatively simple for the IPA to request separate REC price calculations for the most common and/or likely permutations of ITC values that projects would qualify for, such as one ITC value at 30%, and another output if the ITC value is 40% (assuming that the project is eligible for one 10% bonus value), or one for 50% for ILSFA projects conveying "low income economic benefits," with REC incentive values adjusted accordingly. The additional costs of qualifying for a bonus, such as utilizing domestic content or developing a brownfield site, should be netted against the incremental value of the bonus credit to arrive at accurate levelized costs, and should reduce the differential between the bonus and non-bonus necessary REC values.[31] The principles deployed in this policy are that (a) Illinois DG and community solar projects require a REC incentive to be financially viable, and that (b) that Illinois ratepayers will fund REC incentives (up to a budgetary cap) based on the difference between after-tax LCOE and the levelized net metering credit. It is not clear to SEA that IPA has the latitude selectively exclude available ITC ('bonus' or otherwise) from the REC incentive calculation.

If policymakers wish to incent projects that qualify for bonus credits over those that do not (rather than provide the same rate of return for different permutations), SEA believes there are administratively efficient ways to accomplish such a task. For example, the IPA could create specific project classes or sub-classes with separate capacity allocations for projects able to monetize these credits, or otherwise prioritize review of such projects in the project qualification process, rather than by allowing project owners to earn disproportionate returns at the expense of ratepayers.

We acknowledge the comments from the JSPs and the JNGOs that holding approximate rates of returns equal across different ITC Bonus permutations means that project owners may be indifferent as to whether the projects claim a bonus credit. If policymakers deem it appropriate and beneficial for Illinois ratepayers to fund a REC incentive greater than that required on a cost basis, mechanisms are available to accomplish this goal. For example, the net incremental value of a bonus credit (after incremental costs of qualification are accounted for), could functionally be split between Illinois ratepayers and project owners by reducing the modeled bonus ITC by a specified percentage. This would allow for multiple parties to see benefits from bonus ITC projects, without benefits accruing exclusively to project sponsors.

Though we believe that program simplicity is an important policy goal, such simplicity would, in this instance, conflict with other goals such as modeling accuracy and cost-effectiveness. We do not believe it would be overly complicated to provide an additional set of outputs for the most common ITC bonus permutations given the potential impact on REC prices and/or project owner returns. That said, SEA believes that the lack of final implementation guidance from the federal government on several aspects of bonus credits introduces uncertainty for modeling purposes. Thus, the fact that the recommendations of this Whitepaper, if adopted, would not be implemented until the 2024-2025 Program Year, is fortuitous timing given the current pace of IRA bonus credit implementation. This is especially true given that there will almost certainly be guidance on qualification for bonus credits that is sufficient for modeling purposes by the time the 2024-2025 REC price-setting process is underway.

Baseline Assumptions: SEA recommends the IPA develop policy that encourages project developers to take reasonable steps to qualify for bonuses that are economical to claim. By "economical to claim" we mean that, after sufficient federal guidance, the incremental costs of qualifying for the credit are less than or equal to the incremental value to the project owner. Some bonuses to the ITC, such as the prevailing wage requirements, are already substantively required by Illinois law and program rules.[32] Other straightforward implications that are not as subject to uncertainty, such as including interconnection costs in the ITC basis, should also be incorporated into the cost modeling by default for all projects. (Interconnection costs do not apply to the § 25D credit for individuals.) Similarly, with the Direct Pay provisions of the IRA, and the transferability option, tax-exempt entities should be modeled as able to monetize the ITC if, after final guidance on the implementation of the provision, it would be economical to claim.

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.[33] 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.

Another potential means to align federal and state policy would be the creation of sub-categories eligible project that would, by definition, qualify (though not necessarily be selected to receive) certain ITC values. By way of example, there could be a separate bin for brownfield projects that would qualify for the brownfield ITC adder, which would allow for cost-based modeling of brownfield solar projects in particular, which would include both incremental costs specific to brownfields, as well as the 10% ITC bonus for such projects. Thus, a project in this category would neither be penalized for accepting federal incentives, nor would the project capture excess value beyond the rate of return already included in the modeled discounted cash flow.

The ILSFA program rules are well-placed to potentially qualify for the low-income adders. The adders are potentially available to households that either earn below 200% of the Federal Poverty Line (FPL) or have less than 80% of area median income (AMI). The ILSFA eligibility guidelines already state that 80% AMI is the eligibility threshold for single-family households, however multi-family housing is eligible for ILSFA with a mix of incomes above and below 80% of AMI. We note that, as described in Appendix F of the 2022 Plan, 200% of the non-farm FPL has a large overlap with 80% AMI (namely, for the large majority of households with less than 6 people).[34] The ILSFA also already has shared savings requirements. However, we note that qualification for the bonus credit is dependent on selection by the Treasury under a process that is not yet finalized, and, as noted above, limited the 1,800 MW each year (allocated between the different categories) for years 2023 and 2024.[35] Therefore, while the bonus could be a substantial benefit, it is unclear whether, and how much ILSFA project capacity might qualify.

While there are implementation questions that are best addressed in a broader stakeholder process, a mechanism to differentiate between projects that do and no not claim various bonus credits could take the shape of a self-attestation form in which a ABP or ILSFA applicant indicates which permutation of the ITC the project would claim. If such a measure is adopted, strong enforcement mechanisms, such as a claw-back for improper reporting, are necessary to ensure compliance.

Similarly, SEA would recommend that, in the unlikely event of the repeal or substantial alteration to the bonus credit values by Congress or the Department of the Treasury/Internal Revenue Service (IRS) in the future, that projects can have their REC values recalculated to ensure they do not structurally fall short of their required revenue to cover project costs plus a reasonable rate of return.

Longer-Term Legislative Consideration: Adoption of Strike Price or Bundled Standard Offer approach for large projects

The recommendation to consider a strike price approach to REC price setting is intended to align with the objective of balancing ratepayer impact and market participant returns. A strike price is designed to compensate each project at its category specific revenue requirement. The strike price is set at the LCOE for each category. The REC price paid is the difference between the strike price and the actual net metering credit – a net metering credit forecast would no longer be necessary. The strike price approach allows projects to seek financing based on a utility tariff that guarantees its full revenue requirement. This reduces project risk and is expected to lower the cost of capital – which will lower the LCOE and thus total REC payments, all else equal. The total cost to Illinois ratepayers of achieving ABP and ILSFA deployment targets is therefore likely lower under the strike price approach. This approach is best paired with the 20-year, pay-as-you-go contract structure. Therefore, a pilot program – if deemed appropriate – could be conducted with Traditional Community Solar and Public School projects, but would likely require legislative authorization.

With respect to programmatic cash flows and budgets, however, there is less certainty. While overall project revenue is fixed, a temporary reduction in energy prices would translate into a temporary increase in REC prices. The energy price volatility observed since 2021 suggests that temporary reductions in energy prices could reasonably be expected in the mid-2020s. It is equally true, however, that electrification and the associated increase in load could lead to mid- and long-term electricity price increases that significantly outpace the 2010s and outpace the one percent annual escalation rate currently applied to net metering credits. Under a strike price approach, electricity price (and therefore net metering credit) increases would be offset by REC price decreases on a $/MWh basis – thus preserving the category specific revenue requirement. It is also possible that the net metering credit could reach parity with, or exceed, the fixed revenue requirement. Under this condition, the REC price would be zero (or potentially negative), and it would be inappropriate for Illinois ratepayers to make payments for RECs when the market value of solar production exceeds the project revenue requirement, especially after having guaranteed projects their revenue requirement in all prior years.

SEA does not recommend adopting a strike price for residential or small commercial projects.

Conclusion

This REC pricing policy review is intended to spur and support a dialogue between policymakers and market participants and explore new policy mechanisms that balance the interest of Illinois ratepayers and the renewable energy development community. The recommendations herein are intended as a starting point for discussion during the Long-Term Plan process. Supplemental analysis and stakeholder feedback may be beneficial in some areas. Ultimately, the aim of this Whitepaper is to support informed decision making for the benefit of Illinois' ratepayers and renewable energy marketplace.

Appendix A: Variance in Risk-Adjusted Equity Rates of Return Related to Policy Design

In cost-based incentive development, the objective function is to ensure compensation is equivalent to a project's costs (including debt interest expense, if applicable) plus a risk-adjusted equity rate of return. The components of this risk-adjusted rate of return are tax equity (comprised of capital invested by recipients of the majority of federal tax credits and depreciation benefits, and a minority of cash flows) and sponsor equity (sometimes referred to as "cash equity"), which receives the minority or tax benefits and majority of cash benefits. A "risk-adjusted" return refers to the impact of policy design on revenue certainty for equity providers. For example, a project that is compensated entirely via net metering credits (which do not have a fixed value that the financier can rely upon) will require a higher risk-adjusted rate of return than a project that is compensated through fixed payments for both energy and RECs – as in a "feed-in tariff," standard offer, or other all-in cost-based incentive. The longer the revenue certainty, and the greater the percentage of revenues hedged, the lower the risk. The rate of return has a significant impact on the overall cost of projects to ratepayers.

For illustration, Table 6 provides an example of how sponsor and tax equity internal rates of return (IRRs) combine to create estimated risk-adjusted returns for a 500 kW building mounted project qualified in Rhode Island's current net metering program, and the same sized project qualified in the Renewable Energy Growth (REG) program. In the first case (net metering) no attributes are purchased by the utility (and therefore the project's revenue remains unhedged), while in the second case (REG) the project's energy, capacity, and REC revenues are fully hedged. Due to repayment priority and allocation of benefit, the majority of the increased risk typically falls on sponsor equity provider.

Table 6 Comparison of Assumed Equity Internal Rates of Return by Policy Type

Case Description	500 kW Building Mounted Solar PV (Net Metering)	500 kW Building Mounted Solar PV (Renewable Energy Growth)
Tax Equity Share of Total Equity	66.7%	66.7%
Tax Equity IRR	9.5%	9.5%
Sponsor Equity Share of Total Equity	33.3%	33.3%
Sponsor Equity IRR	15%	12%
Consolidated Equity IRR	11.33%	10.33%

The risk profile associated with the ABP and ILSFA programs likely falls within this range. For projects receiving REC prepayments, the risk is lower and – all else equal – would likely be closer to the lower end of this range.

Endnotes

[1] 22-0231 Order, page 80
[2] https://illinoisabp.com/
[3] https://www.illinoissfa.com/
[4] 20 ILCS 3855/1-75(c)(1)(K)
[5] 20 ILCS 3855/1-75(c)(1)(K)
[6] 20 ILCS 3855/1-75(c)(1)(K)
[7] 20 ILCS 3855/1-75(c)(1)(K)
[8] 20 ILCS 3855/1-56(b)(2)
[9] 20 ILCS 3855/1-56(b)(4)
[10] 20 ILCS 3855/1-56(b)(4)
[11] 20 ILCS 3855/1-56(b)(3)
[12] https://ipa.illinois.gov/content/dam/soi/en/web/ipa/documents/ipa-equity-factsheet-92722.pdf
[13] 20 ILCS 3855/1-75(c)(1)(K) & 20 ILCS 3855/1-56(b)(2)
[14] 20 ILCS 3855/1-75(c)(1)(K)
[15] The program features a soft price floor (via a yearly auction) to incent all SREC to be purchased at the end of a compliance year
[16] https://www.mass.gov/info-details/net-metering-eligibility
[17] https://www.mass.gov/doc/post-400-mw-solar-policy-development-presentation/download
[18] https://www.nyserda.ny.gov/All-Programs/NY-Sun/Contractors/Value-of-Distributed-Energy-Resources
[19] https://energy.ri.gov/renewable-energy/wind/renewable-energy-growth-program-reg-program
[20] In the interest of full disclosure, Sustainable Energy Advantage consults for the Rhode Island Office of Energy Resources in the REG program Ceiling Price development process
[21] https://energy.ri.gov/renewable-energy/solar/distributed-generation-board
[22] https://www.mass.gov/info-details/solar-massachusetts-renewable-target-smart-program
[23] https://www.mass.gov/doc/smart-launch-and-program-overview/download
[24] Sections 8.5.3.3 and 8.5.3.4 of the 2022 LTRRPP https://ipa.illinois.gov/content/dam/soi/en/web/ipa/documents/2022-long-term-plan-23-august.pdf
[25] https://www.illinoissfa.com/app/uploads/2023/04/Residential-Pilot-AV-RFP_2023.04.07-FINAL.pdf
[26] Section 8.5.6.1 of the Plan https://ipa.illinois.gov/content/dam/soi/en/web/ipa/documents/2022-long-term-plan-23-august.pdf
[27] https://www.icc.illinois.gov/docket/P2022-0231/documents/326113/files/567658.pdf
[28] Page 95 of the 22-0231 Order https://www.icc.illinois.gov/docket/P2022-0231/documents/326113/files/567658.pdf
[29] Cell C4 of the "Net Metering Credit" tab https://view.officeapps.live.com/op/view.aspx?src=https%3A%2F%2Fwww.levitan.com%2Fillinois%2FREC%2520Pricing%2520Model_20220726_Post%2520ICC%2520Filing.xlsm&wdOrigin=BROWSELINK
[30] https://www.icc.illinois.gov/programs/Electricity-Procurement-Process-for-Plan-Years-Beginning-June-2022
[31] In recent months, SEA has been involved in several such cost-based modeling efforts in Maine and Rhode Island that utilize this approach (netting incremental capital and/or operating costs associated with projects that can receive bonus tax credits). For more, see Synapse Energy Economics, Inc. and Sustainable Energy Advantage, LLC (on Behalf of the Maine Governor's Energy Office (GEO). *Distributed Generation Successor Program in Maine: An Economic Assessment.* 6 January 2023. Available as an Appendix to: https://legislature.maine.gov/doc/9388.
[32] We note that the IRA uses Davis-Bacon prevailing wages, and CEJA pegs prevailing wages to the IL Department of Labor prevailing wage standards. However, for many if not all job types, the state prevailing wages appear to be slightly higher.
[33] The IRA allows eligible taxpayers to request a waiver from the requirements if the project costs increase the total cost of the project by more than 25% (see 26 U.S.C. § 45(b)(10)(D), which also applies to the § 48 ITC and the § 48E Clean Energy Investment Credit (CEIC).
[34] https://ipa.illinois.gov/content/dam/soi/en/web/ipa/documents/appendix-f-ilsfa-income-levels-2022-long-term-plan.pdf
[35] https://www.irs.gov/pub/irs-drop/n-23-17.pdf