Stakeholder Response

Illinois Power Agency — Request for Information #1 on Development of the Storage for All Program

Submitted by	Solve: Resource and Energy Associates (lead respondent), with Valuestack (contributing partner — storage and ownership-structure content)
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Confidentiality	This response contains no confidential information and may be posted publicly in its entirety.

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About the Respondents

Solve: Resource and Energy Associates is a consulting, professional services, and staffing firm that helps businesses and public-sector organizations accelerate clean energy adoption, with a particular focus on affordability, project finance, alternative ownership, and innovative business models. Drawing on decades of combined experience in clean energy and structured finance, Solve has developed low-cost and no-money-down offerings for low- and moderate-income customers and pioneered first-of-a-kind financing programs for emerging asset classes, including distributed wind, community solar, building decarbonization, air-source heat pumps, electric vehicles and charging infrastructure, and energy storage. Our work includes project finance, third-party ownership, tax-credit and incentive structuring, and advising policymakers on programs that make clean energy more affordable and accessible. In Illinois, Solve's team has extensive experience supporting building decarbonization in low-income communities and has participated in solar development and financing efforts. We are currently supporting the commercialization and financing strategy for a residential-scale battery product targeting Illinois as a primary market. The technology is designed to dramatically reduce battery storage costs for residential and small commercial customers, while our financing and ownership strategies aim to make adoption accessible with little or no upfront cost.

Valuestack is an energy-transition consultancy that builds custom solar + storage dispatch and value-stack models for developers, IPPs, utilities and software companies in PJM, NYISO, ISO-NE, CAISO, ERCOT and international markets, with a focus on making state incentive programs, utility tariffs and VPP/demand-response rules show up correctly in project economics. Valuestack contributed the storage, ownership-structure and program-integration portions of this response. We appreciate the Agency's early engagement and the transparency of Appendix A, and offer these comments from the perspective of parties who would develop, finance or advise on Storage for All projects.

Summary of Recommendations

1. **Budget (Q1–2).** Target the full 25% allocation (~$7.6 million) in year one, with consideration of a larger allocation if permitted and warranted, released in tranches with a mid-year reallocation point so uncommitted funds return to waitlisted ILSFA solar projects.
2. **Mechanism (Q6).** A one-time $/kWh incentive with a per-project cap tiered by subprogram, paid in full at storage energization through the existing ILSFA contract and payment infrastructure, with VPP enrollment as a condition — not an ongoing REC adder.
3. **Rate-setting (Q6, Q14).** Set the $/kWh rate annually through a transparent storage incentive price model, based on fully loaded project economics after eligible utility rebates, realistically monetizable federal tax credits, and risk-adjusted—not guaranteed—VPP revenues.
4. **Integration (Q3).** Two pathways — integrated solar + storage applications for new ILSFA projects, and a capped retrofit pathway for energized ILSFA systems — both verified at Part II.
5. **Linkage (Q7).** Keep the solar REC contract unaffected if storage is dropped; attach consequences to the storage component only.
6. **No upfront cost and the 50% test (Q9, Q11).** Prioritize zero upfront customer cost, meaningful net household savings, resilience and strong consumer protections. Zero ongoing payments should be encouraged where feasible, while carefully structured third-party-owned offers with transparent positive net benefits should remain eligible, subject to applicable program requirements.
7. **Appendix A (Q1.1–1.2).** Installed-cost assumptions are a useful starting point, but the ~$10,000 cost-to-incentivize estimate excludes potential third-party-owner ITC proceeds and enabling electrical costs. Indicative residual incentive figures must also account for tax-credit monetization discounts, developer soft costs, financing and structuring expenses, O&M, reserves and required project returns before determining bankable incentive levels or likely project counts.

Program Funding (Questions 1–2)

Q1 and Q2 — Recommended starting percentage

We recommend targeting the full 25% initial allocation, or a larger allocation if permitted and warranted, released in tranches for three reasons:

- The statute protects ILSFA solar by allowing uncommitted Storage for All funds to flow back to waitlisted or unfunded ILSFA projects. A substantial initial allocation, coupled with a defined reallocation trigger (for example, funds uncommitted by month nine of the program year returning to the ILSFA pool), would give the market a credible signal without stranding money. An allocation that is too small may not justify Approved Vendors investing in storage design, product approval, installer training and financing relationships ahead of launch.
- Per-project incentive needs should be established through fully loaded sources-and-uses and lifecycle cash-flow modeling, not simply installed cost less face-value incentives. Qualified third-party owners may claim Section 48E credits subject to applicable eligibility rules, but these credits are not equivalent to cash at face value. For smaller residential projects, approximately 80% of credit face value is a prudent illustrative net-monetization assumption, before the developer's additional costs of arranging the transaction. Attachment A's figures should therefore be treated as preliminary, not verified estimates of a financeable subsidy or supported project count.
- **Year-one uptake will be constrained by process, not budget** — approved product lists, storage interconnection, AV readiness and customer education. A tranche structure (for example 60% at program-year open, 40% at mid-year if commitments warrant) accommodates the ramp without idle funds.

The full 25% allocation should be the target rather than a ceiling to negotiate downward. Any alternative should be justified by deployment readiness and still be sufficient for both meaningful residential deployment and facility-scale resilience projects. Comments on Appendix A assumptions (Q1.1–1.2) appear in Attachment A.

Integration with the Illinois Solar for All Program (Question 3)

Q3 and Q3.1 — Two pathways, one set of verification rules

- **Pathway A — new projects, solar + storage together.** Storage should be an optional component of the ILSFA Part I application, not a separate application. The project is selected through the existing ILSFA process; if selected, the storage component is funded from the Storage for All budget. This avoids a second lottery, keeps one customer agreement and one disclosure form, and lets the AV design the system (hybrid inverter, critical-loads panel) once. It should be the primary pathway: integrated installations are typically 15–25% cheaper per kWh than retrofits.
- **Pathway B — retrofit of energized ILSFA systems.** A short, rolling application for existing participants (expressly eligible under the statute): existing system data, proposed battery, interconnection approval, verification at commissioning. Cap Pathway B at a share of the annual budget (for example 30–40%) so the cheaper integrated pathway is not crowded out, and prioritize sites where the existing inverter supports AC coupling without replacement.
- **Both pathways** should verify storage at Part II with storage-specific documentation: commissioning report, utility interconnection approval for the storage system, VPP enrollment confirmation where a program is open to the product, and the customer disclosure.

Q3.2 — Existing processes to respect

- **REC payment timing.** Existing REC payment schedules may differ across Illinois Shines and Illinois Solar for All contracts; the applicable schedule for ILSFA Residential Solar (Small) should be confirmed. If a storage incentive followed a multiyear REC payment schedule rather than being paid at storage energization, Approved Vendors and financing partners could incur additional carrying costs that ultimately reduce customer benefits or constrain participation. We therefore recommend that the Storage for All incentive be paid in full at storage energization, independently of the solar REC payment schedule, to the extent permitted by program rules.
- **Storage produces no RECs.** A REC-denominated storage incentive would be tied to solar output rather than storage capacity or performance and would need to be translated into a size-dependent $/REC adder — an unnecessary layer (see Q6).
- **Storage interconnection can lag solar.** Let the solar portion energize and be paid on its own schedule, with the storage payment following storage commissioning within a defined window (for example 12 months).

Program Focus (Questions 4–5)

Q4 — A baseline for all projects; community resilience concentrated in the facilities subprogram

We recommend a baseline rather than a single focus: every system should deliver both a bill benefit and household or facility resilience. For a residential system the same battery does both, and the design choices that distinguish them are small (a critical-loads panel, a backup-reserve setting). Focus areas are better expressed as design and participation requirements — minimum backup reserve, VPP enrollment where available, a critical-loads panel for households with medical equipment — than as competing selection categories. Community resilience and disaster preparedness are most meaningful in the nonprofit and public-facilities subprogram, where one larger system at a cooling or warming center, shelter, clinic or food pantry serves many households; we recommend a dedicated budget share (for example 20–30%) so residential volume does not consume it.

Q5 — Objective scoring in the facilities subprogram; eligibility rules for residential

In the nonprofit/public subprogram, apply a scored adder on verifiable criteria rather than narrative: location in an environmental justice community under the Agency's existing designation; formal designation by a county or municipal emergency-management agency as a shelter, cooling/warming center or similar; and defined critical loads (refrigeration, medical equipment, communications). For residential projects, use eligibility or priority rules — for example, priority for medical-needs households and for customers on circuits with above-average outage duration — which are simpler to administer consistently across AVs than scoring.

Rebate, Grant or Other Incentive Mechanism (Questions 6–8)

Q6 — A one-time, capacity-based incentive paid at energization, not an ongoing REC adder

Specifically: a $/kWh rate on usable capacity up to a per-project cap, with separate tiers for Residential Solar (Small), multifamily, and nonprofit/public facilities, paid through the existing ILSFA REC contract and payment infrastructure as a separately identified storage payment, so no new counterparty or payment system is needed. Our reasons:

- **Zero upfront customer cost requires financeable upfront proceeds.** Approved Vendors and financing partners fund installation and enabling work before long-term revenues are realized; spreading an incentive over years increases working capital needs and financing costs and can exclude smaller providers. Predictable, assignable payments at energization, standardized documents and clear payment timelines can reduce risk premiums and enable more affordable third-party-owned offerings.
- **A $/kWh rate is transparent** — easy to disclose to the customer, to compare across AVs, and to check against other incentives (Q14). Storage has no RECs to attach an adder to.
- The rate can be reviewed annually through a transparent storage incentive model with public assumptions for installed and enabling costs, realistic net ITC proceeds, utility rebates, risk-adjusted VPP value, operating and replacement reserves, financing and structuring expenses, and cost of capital. Future VPP cash flows should not be treated as interchangeable with certain upfront incentive proceeds.
- **Performance should be bought from the utility programs built for it.** ComEd's Scheduled Dispatch VPP (ICC-approved, launching 2027) and its Ameren counterpart already pay for dispatch. Storage for All should require VPP enrollment where a program is open to the product, and reserve the right to recover the incentive if the system is removed or the AV terminates the agreement within the first five years, rather than paying for performance twice.

If the Agency wants a performance element, a hybrid works: 85–90% at energization and 10–15% at a 12-month check confirming operation and enrollment. Connecticut's Energy Storage Solutions program — an upfront $/kWh incentive ($600/kWh for low-income customers) plus utility-paid performance incentives — is the closest working precedent and appears in the CESA materials the Agency cited.

Q7 and Q7.1 — Plan for storage drop-outs; keep the solar contract whole

Storage will be dropped in a meaningful minority of projects — site constraints (no suitable location, panel capacity, flood-prone basements), product availability, interconnection outcomes, or customer choice — and the program should plan for it rather than penalize it heavily. The solar REC contract should remain unaffected: if storage is dropped before storage commissioning, the storage allocation is released back to the pool (and ultimately to the ILSFA waitlist), the solar project proceeds under its ILSFA contract, and the customer's solar benefit is untouched. Putting the solar incentive at risk would raise the risk premium on every ILSFA project, ultimately at the customer's expense. Consequences should attach to the storage component only: (i) forfeiture of a modest storage-specific collateral if the drop occurs after a defined date; (ii) if storage earned a selection preference (Q5), loss of that preference on the AV's next application; (iii) tracking of AV drop rates, with high rates triggering review. Removal after energization should trigger pro-rata recovery of the storage incentive.

Q8 — Opportunities and challenges of the recommended approach

Opportunities: compatibility with the existing ILSFA no-cost lease model and payment system; clear stacking arithmetic; an annual price model that tightens the rate as costs fall; and alignment with utility VPP programs that launch in 2027, a year ahead of Storage for All. Challenges: (a) ITC availability is not uniform — Section 48E applies to third-party-owned systems and, for storage beginning construction after 2025, is subject to foreign-entity-of-concern "material assistance" rules that some residential battery products may not satisfy; the price model should be set for the ITC-eligible case, with an approved-product list that confirms compliance, and revisited annually; (b) a payment at energization needs recovery provisions for early removal; (c) battery warranties (typically 10 years) are shorter than ILSFA solar lease terms, so the customer agreement must address end-of-warranty replacement or removal at no cost to the customer. A REC adder would avoid (b) but adds financing cost, ties the storage payment to solar output and is harder to reconcile with other incentives. From a project finance perspective, predictable and assignable incentive payments, standardized ownership and customer agreements, clear allocation of incentive and grid-service revenue, and defined ongoing asset obligations are essential to bankability. An illustrative goal is to enable unlevered project IRRs below 15%, potentially approaching 10% as portfolios scale and financing becomes standardized; these are not proposed return caps. Higher unlevered returns may be needed for small or early-stage portfolios with substantial financing, tax-credit monetization and transaction structuring costs. The

Agency should clarify whether the program's primary objective is energy-bill savings, access to resilience, or both, and how these benefits will be evaluated.

Ensuring No Upfront Costs and Understanding Customer Benefits (Questions 9–13)

Q9 — Zero upfront cost

- **Include enabling costs.** Storage in older housing stock frequently requires a main-panel upgrade, a critical-loads subpanel or electrical remediation ($1,500–4,000 per site is common). Unless the incentive covers these explicitly, they become a customer charge or the reason an AV drops storage; we recommend an enabling-cost allowance within the per-project cap.
- **Pay at energization and allow assignment** to the AV's financing partner, as ILSFA REC payments are today. Small and emerging AVs may need a milestone payment at installation where permission-to-operate for storage lags.
- Prioritize no upfront customer cost, meaningful net savings, resilience benefits and transparent consumer protections. Providing storage with no ongoing customer payments is desirable and may be feasible for some projects, but should not automatically be the only eligible model if carefully structured ongoing payments still leave substantial net household benefits. Customer disclosures should show total payments, projected bill savings, grid-service compensation, backup-power capabilities and end-of-term obligations. Eligibility should avoid FICO-based barriers; the Agency should explore participation for renters and individually metered multifamily tenants, including emerging plug-in systems where permissible.
- **Keep the customer whole at end of term:** the agreement should specify replacement, transfer in working condition, or removal at no cost at battery end-of-warranty or end-of-lease.
- **Coordinate with workforce programs:** a storage commissioning and VPP-enrollment module within the existing Clean Jobs Workforce Network and Approved Vendor training is a low-cost way to meet the statute's job-training requirement.

Q10 — Quantify benefits with one standardized method

We suggest three benefit categories, each with a defined quantification, applied through a simple calculator published by the Agency or Program Administrator so results are comparable across applications (Valuestack would be glad to contribute to its design): **(1) Bill benefit**, modeled hourly from site solar production, a representative subprogram load profile and the applicable supply and delivery tariff — including the shift away from full retail net metering for new distributed generation, time-of-use delivery rates and peak-load-contribution effects — reported as annual dollars and change in energy burden; **(2) Reliability benefit**, expected avoided outage hours from utility reliability data (SAIDI/CAIDI by region or circuit) and the system's backup duration for a defined critical load, optionally valued with a standard customer-interruption-cost method; **(3) Preparedness and community benefit** (facilities), critical-load coverage hours for the designated function and residents served. For prioritization: bill benefit and household reliability as the baseline every residential project must meet; community benefit as the priority criterion in the facilities subprogram.

Q11 and Q11.1 — Protecting and augmenting the 50% savings requirement

- **Residential Solar (Small):** prioritize zero upfront payment and strong, measurable net customer benefits, rather than assuming that a zero-payment arrangement is the only viable third-party-owned structure. Zero ongoing customer charges should be encouraged where financing and incentive support permit. Where charges are allowed under applicable program requirements, disclose and test all customer payments against combined savings, protect the existing solar benefit, and avoid FICO-based underwriting barriers. The Agency should clarify how household resilience benefits are recognized alongside bill savings.
- For multifamily, nonprofit/public and any residential arrangements where storage service charges are permitted, apply a transparent combined net-benefit test: solar and storage bill benefits and customer-attributable grid-service compensation, less all customer payments, must satisfy the applicable savings requirement. Separate projected monetary savings from resilience benefits rather than silently assigning a speculative dollar value to backup power. Incentive and financing structures should seek to direct ongoing economic value to participating households while providing asset owners the contracted revenues necessary for financeable, reasonable risk-adjusted returns.
- **Define the denominator for solar + storage.** Under the current compensation structure for new distributed generation, on-site consumption is worth more than export; storage shifts output into on-site use and can raise the realized value of the solar energy. The Agency may wish to state whether "value of energy produced" is measured on an export-weighted or retail basis for paired projects.

Q12 — Cost data

We provide indicative market-based installed-cost ranges rather than verified Illinois-specific installation quotes. Indicative installed costs before incentives: residential storage retrofitted to an existing system, $1,000–1,300/kWh; residential storage installed with new solar (hybrid inverter, shared labor and permitting), $800–1,100/kWh; enabling electrical work where required, $1,500–4,000 per site; larger systems for multifamily and nonprofit/public facilities (30–150 kWh), $600–900/kWh. These estimates are broadly consistent with Appendix A's $950–1,300/kWh range and should be refined as Illinois-specific installation data becomes available.

Q13 and Q13.1 — Benefits data; interaction with the Low-Income Discount Rate

Solve can discuss anonymized observations from comparable low-income clean-energy financing programs, including customer savings, ownership structures and financing costs, subject to data availability and client confidentiality. The Agency should distinguish net household benefits from asset-owner cash flows, including how VPP value reaches customers. On Q13.1, customer benefits attributable to storage should be transparent and measurable through the storage offering itself, including bill savings, any customer compensation from grid services, and resilience benefits. Existing utility bill discounts are separate affordability mechanisms and should not obscure whether the storage system delivers meaningful additional value to the participating household.

Avoiding Double Counting of Incentives (Questions 14–15)

Q14 — Distinguish stacking from double payment

Stacking is appropriate where different funders pay for different attributes: the utility rebate for grid value under the DG rebate tariff; VPP payments for dispatch; the federal ITC as federal policy; the ILSFA REC price for solar access; and Storage for All for the residual needed to make storage accessible at zero upfront cost. Double payment occurs when the same cost is covered twice. Three safeguards: (1) size the Storage for All rate as the residual after known stackable sources through the annual price model (Q6), with a project-level sources-and-uses required as a disclosure but not negotiated project by project; (2) keep solar and storage costs separate in the ILSFA REC price model, so neither incentive implicitly covers the other; (3) require transparent disclosure of all incentives and grid-service revenue, including how the benefits are shared between the customer and third-party owner. The structure should seek to maximize grid value, fairly compensate the owner for financing and operating the battery, and deliver substantial customer savings and resilience benefits. Where incentives and grid-service value permit, an offer with no customer payments remains the preferred outcome.

Q15 — Assumptions about other funding sources (subject to eligibility and periodic review)

- Utility DG rebate: An illustrative $300/kWh rebate for qualifying storage under 100 kW in ComEd and Ameren territories is assumed for purposes of the model; actual availability, participation requirements, applicable tariffs and payment timing should be confirmed for each project.
- VPP: ComEd's Scheduled Dispatch VPP is described as providing $10/kW per summer season for five seasons (subject to program terms), with an Ameren counterpart. The illustrative ~$270 over five seasons is nominal, not an upfront or guaranteed financeable receipt. Other possible sources of ongoing storage value, including arbitrage and metering-related compensation, require clearer definitions and verification of eligibility, dispatch assumptions, customer tariffs and payment arrangements. Solve has encountered widely varying preliminary estimates of approximately $100 to $1,000 per year for a residential 60 kWh system; these are anecdotal scenario estimates, not verified program payments and should not be extrapolated to the smaller reference system. The Agency should publish transparent revenue assumptions and sensitivities so financiers and customers can evaluate the uncertainty.
- Federal ITC: A 30% Section 48E credit may be available for eligible third-party-owned storage projects, subject to applicable tax, equipment, and foreign-entity restrictions. Additional bonuses can bring the nominal credit to 40% and, in some qualifying cases, 50%; neither bonus should be assumed as a default in program underwriting. Availability of each increment depends on the specific project's eligibility and the rules in effect. The economic value to the owner also depends on monetization: for small residential portfolios, model an illustrative 80% realization of credit face value before additional developer transaction and structuring costs, with scenarios for ineligibility or less favorable monetization.
- Other: accelerated or bonus depreciation for taxable third-party owners; no federal grant funding (EPA Solar for All awards were terminated) and no federal home-energy rebate applicability to batteries; zero-upfront-cost customer offerings, with any permitted ongoing service charges subject to transparent net-savings tests and strong consumer protections.

Attachment A — Comments on Appendix A Assumptions (Questions 1.1 and 1.2)

Appendix A data point	IPA figure / assumption	Comment
Reference system size	13.5 kWh / 11.5 kW (Tesla Powerwall 3)	Reasonable as a conservative reference, but larger than most single-family ILSFA homes need Actual reference sizing should reflect typical Residential Solar (Small) customer needs; a 10 kWh unit covers typical critical loads overnight. Suggest modeling 10 and 13.5 kWh and setting the cap by usable kWh rather than by one product.
Installed cost	$950–1,300/kWh; median $1,125; ~$15,187 per system	Consistent with 2026 marketplace data. Integrated installations with new solar run lower (shared labor, permitting, hybrid inverter); AC-coupled retrofits sit at the upper end. Add enabling electrical costs ($1,500–4,000 where needed), common in ILSFA housing stock.
Cost to incentivize	~$10,000 (installed cost less ~$4,000 rebate less ~$270 VPP)	Omits the federal ITC available to third-party owners (≈30% of basis, ≈$3,300–4,500 on a 10–13.5 kWh system). Nets VPP at undiscounted five-year value. Omits AV cost of capital, monitoring/O&M and a replacement reserve. ~$10,000 is a reasonable non-ITC case; with the ITC, the residual is roughly $5,000–7,000 (below).
Average ILSFA project	18 kW AC; $53,585 incentive	Cross-subprogram averages are skewed by facilities. Use subprogram-specific medians for storage sizing and for the "solar projects displaced" comparison.
Projects per $7.6 million	~142 solar via ILSFA; ~700 storage	The ~700 figure assumes all residential and no ITC. All-residential with the ITC: roughly 1,100–1,400 systems. A mix including facility systems changes the count modestly.
Utility rebate	$300/kWh, ComEd and Ameren	Agree. Confirm participation conditions and availability to third-party owners.
VPP	5.4 kW × $10/kW × 5 years ≈ $270	Agree with the rate. The ComEd program begins in 2027 and requires five consecutive summer seasons; align the customer agreement term and dispatch settings with it.

Illustrative sources-and-uses — 10 kWh residential system, third-party-owned (approximate)

Item	With ITC	Without ITC	Basis
Installed cost (10 kWh × $1,100/kWh)	$11,000	$11,000	Appendix A range
Enabling electrical allowance	$1,500	$1,500	Panel / critical-loads work
Less: utility DG rebate (10 kWh × $300)	($3,000)	($3,000)	ComEd / Ameren tariff
Less: federal ITC (30% × $11,000)	($3,300)	—	Section 48E, third-party owner
Less: VPP value (5 seasons, discounted)	($200)	($200)	ComEd SDVPP, $10/kW-season
Residual Storage for All incentive need	≈ $6,000	≈ $9,300	Before AV margin and cost of capital
Systems supported by $7.6 million	≈ 1,250	≈ 800	Budget ÷ residual
Note: the ITC case assumes a product that satisfies the foreign-entity material-assistance rules and an owner with tax capacity or a transfer counterparty; where either is uncertain, the non-ITC case is the planning basis. The effect of utility rebates on eligible ITC basis depends on the applicable tax treatment and should be modeled accordingly.			

Solve financing qualification (Attachment A): The 10 kWh sources-and-uses and resulting project counts are simplified illustrations, not fully underwritten incentive requirements or guaranteed deployment estimates. The table uses face-value ITC proceeds and does not fully account for monetization costs, financing and legal structuring, ongoing O&M, replacement reserves, or required project returns. Sensitivities should assume approximately 80% realization of nominal ITC value for small residential portfolios before additional developer transaction costs. A workable third-party-owned offering may also rely on limited, affordable customer payments and meaningful but uncertain ongoing storage or grid-services revenues;

those elements should be modeled transparently alongside no-payment scenarios. Actual subsidy needs and numbers of supported projects will depend on system size, eligible incentives, cost of capital, customer benefits and program rules.