[Commenter 3]
Comments on Draft ISC Contract and Preliminary Proposal Requirements

From: [Commenter 3]
Sent: Mon 6/15/2026 12:43 PM
To: Illinois-RFP <Illinois-RFP@nera.com>
Subject: Summer 2026 Energy Storage RFP - round 2 comments

Dear NERA team,

Please find attached our latest comments to the round 2 of questions for the Illinois Summer 2026 Energy Storage RFP.

Best,

[Commenter 3]

[redacted]

[redacted]

June 15, 2026

Submitted Electronically to Illinois-RFP@nera.com

TO: Program Administrator of the Illinois Power Agency's Summer 2026 Energy Storage RFP

RE: **Summer 2026 Energy Storage RFP – Invitation to Comment – Round 2**

[redacted] is pleased to submit the attached comments for consideration on the Final Draft ISC Contract and the Final Draft Preliminary Proposal Requirements released by the Illinois Power Agency (IPA) on June 1, 2026.

[redacted]

[redacted], we commend the IPA in creating an offtake opportunity that ensures revenue certainty for energy storage in Illinois. We are confident that a successful RFP will play a critical role in helping the state meet its ambitious energy and climate goals.

[redacted] greatly appreciates the Agency's consideration of our comments and recommendations. Please contact me by email at [redacted] for any clarifications or further information. Thank you.

Respectfully submitted,

[redacted]

[redacted]

[redacted] [redacted]

Topic 1: Hourly Availability Report

Question 1: What PJM, MISO, or alternative systems would allow the Buyer or the IPA to independently verify the availability of the energy storage system?

PJM collects granular, hourly resource-level performance data through their existing settlement and market systems.

PJM eDART (the Electronic Dispatcher and Reliability Tool) captures real-time and historical outage, derate, and availability data for generation resources, including storage. PJM also maintains hourly metered output and state-of-charge data through its settlements systems (e.g. Hourly Generation Data / Market Settlements data), which is verifiable by PJM members and can be made accessible to the Buyer with appropriate authorization from the Seller.

[redacted] encourages the IPA and Buyer to rely on these systems as the primary verification mechanism rather than creating a parallel reporting regime.

[redacted]

[redacted] [redacted]

Topic 2: Performance Assurance

Question: Is the proposed schedule for the reduction of the amount of Performance Assurance Collateral held over the 20-year term reasonable? Why or why not? If not, what further refinements or changes should be considered for this requirement?

[redacted] appreciates that the final draft ISC Contract introduces a step-down schedule for Performance Assurance Collateral. As raised in [redacted], a flat $50,000/MW requirement held for the full 20-year term is significantly more stringent than comparable programs and would impose unnecessary costs that flow through to Illinois ratepayers. The introduction of a declining schedule (Table A) is a constructive step in the right direction, however, [redacted] still sees the following issues with the Performance Assurance requirements:

The starting collateral level remains too high relative to comparable programs.

While the step-down structure is an improvement, the starting reference point of $50,000/MW (100% of Initial Contract Capacity for the first 60 months) remains materially higher than the comparable programs:

- NYSERDA's Index Storage Credit program requires Contract Security starting at $20,000/MW, stepping up to a maximum of $40,000/MW depending on construction timeline, and refunded at project Commercial Operations Date (COD).
- Maryland's NGEA Energy Storage program requires a $25,000/MW surety bond, which is half of the proposed Illinois starting level, structured as a COD-delay mechanism and therefore refunded at project COD.

The benefit of utilizing an ISC structure is that it ties revenue directly to actual delivered performance via the indexed payment mechanism. The additional protection provided by a high collateral requirement is limited, while the carrying cost due to higher strike prices is ultimately carried by Illinois ratepayers.

As in [redacted], for an example 200MW project, the cost differential between $50,000/MW and $25,000/MW collateral, assumed to be carried via letter of credit at approximately 2% per annum, equates to roughly $100,000 per year, or $1 million in present value terms over the contract term (8% discount rate).

The step-down should begin earlier and be calibrated to a typical project's risk profile from construction to operations, as opposed to remaining contract tenor.

Table A structures the step-down based on "Months Remaining in the Acceptable Vintage Period," which measures time remaining in the contract term rather than the project's operational status. A project would remain at the 80-100% collateral tier for up to 10 years after achieving Commercial Operation, even though the risk profile changes fundamentally at COD.

- Pre-COD – collateral appropriately secures against development, permitting, interconnection, and construction risk. These are risks that the Seller controls and justify a higher security level.
- Post-COD – the relevant risks are ongoing operational performance and counterparty creditworthiness. These risks are already covered by the ISC contract (underperformance reduces Seller's revenue) and by the independent requirements imposed by project debt, tax equity, and insurance providers, all of which require their own performance and creditworthiness standards.

[redacted] recommends that collateral requirement should either be eliminated at COD or see a significantly greater step-down at COD, to accurately reflect project risk profiles and take advantage of the risk protections already built into the ISC contract.

A milestone-based tranche structure during the pre-COD period would better align collateral with actual residual risk

[redacted]

[redacted] [redacted]

Even within the pre-COD period, the current structure requires the full Table A amount to be posted shortly after contract award (within 8 business days of the Commission decision), before key development milestones such as execution of an interconnection agreement, receipt of Notice to Proceed, or financial close. As proposed [redacted], the IPA should consider a tranche approach, consistent with the NYSERDA model, under which:

- An initial, reduced tranche of collateral (e.g. 50% of the otherwise-applicable Table A amount) is posted at contract execution; and
- The remaining tranche is posted upon achievement of a defined milestone, such as Notice to Proceed or financial close, at which point development risks are substantially mitigated and the project's viability is far more certain.

This phased approach would reduce the capital that Sellers must commit (and price into their bids) during the period of highest development uncertainty, without reducing the security available to Buyer once a project has reached a more advanced stage of development.

Recommended changes:

[redacted] recommends that the IPA consider the following refinements to the Performance Assurance Collateral framework, which can be adopted together or independently:

1. **Reduce the starting reference** from $50,000/MW to a level closer to $25,000–$30,000/MW, bringing Illinois into closer alignment with Maryland's NGEA program and the beginning of NYSERDA's tranche structure.
2. **Either eliminate collateral requirements at COD or introduce a significant step-down** of at least 50% from the pre-COD collateral level, recognizing that the risk profile of an operating asset is fundamentally different from that of a project under construction.
3. **Allow a milestone-based tranche structure during the pre-COD period**, so that the full Table A amount is not required to be posted in its entirety within 8 business days of the Commission decision, but is instead phased in as key development risks (interconnection, permitting, financial close) are resolved.

Together, these refinements would preserve robust security for the Buyer and IPA at each stage of a project's life while reducing the unnecessary carrying costs that the current structure imposes, which will be passed directly through to Illinois ratepayers via higher strike prices.

[redacted]

[redacted] [redacted]

Topic 3: Commercial Readiness

Question: Is the minimum size requirement of 20 MW for each energy facility submitted for the commercial readiness requirement appropriate and reasonable? Why or why not? If not, what project size is appropriate? What further refinements or changes should be considered for the commercial readiness requirement?

[redacted] supports the 20 MW minimum size requirement adopted in the final draft Preliminary Proposal Requirements.

[redacted], aligning the commercial readiness threshold with the 20 MW minimum project size for participating energy storage resources in this procurement ensures that the experience Bidders rely on to demonstrate commercial readiness is representative of the scale and complexity involved in delivering a utility-scale BESS project. A lower threshold would risk qualifying Bidders based on experience with small distributed-scale projects that do not present comparable development, financing, interconnection, or construction challenges. We therefore consider 20 MW to be the appropriate level.

However, [redacted] recommends that the commercial readiness requirement be further refined to require that the qualifying experience be specific to battery energy storage systems (BESS), either Standalone or Co-located, rather than all technologies. As proposed [redacted] BESS presents distinct development, interconnection, construction, and operational challenges (e.g. fire safety and code compliance, performance, degradation) that are not comparable to other facility types such as utility-scale solar or thermal generation. A Bidder demonstrating 100 MW of aggregate notice-to-proceed experience drawn entirely from non-storage energy facilities would not have demonstrated the relevant commercial readiness contemplated by Section 1-75(d-20)(6) of the IPA Act for delivering a utility-scale energy storage project.

We therefore recommend that the final Preliminary Proposal Requirements specify that the 100 MW of combined nameplate capacity (with each qualifying facility at least 20 MW) must be drawn from BESS, either Standalone or Co-located, and should not be satisfied using experience from non-storage generation facilities.

[redacted]