

**REACT Responses to the Illinois Power Agency’s
2026 Illinois Resource Adequacy Study Mitigation Plan
Post-Workshop Stakeholder Questions**

The Coalition to Request Equitable Allocation of Costs Together (“REACT”) submits the following comments in response to the Illinois Power Agency’s questions regarding the development of the Mitigation Plan under Section 9.15(o) of the Illinois Power Agency Act.

These comments:

1. Reflect the Comments REACT submitted to the Illinois Commerce Commission (“ICC”) in response to its first request for comments regarding the Integrated Resource Plan (“IRP”);
2. Incorporate additional reliability-focused analysis appropriate for a near-term mitigation framework;
3. Recommend that the Mitigation Plan modeling should be structured around adequacy, reliability, safety, and affordability as threshold criteria, before policy objectives are optimized; and
4. Emphasize that the Mitigation Plan should explicitly evaluate customer-directed and self-direct resource deployment mechanisms as reliability-enhancing tools.

The Mitigation Plan differs from the long-term IRP in that it is specifically designed to address near- and mid-term reliability risks under tightening reserve margins and accelerating load growth. Therefore, certain modeling assumptions and sensitivities warrant more immediate and granular examination in this proceeding than in the IRP.

Battery storage, renewable generation, and energy efficiency investments deployed voluntarily by customers can be deployed effectively to reduce system peak demand, enhance localized reliability, and mitigate upward pressure on rate-based program costs. The Mitigation Plan should treat customer empowerment not as a secondary policy feature, but as a complementary reliability resource that, if appropriately structured, can reduce system risk exposure and diversify resource ownership during periods of constrained reserve margins.

Technical Questions (Mitigation Plan Inputs & Analysis)

Question 1: Are there any specific analysis, modeling, scenarios, or sensitivities that were not completed or incorporated as part of the RA Study process (recently completed), and that stakeholders did not include in the response to the ICC Request for Comments (due February 9) that should be considered by the Agencies as part of the Mitigation Plan modeling and analysis?

- If yes, please details on such recommendations, including their intended focus or methodology, and usefulness.
- Please provide any citations or references to support your recommendations, including data sets or inputs (or references to where those data sets or inputs can be found) that are necessary to complete the analysis.

- If modeling, scenarios or sensitivities were not recommended as part of the ICC Request for Comments process, please explain why they should be included in the Mitigation Plan analysis and not the IRP process?

REACT Response

Yes. The following analyses should be incorporated into the Mitigation Plan modeling process:

1. Reserve-margin-triggered Load Curtailment Mechanisms. As stated in REACT’s IRP comments, demand growth is not independent of supply. The Mitigation Plan modeling should:

- Include a reserve-margin-triggered load interconnection constraint, where large load additions are slowed or curtailed if modeled reserve margins for a specified region fall below established reliability thresholds.
- Reflect real-world interconnection practice: large loads cannot achieve grid connection absent sufficient capacity.

This dynamic modeling feature is particularly appropriate in the Mitigation Plan because it directly addresses short-term reliability mitigation.

2. Early Retirement Sensitivity for Gas Fueled Generation Assets. Modeling should not assume existing natural gas fueled generation assets remain fully operational throughout CEJA’s zero emissions timelines. The Mitigation Plan should include a premature economic retirement sensitivity for gas facilities, recognizing:

- Merchant generators may retire based on market and project economics.
- Compliance uncertainty may accelerate exit decisions.
- Reliability risks increase if modeling assumes continued operation that ultimately does not materialize.

This sensitivity is critical to near-term mitigation planning.

3. Hourly Reliability and Duration Metrics. The Mitigation Plan should incorporate:

- Hourly supply/load balancing;
- Explicit outage duration outputs; and
- Realistic import capability assumptions (recognizing PJM and MISO capacity shortages already identified in the RA Study)

Unlike the IRP, which may examine long-run resource mixes, the Mitigation Plan must evaluate event duration risk (multi-hour and multi-day shortfalls) and not solely LOLE averages.

4. Probabilistic Weather Stress Scenarios. The Mitigation Plan should include:

- Extreme winter and extreme summer stress cases;

- Correlated outage modeling; and
- Limited regional import capability during stress events.

5. Self-Direct Participation Sensitivity. The Mitigation Plan should include a modeled self-direct participation sensitivity to evaluate the impact of accelerated customer-sited deployments of storage, renewable generation, and energy efficiency measures on system peak demand and reserve margins. This sensitivity should examine varying participation levels among eligible customers and reflect realistic deployment timelines for behind-the-meter resources.

Customer-directed deployments can serve as near-term peak-reducing capacity resources without requiring full rate-base investment or long construction lead times. Modeling such participation will allow the Agencies to quantify the degree to which voluntary, customer-financed resources can mitigate identified reliability gaps.

These scenarios are particularly appropriate in the Mitigation Plan because mitigation resources must address short-duration, high-impact events.

Question 2: Is there any new or updated data or information that has been issued or otherwise has been made available that was either not utilized in the RA Study, became available after RA Study modeling and analysis was already completed, and/or was not recommended for inclusion in the ICC Request for Comments that should be considered in the development of the Mitigation Plan?

- If yes, please provide references. (The Agencies prefer direct links and/or submission of the referenced material.)
- If not recommended as part of the ICC Request for Comments process, please explain why they should be included in the Mitigation Plan analysis and not the IRP process?

REACT Response

The Mitigation Plan should incorporate:

1. Updated PJM load forecast revisions reflecting data center projections;
2. Updated interconnection queue attrition rates;
3. Recent forced outage rate data reflecting stress-event performance;
4. Updated RTO accreditation adjustments (ELCC values).

Potential impacts of the U.S. Department of Energy's October 23, 2025 Advanced Notice of Proposed Rulemaking (ANOPR) for the interconnection of Large Loads (typically larger than 20

MW) to interstate transmission systems. These updates should be included in the Mitigation Plan because:

- The Mitigation Plan addresses near-term operational risk,
- Recent load growth forecasts materially alter adequacy outlooks, and
- Interconnection realism is essential for mitigation feasibility.

Question 3: The primary focus of the Mitigation Plan analysis will be on what solution sets of resources and/or policy options can be accessed over various terms (periods of time) to mitigate electric reliability risks and meet resource adequacy needs. A function of the analysis includes expectations and timing surrounding CEJA-driven fossil generation facility retirements throughout Illinois (specifically coal). The initial deadline for such retirements by coal facilities is 2030. The Agencies are seeking further insight from coal generation owners/operators or any other stakeholders with pertinent and detailed information – requesting clarity around when the final determination surrounding closure is required. This includes when a determination to remain operational for a period of time into and beyond 2030 is required. Specifically:

- What is the ‘drop-dead’ date (at least by year) that facilities must be notified that facility retirement is delayed ensuring the facility can remain operational? (e.g., facility owners must receive notification to continue operation by Q1 2029 to remain operational into or beyond 2030)
- What are the specific considerations that impact any such date? Please provide details and the timing-based impacts of those considerations. (this may include investments in expanded emissions technology, substantive investments in facility assets to ensure facility remains operational, fuel)
- Please explain if any such timing considerations include RTO or federal reliability must run (RMR) provisions which could mandate a facility remain operational for a specified period of time.

REACT Response

It is unclear why the focus of this question is on coal facilities rather than all CEJA-driven fossil generation facility retirements, including natural gas. The Mitigation Plan should explicitly analyze the following for all CEJA-driven facility retirements:

1. Notification Timing. All fossil generation facilities likely require notification of continued operation:

- At least 18–24 months prior to a statutory retirement date,
- Potentially earlier if capital expenditures are required.

The “drop-dead” date depends on:

- Major maintenance cycles;
- Fuel contracting timelines;

- Environmental compliance investments;
- Workforce retention considerations.

2. Investment Lead Times. Mitigation modeling should reflect:

- Capital upgrade timelines;
- Emissions control installation timing;
- Major outage scheduling cycles;
- Capacity auction requirement;
- Fuel procurement commitments.

If notice is provided too late, units may not remain viable even if policy relief is granted.

3. RTO / RMR Considerations. The Mitigation Plan should explicitly address the procedural and economic feasibility of invoking RMR mechanisms as part of mitigation strategy. Modeling should consider:

- RTO Reliability Must Run (RMR) designations;
- Timing for RMR determinations;
- Customer costs that would result from RMR designations;
- The need to retain “black start” facilities;
- Whether RMR compensation structures align with CEJA-driven timelines.

Question 4: A substantive driver identified and modeled through the RA Study is load growth, heavily influenced by data center interconnection forecasts. Since issuance of the RA Study, the Agencies are aware of a recent update to PJMs load forecast, inclusive of data center interconnection projections. During the January 27th RA Study Workshop, questions and comments were received surrounding data center load forecasts, requesting further consideration of how data center interconnections are impacting load forecasts used in the RA Study and/or to be used in the Mitigation Plan.

- In addition to the forecasts considered in the RA Study (utility forecasts and RTO forecasts) and the recent PJM load forecast update, are there any additional load growth forecasts and/or sensitivities that should be considered?
- If yes, please provide reference(s) to the forecasts and a detailed breakdown of the sensitivities that should be considered (including over relevant time horizons).

REACT Response

Beyond utility and RTO forecasts, Mitigation Plan modeling should examine:

1. High data center clustering sensitivity (localized transmission constraints);

2. Staged data center interconnection scenarios (front-loaded vs. delayed);
3. Industrial reshoring scenarios;
4. Sensitivity where reserve margins limit new large-load interconnections; and,
5. The sensitivity of import capabilities of both PJM and ISO to load growth in neighboring states and regions.

Importantly, data center growth should be modeled as a discrete, step-change sensitivity, and not averaged into general load growth.

In addition, modeling should examine whether customer-sited distributed resources and self-direct deployments in proximity to large load clusters can offset localized transmission constraints and reduce incremental capacity procurement requirements. This analysis would allow the Agencies to determine whether targeted customer empowerment mechanisms could serve as partial mitigation tools in areas experiencing concentrated load growth.

Question 5: Are there any additional factors that should be considered or explored in greater details in addition to those provided in response to questions 1-4, above, to support the development of the Mitigation Plan?

REACT Response

The Mitigation Plan should:

- Evaluate import limitation scenarios reflecting simultaneous PJM/MISO stress;
- Distinguish dispatchable vs. non-dispatchable effective capacity;
- Model duration risk (not just capacity margins);
- Explicitly quantify outage hours and economic disruption exposure; and,
- The risks of supply shortfall resulting from the potential for inverter-based resources to unexpectedly trip during grid disturbances as identified by NERC in its [*Aggregated Report on NERC Level 2 Recommendation to Industry: Findings from Inverter-Based Resource Model Quality Deficiencies Alert*](#).

Mitigation resources must address firm reliability gaps for the duration of potential stress, not merely policy compliance metrics.

The Agencies should also evaluate the role of voluntary customer-directed resource deployments as part of the mitigation solution set. Self-direct mechanisms allow customers to internalize reliability investments, reduce their contribution to system peak, and lessen reliance on centrally procured resources. Portfolios that incorporate customer empowerment tools may reduce aggregate system costs, diversify reliability contributions, and provide flexibility during implementation of larger-scale infrastructure investments.

Mitigation Plan & IRP Process Alignment

Question 6: Both the Mitigation Plan required under Section 9.15(o) and the Integrated Resource Plan required under CRGA begin with an assessment of Illinois energy resource needs and require a proposal for meeting those needs leveraging a broad solution set (emission reduction requirement relaxation; new generation resources; energy storage; transmission development; demand-side options) optimized across a fairly consistent set of metrics (including cost, emission impacts, environmental justice community impacts, and ensuring “adequate, reliable, efficient, and environmentally sustainable electric service”).

- What suggestions do you have for how the IPA, IEPA, and ICC can most effectively merge these processes to keep parties from duplicative work and to ensure clarity and certainty of administrative/regulatory outcomes?
- Are there any unique considerations which you believe the IPA, IEPA, and ICC must navigate in working to merge these workstreams?
- Would you be supportive of coordinating administrative filings and consolidating plan approval proceedings?

REACT Response

Mitigation decisions addressing near-term reliability should not be delayed pending full IRP completion, but the Mitigation Plan and IRP processes should be coordinated to:

- Avoid duplicative modeling efforts;
- Ensure consistent base assumptions; and
- Reduce administrative inefficiency.

REACT recommends the Agencies take the following steps to coordinate:

1. Establish a Common Dataset
 - Shared load forecasts,
 - Shared outage assumptions, and
 - Shared accreditation values.
2. Treat the Mitigation Plan as a Near-Term Reliability Layer
 - Focused on short- and mid-term adequacy risk,
 - Uses IRP base modeling inputs,
 - Analyzes interim procedural mechanisms,

- Evaluates conditional resource approvals,
 - Evaluates harmonized self-direct and customer participation structures, and
 - Applies stress-case overlays.
3. Treat the IRP as a Long-Term Resource Optimization Layer
 - Broader policy integration, and
 - Lifecycle cost optimization.
 4. Synchronize administrative processes
 - Coordinated filings;
 - Consolidated evidentiary records where feasible;
 - Consistent eligibility thresholds and program structures for self-direct programs across mitigation and IRP proceedings;
 - Alignment of modeling assumptions across Agencies.
 5. Establish regular and relevant communications with stakeholders.

REACT's central position is that:

1. Resource adequacy and reliability are threshold criteria.
2. Customer empowerment and voluntary self-direct resource deployment should be evaluated as reliability-supporting tools that can reduce peak exposure, mitigate cost impacts, and enhance system resilience without displacing threshold adequacy requirements.
3. Modeling should reflect realistic operational constraints.
4. Demand growth must be supply-aware.
5. Duration and event severity must be explicitly quantified.
6. Affordability must be evaluated on a total-system-cost basis.

The Mitigation Plan should not assume that reliability can only be secured through centralized procurement; properly structured customer-directed participation can serve as a complementary, flexible, and cost-mitigating component of Illinois' near-term reliability strategy. The Mitigation Plan presents an opportunity to incorporate these structural improvements to ensure Illinois maintains safe, reliable, and affordable electric service during a period of tightening reserve margins and accelerating load growth.