Responses of LS Power to
Illinois Power Agency (IPA), Illinois Commerce Commission (ICC),
Illinois Environmental Protection Agency (IEPA)
Resource Adequacy Study Post-Workshop Stakeholder Questions
July 16, 2025

LS Power appreciates the opportunity to provide these comments to the IPA, ICC and IEPA to assist in the development of the Resource Adequacy ("RA") Study. This document provides LS Power's responses to the twelve (12) stakeholder questions issued by the IPA on June 18, 2025, for the RA Study, pursuant to Section 9.15(o) of the IEPA Act. These responses reflect our experience operating both gas-fired and wind generation facilities in Illinois, (see generally ICC Docket No. 22-0749). These responses draw on LS Power's experience of operating both 3.8 GW of gas-fired generation and 412 MW of wind generation in Illinois[1] as well as our active participation in the ICC's Renewable Energy Access Plan ("REAP") process (*see generally* ICC Docket No. 22-0749)[2] which included submitting comments supported by detailed analysis from PA Consulting, reviewing input from other stakeholders, and considering reliability assessments conducted by PJM and other relevant entities. The recommendations aim to ensure grid reliability, affordability and compliance with the Climate and Equitable Jobs Act or "CEJA," Public Act 102-0662. LS Power reserves the right to take additional or different positions once it has had the opportunity to review the responses and comments provided by other parties.

Who is LS Power?

Founded in 1990, LS Power is a development, investment, and operating company focused on the power and energy infrastructure sector. Our objective is to develop and deliver the most reliable, affordable, and increasingly clean energy sources that can effectively be scaled today. Since its inception, LS Power has developed, constructed, managed, and acquired more than 46,000 MWs of competitive power generation and 680 miles of transmission infrastructure, for which it has raised over $50 billion in debt and equity financing to invest in North American infrastructure. For decades, LS Power has been leading the energy industry's evolution, often introducing or commercializing new technologies and developing new markets.

LS Power is focused on solving complex energy problems to improve the world. With our national fleet of utility scale solar, wind, hydro, natural gas-fired and energy storage generation projects, our customer-facing distributed energy resources and energy efficiency platforms, and by building the transmission that connects it all, we are investing in energy infrastructure that makes the grid cleaner and more reliable.

LS Power already has a substantial presence in Illinois, owning and operating approximately 3.8 GW of Illinois-based gas-fired generation, and 412 MW of wind generation. LS Power's Illinois portfolio consists of quick start peaking capacity located near the Chicago load center that provides services essential to the reliability of the Illinois power grid that cannot be provided by baseload or renewable facilities. In addition to actively participating in

[1] https://www.lspower.com/what-we-do/

[2] Unless otherwise noted, the documents referenced herein were filed with the ICC in docket 22-0749 and can be found using this link: Documents for 22-0749.

this workshop process, LS Power has been active in the ICC's REAP proceeding and subsequent ICC workshops, including those related to battery storage, and continues to intend to build, own and operate energy facilities in Illinois.

Responses to Stakeholder Questions

Topic 1: Resource Adequacy Study Goals and Scenario Analysis Considerations

Question 1: The Agencies recognize this study process is purposefully targeted in its nature, with Section 9.15(o) providing clear goals and expectations of the resource adequacy study and resulting report. What additional goals, objectives, or evaluation metrics should be considered, either as part of this study process or future resource adequacy study efforts?

Response: The RA Study should prioritize grid reliability by assessing the role of natural gas peaker plants in preventing blackouts, estimated at 25 hours annually by 2030 in ComEd's area, costing $3.1 billion (LS Power Initial Comments, Appendix A). The Agencies also should include the following additional metrics:

- Blackout risk probability (hours/year).
- Economic costs of reliability shortfalls ($3.1 billion by 2030, $55 billion by 2045).
- Emissions impacts of premature retirements (e.g., 13,500 tons SO_2, 8 million tons CO_2, 2022–2029).
- Rate impacts on all ratepayers, especially environmental justice communities.
- Availability of Black Start units. PJM is evaluating the need for Fuel Assured Black Start Units across transmission zones and may invoke the Reliability Backstop—its last-resort procurement tool—to meet minimum requirements. An RFP may be necessary. These units must start independently and sustain 16 hours of full-load operation, with reliable on-site or pipeline fuel supply, or proven hybrid capability. Natural gas units currently provide much of this capacity, and the implications of reducing such resources must be carefully considered.[3]

These recommendations align with CEJA's reliability and equity goals, supported by the large energy users' call for urgent action. (*See* ELCON/REACT Response Comments at 7).

Question 2: Which variables are the highest priority to explore? Further, are there important policies or drivers missing in addition to those outlined in the preceding stakeholder workshop that could help shape scenario development?

Response: The most urgent variable is CEJA's peaker plant retirement schedule, which could lead to up to 25 hours of blackouts by 2030—exposing ratepayers to at least $3.1 billion in costs—and as much as 400 hours of blackouts by 2045 in ComEd's territory alone, with projected costs exceeding $55 billion (LS Power's Initial Comments, Appendix A). These estimates do not account for the broader secondary impacts Illinois would face, including lost economic development, harm to individuals and businesses, and long-term damage to the state's reliability and competitiveness if blackout risks are not promptly and decisively addressed.

[3] See Attached recent PJM Black Start PowerPoints.

Missing drivers in the present RA analysis include:

- A review of CEJA's generator retirement timeline to balance reliability, costs and emissions.
- Incentives for energy efficiency and demand response, which can reduce peak load cost-effectively (LS Power's Response Comments at 13).
- Scenarios should test delayed retirements (5–10 years) and competitive market solutions, as urged by ELCON/REACT (ELCON/REACT Response Comments at 7).
- Scenarios forecasting both i) the baseline of the stated goals of CEJA being reached on proposed timelines, and ii) at least two scenarios that project a slower transition and realization for CEJA on longer timelines; including discussion of the costs and attendant feasibility of each programmatic effort.
    - Sub-issues relating to the growth in EV market penetration, and plan dependency on attainment of BESS goals.
- Consistent review of the status of the PJM interconnection queue for generation expected to come online by 2030, 2035, etc.

The study should also consider:

- State-level economic impacts of blackouts, including– public health and welfare impacts, reduction of economic development opportunities, and granular job loss percentage expectations and the cost of programmatic efforts to address these foreseeable outcomes.
- Regional economic impacts of generator shutdowns forced by CEJA, including in particular the impact on schools and communities of elimination of property taxes in-state manufacturing, and jobs in areas with generation shutdown.
- The role that BESS can play in addressing reliability risks in Illinois; the scale and timeline for BESS deployments required to meet various forecasted plans; and the degree of financial and policy support these resources will need in order to be brought online within the timeframe required.

Question 3: Which of the following drivers are most critical to explore in the resource adequacy modeling scenarios and why? a. Extreme weather, b. Demand growth, c. Thermal retirements, d. Transmission build and future needs, e. Generation resource diversity, f. Out-of-state reliance on generation resources, g. Some other driver not described above.

Response: Resource adequacy demands a holistic approach because all of the identified "drivers" — extreme weather, demand growth, thermal retirements, transmission build, generation resource diversity, out-of-state reliance, and additional drivers like new construction/interconnection — are deeply interconnected. These drivers cannot be logically ranked in isolation, as each influences reliability, affordability, and compliance with CEJA. No single driver can independently achieve any of these objectives, and efforts to prioritize one over the others risk oversimplifying the analysis and obscuring their interdependent effects. As outlined below, and supported by both data and stakeholder input, each driver plays a critical role in the broader system. Importantly, the Agencies should recognize that the thermal retirement schedule is the only driver the State has direct control over.

a. **Extreme Weather**: Extreme weather events, such as heatwaves or winter storms, stress the grid by increasing demand and disrupting supply. However, reliability risks also arise during shoulder seasons (e.g., spring/fall) when plants are offline for maintenance, creating similar vulnerabilities (LS Power Initial Comments, Appendix A).

b. **Demand Growth**: Forecasting demand growth is challenging but critical, particularly due to rapid data center expansion (e.g., >300% growth in some PJM zones; PJM 2023 Load Forecast Report, pjm.com). CEJA's goal of 1 million electric vehicles by 2030 would result in a 4% annual load increase. (*Id.*) However, achieving that goal depends highly upon supportive state and federal policies. Unpredictable demand spikes could strain resources if not paired with adequate generation and transmission planning.

c. **Thermal Retirements**: CEJA's peaker plant retirement schedule, a self-imposed constraint upon the system, risks 25 hours of blackouts by 2030 and 400 hours by 2045 in ComEd's service area, costing $3.1 billion and $55 billion, respectively, with increased emissions (13,500 tons SO_2, 8 million tons CO_2, 2022–2029) from out-of-state reliance (*Id.*) Accordingly, delaying retirements is critical to balance reliability and CEJA's environmental goals (LS Power's Proposed Language at 2).

d. **Transmission Build and Future Needs**: Replacing 8.4 GW of peaker capacity with a battery energy storage system (BESS) and intermittent load would strain transmission capacity and ratepayer affordability. (*Id.* at 3). Renewable integration (38% penetration by 2030 according to CEJA) doubles transmission overloads, necessitating robust planning (MISO Long-Range Transmission Plan, misoenergy.org).

e. **Generation Resource Diversity**: The operation of peaker plants in Illinois, with 6-minute startups and multiple daily starts, are essential for balancing intermittent renewables (22-0749, LS Power Response Comments at 10). Diversity ensures reliability as renewable penetration grows, aligning with FERC and NERC warnings about dispatchable resource retirements (*Id.* at 11–12).

f. **Out-of-State Reliance**: Increased reliance on out-of-state fossil generation raises emissions, undermining CEJA's environmental justice goals (LS Power Response Comments at 7). This driver is directly tied to thermal retirements and transmission constraints, as Illinois' PJM (70%) and MISO (30%) markets depend on regional coordination.

Other critical issues:

g. **New Construction and Interconnection**: Delays in new generation projects (e.g., only ~50 GW of MISO's 235.23 GW queue had agreements by August 2023; misoenergy.org) and interconnection bottlenecks (e.g., PJM's queue backlog; pjm.com) limit renewable deployment. ABB Velocity Suite data is critical for realistic modeling (*Id.* at 15).

h. **Consistent, Durable Capacity Market Policy**: Stable capacity market policies provide the revenue certainty developers need to secure financing and commit to new generation or retention of existing assets. Without predictable market signals, long-term planning becomes fragmented, increasing the risk of underinvestment and jeopardizing grid reliability.

While the interconnection of these drivers is obvious, self-imposed thermal retirements heighten reliance on out-of-state generation, increasing costs to Illinois ratepayers, increase emissions, and elevate reliability risks — particularly if transmission buildout and new resource development fail to keep pace. Resource diversity can help mitigate these challenges, but only if supported by stable and consistent policy.

Question 4: Are there known or expected developments in federal or state policy that should be integrated into scenario development? Please explain in detail and provide references where possible.

Response: CEJA's peaker retirement schedule (415 ILCS 5/9.15) is the primary policy driving outcomes in Illinois, it is critical that scenarios test delays in CEJA retirements to avoid blackouts (25 hours/year by 2030; LS Power Initial Comments, Appendix A, 22-0749). The One Big Beautiful Bill Act, H.R.1 (2025) may severely impact generation deployment that relies on subsidies, and queue entry (PJM/MISO data). NERC reliability standards and FERC's concerns about dispatchable generation retirements should also be modeled. (LS Power Response Comments at 11–12, 22-0749).

Question 5: How should cost implications or other findings beyond potential reliability shortfalls be presented or considered to support constructive policy decisions?

Response: It is critical that Illinois adopt comprehensive, holistic cost-benefit analysis metrics to assess any plans presented, as whenever the program costs exceed the benefits the public is willing to bear the resulting policy instability undermines the ultimate objective of programmatic planning efforts. Each wave of instability in the energy transition, triggered by idealized objectives, those not deeply counseled by realistic cost appetites, economic performance expectations and technically feasible build-timelines, undermines the ultimate goals of timely energy transition. It is time that we think beyond the politically expedient goals, and counsel to reason our next steps with realistic, technically and economically sound cost-benefit analysis.

At the outset, a sound cost-benefit analysis lays bare the underlying trade-offs required in realizing the various forecasted plans, it considers the benefits against the costs at various sensitivities and then this informs an analysis of the probability of the sustained investments needed to realize those goals, given the nature of the costs. Such plan would present findings in a transparent manner, acknowledging the trade-offs, and then recommend those actions that would have the highest likelihood of sustained success.

The analysis should consistently and systematically evaluate each forecast, considering:

Cost Categories:

1) Direct Costs – Capital investments in generation capacity, transmission infrastructure, and distribution systems;
2) Indirect Costs – Systems operation and maintenance, administrative overhead, grid management structure;

3) Opportunity Costs – Alternative investments foregone, particularly relevant when considering alternative generation mixes;
4) External Costs – Environmental impacts, emissions costs, and social impacts of generation (i.e. job loss/gain, economic development/lack thereof, land use changes, policy change costs, the effect of costs on policy stability and goal attainment, etc.); and
5) Risk Mitigation Costs: Investments in reliability measures, backup systems, and resilience infrastructure.

Benefit Categories:

1) Tangible Benefits – Cost savings, increased efficiency, avoidance of black swan events;
2) Intangible Benefits – Enhanced system reliability, improved ratepayer satisfaction, reduced outage frequency and duration;
3) Environmental Benefits – Emissions and pollution reduction; and
4) Social Benefits – Energy security, economic development, public health benefits.

Resource Adequacy Metrics:

These metrics should be considered granularly on a probabilistic basis at not less than a load-zone level and each set to a cost scalar: Loss of Load Expectations, Loss of Load Hours, Loss of Load Probability, Loss of Load Probability, and Expected Unserved Energy, Effective Load Carrying Capability, Equivalent Firm Capacity, Equivalent Conventional Power, Flexibility Requirements, etc.

The analysis should result in a cost-benefit ratio for each forecasted plan, adjusting future costs and benefits to present values. Then the report should consider the levers Illinois has to ensure the planned outcomes are attained, and considering these limitations, set a probability to the feasibility of each outcome being timely realized, make a recommendation inclusive of those high-impact levers requiring use to attain the recommended plan.

As an outgrowth of other proceedings in Illinois, LS Power calls closer attention to these factors in the comprehensive analysis:

- Any policy position requiring action by one or more utilities in the State of Illinois.
- Both direct and indirect cost of blackouts ($3.1 billion by 2030, $55 billion by 2045).
- Transmission costs, including those required for BESS-only deployment levels by plan ($11 billion).
- Rate increases (e.g. $1 billion statewide, 2022–2029).
- The economic competitiveness of the State of Illinois.
    - Long-term impacts of data center placement on economic development;
    - The probability and cost to the State of Illinois of industrial facilities relocating to other states as power price tolerances are meaningfully less inelastic compared to other customer classes;
    - The probability, cost and reliability impacts of peaker plants relocating out of state as against the back-drop that these facilities will still need to be located within the regional markets.

Question 6: What blind spots or gaps in the RA Study process do you worry might be overlooked or otherwise not addressed? a. Are the identified blind spots or gaps unique

to customer segments, modeling scenarios, market conditions or other targeted parameter? b. How could the identified blind spots or gaps be addressed?

Response: A key blind spot is underestimating peaker plants' reliability role, risking 36 supply droughts annually by 2045 (2.4 GW shortfall; Appendix A). This disproportionately impacts ComEd customers and environmental justice communities via increased emissions (13,500 tons SO2, 2022–2029). This should be addressed this by:

- Modeling hybrid scenarios (renewables, BESS, peakers).
- Requiring benefit-cost analyses, as urged by LS Power and ELCON/REACT (Response Comments at 7, 13).
- Understanding the proper ratio of flexible generation vs. intermittent renewable generation.

Another critical blind spot is focusing exclusively on CEJA's statutory deadlines to predict peaker plant retirements. In reality, earlier retirements are likely to occur due to significant capital investment needs or potentially uneconomic operation and maintenance costs. The RA Study also should recognize the possibility that developers may relocate the generators out of state in response to other jurisdictions offering incentives and/or providing more welcoming regulations.

Question 7: Have any peer jurisdictions developed scenario(s) through the completion of their own resource adequacy assessments or studies that should also be considered by the Agencies through this Resource Adequacy Study? a. Provide details concerning the scenario(s), which jurisdiction developed the scenario, and provide a link to the supporting detail(s). b. Is the assessment part of a broader resource adequacy assessment, or a more detailed integrated resource planning effort? c. Are there any market conditions or policy considerations that are unique to the jurisdiction and/or the scenarios referenced?

Response: California's Integrated Resource Plan (IRP), developed by the California Public Utilities Commission (CPUC), provides a relevant comparison model for Illinois' RA Study by analyzing scenarios that balance thermal generation retirements with renewable and energy storage integration (CPUC, "Integrated Resource Plan," https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning.
The IRP models scenarios achieving over 50% renewable penetration by 2030, including analyzing battery energy storage system (BESS) limitations (e.g. 4-hour discharge) and the need for flexible, dispatchable generation such as natural gas peakers to ensure reliability during peak demand or low renewable output. This focus on flexible generation aligns with LS Power's recommendations to retain natural gas peaker plants for reliability (Response Comments at 10). While it is true that California's market (CAISO) differs from PJM and MISO structures, the lessons for Illinois are similar, and both should manage resource adequacy to protect the residents and businesses of each respective state during the transition to renewables.

Similarly, the U.S. Department of Energy's https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29_0.pdf *Report on Evaluating U.S. Grid Reliability and Security* (July 7, 2025), issued under Executive Order 14262, outlines a uniform methodology to identify regions at risk of power outages, to ensure critical power generation resources remain operational, and to guide federal interventions to ensure grid reliability. The report highlights that continued retirements of reliable baseload power sources, like coal and natural gas, combined with insufficient new firm capacity, could lead to a 100-fold increase in blackout risks by 2030, driven by surging electricity demand from AI-driven data centers and reindustrialization. This report emphasizes the unsustainable status quo, projecting that most U.S. regions will face reliability risks within five years if current trends persist, undermining economic growth and national security. The uniform methodology will inform emergency actions under Section 202(c) of the Federal Power Act and will be updated regularly with industry input to address emerging technologies and risks. (https://www.energy.gov/articles/department-energy-releases-report-evaluating-us-grid-reliability-and-security)

Finally, the New York Independent System Operator's (NYISO) 2025 Power Trends report highlights the challenges of maintaining grid reliability under New York's Climate Leadership and Community Protection Act (CLCPA), consistent with concerns in the U.S. Department of Energy's 2025 grid reliability report. It projects a potential 2,000 MW capacity shortfall by 2035 due to retiring fossil fuel plants, insufficient new renewable capacity, and rising demand from electrification and data centers. This report emphasizes the need for flexible, dispatchable resources like natural gas peakers to balance intermittent renewables. It also identifies transmission constraints and the need for upgrades, to address congestion and to integrate renewables. https://www.nyiso.com/documents/20142/2223020/2025-Power-Trends.pdf/51517a1b-36fa-4f3d-d44d-eabe23598514?t=1748873879190

Topic 2: Analytical Approach to Analysis and Data Assumptions

Question 8: Are there recommendations for specific data sources that could be utilized in this study? a. Are there preferences for certain input assumptions that should be made? b. What prior or concurrent studies could be referenced that might add value or ensure alignment with similar or adjacent work (e.g., queue assumptions, RTO projections)?

Response: Recommended additional data sources include:

- PJM's "Energy Transition in PJM" (February 24, 2023, Response Comments at 12).
- MISO's Renewable Integration Impact Assessment (February 2021).
- PA Consulting's analysis (LS Power's Initial Comments, Attachment A, 22-0749).
- Peterson, C.R., K.A. McDermott, and R.C. Hemphill, (2024). Analysis of Potential Pathways to a Clean Energy Future in Illinois, Prepared for the American Gas Association, Washington, DC.
- ABB Velocity Suite for queue data. Assumptions should include conservative peaker retirements (8.4 GW by 2045) and transmission costs ($11 billion for BESS-only; LS Power's Response Comments at 15). (Reference MISO's Long-Range Transmission Plan (misoenergy.org) and LS Power's REAP comments.)
- California's IRP discussed above.
- NYISO 2025 Power Trends report discussed above.
- https://www.energy.gov/articles/us-department-energy-issues-202c-emergency-order-safeguard-electric-grid-reliability-pjm
- NERC applicable documents.

Question 9: Are there specific transmission constraints, expansion, or projects that should be considered and reflected in a model scenario? Further, Are these transmission considerations intended to target and/or solve specific challenges? Please explain, provide supporting documentation justifying inclusion, and provide pertinent reference materials including reports or studies.

Response: We applaud the leadership of the ICC over the past year working with other states to provide meaningful inputs into PJM's RTEP scenario analysis. At this time we do not have additional recommendations on transmission modeling inputs. We encourage Illinois to be diligent in ensuring consistency between inputs in the PJM modeling process and the state's modeling process.

The RA Study should model the following: These considerations can help ensure reliability, affordability, and CEJA compliance by addressing blackout risks and renewable integration challenges.

1. **ComEd Transmission Constraints**: Heavily loaded lines limit imports from PJM/MISO zones, increasing blackout risks (25 hours by 2030, 400 by 2045; 22-0749, LS Power Initial Comments, Attachment A at 15) with peaker retirements (p. 33, Table A-1). Addresses reliability and renewable integration.
2. **Transmission Expansion Needs**: CEJA's 38% renewable penetration by 2030 doubles line overloads without peakers (*Id.* at 36). BESS-only solutions require $11 billion in upgrades (*Id.* at 30).

3. **Specific Projects**:
    - **MISO LRTP Tranche 2**: Enhances reliability and renewable integration in Illinois.
    - **PJM RTEP**: $6.6 billion in upgrades to address ComEd zone reliability. Mitigates congestion and supports CEJA's goals.

References:

- PA Consulting, *Decarbonizing the Illinois Grid* (2022), pp. 15, 30, 33, 36.
- PJM, *Energy Transition Study* (2023), pjm.com.
- MISO LRTP, misoenergy.org.
- NERC, *2022 Long-Term Reliability Assessment*, nerc.com.

Question 10: Are there specific assumptions that should be considered concerning generation resources, including buildout (queue, pace, technology availability) or retirements, both in-state and regionally in the RTO markets?

Response: All of the identified assumptions should be considered.

a. Which proposed assumptions should be considered as part of the base case and which are best considered as part of a prospective scenario? b. Which assumptions are contingent upon specific policy and/or legislative conditions being met or otherwise enacted?

Response: Base case assumptions should include:

- Current peaker capacity.
- CEJA's retirement schedule (zero emissions by 2030 and 2045).
- Prospective scenarios should test:
    - Delayed retirements (5–10 years, saving $7.5 billion).
    - Renewable buildout (15.3 GW nameplate by 2030, per PJM queue. (These depend on CEJA's emissions limits and federal policies (e.g., Inflation Reduction Act), as noted by ComEd (Response Comments at 9) and the One Big Beautiful Bill.)

Question 11: As a component of the RA Study, the Agencies will be seeking to obtain utility and RTO load forecast projections and the underlying assumptions behind the load forecasts. In addition to these utility forecast assumptions, what additional assumptions should also be considered, either embedded in a base case or considered in scenarios? Further, what data sources should be drawn upon, supporting any load forecast modifications? (i.e. large load / electrification growth) a. Provide details on why these additional assumptions should be considered during the modeling process? b. Are any proposed load forecast assumptions directly impacted and/or predicated upon specific to policy, legislative, or other conditions being met and/or otherwise enacted?

Response: Include electrification-driven demand growth (1 million EVs by 2030, per CEJA, increasing load 4% annually; Appendix A). Data sources:

- EIA's electrification trends (eia.gov).

- PJM's 2023 Load Forecast Report (>300% data center growth; pjm.com). These are critical for resource adequacy planning and depend on CEJA's EV incentives and federal policies (e.g., Infrastructure Investment and Jobs Act; One Big Beautiful Bill).

Question 12: Are there any additional considerations - data inputs, policy, drivers, or assumptions - that Stakeholders believe the Agencies should consider, not already explained in response to the preceding questions? Please explain in detail.

Response: Prioritize energy efficiency and demand response to reduce peak load (Response Comments at 15). Scenarios should model these programs, which are estimated to save over $1 billion in consumer costs (2022–2029; Appendix A). The ICC should explore regulatory policies beyond RTO frameworks, aligning with CEJA's cost-effectiveness goals (220 ILCS 5/8-512(a)(9)) and ELCON/REACT's recommendations to embrace customer-centric solutions. (ELCON/REACT Response Comments at 13).

Conclusion

LS Power urges the IPA, ICC and IEPA to incorporate these recommendations as it develops the Resource Adequacy Study to provide guidance on next steps to ensure a reliable and affordable clean energy transition.

ATTACHMENTS

PJM Black Start Reliability Backstop Process

Ray Lee
Lead Engineer, Generation
Operating Committee
May 8, 2025

Fuel Assured Black Start Background

- PJM Black Start (BS) Fuel Assurance (FA) business rules approved by FERC in December 2023
- Requires a minimum of one FA BS unit for each transmission zone
- PJM is working to meet FA BS requirements through the 2023 RTO Wide and 2024 Incremental BS RFP
- The Reliability Backstop process may be needed if FA needs are not fulfilled

Fuel Assured Black Start Unit

A single generator that is able to start without an outside electrical supply and running 16 hours or more at full load and either stores at least 16 hours of fuel on site, can operate independently on 2 or more interstate pipelines, is directly connected to a natural gas gathering system or is an intermittent or hybrid resource that has been evaluated by the Transmission Provider to be capable of providing 16 hours of full load operation with 90% confidence and meets all other requirements for Black Start Units.

Reliability Backstop Background

- 2013 System Restoration Strategy Task Force (SRSTF) revised PJM's restoration strategy to prepare for the coal to gas transition
- Reliability Backstop RFP
  - Last resort tool to fulfill BS needs
  - Transmission Owner is required to submit a proposal
  - Never been used

Key SRSTF Changes

Black Start (BS) and Critical Load (CL) Criteria	Cross-zonal BS Support
Five Year RTO Wide BS RFP	Reliability Backstop RFP

PJM Minimum Black Start Requirements

Minimum of two BS units per transmission zone

Sufficient BS to crank 110% of Critical Load cranking requirement

1. Generator start-up power
2. Nuclear safe shutdown power
3. Power for electric gas compressors

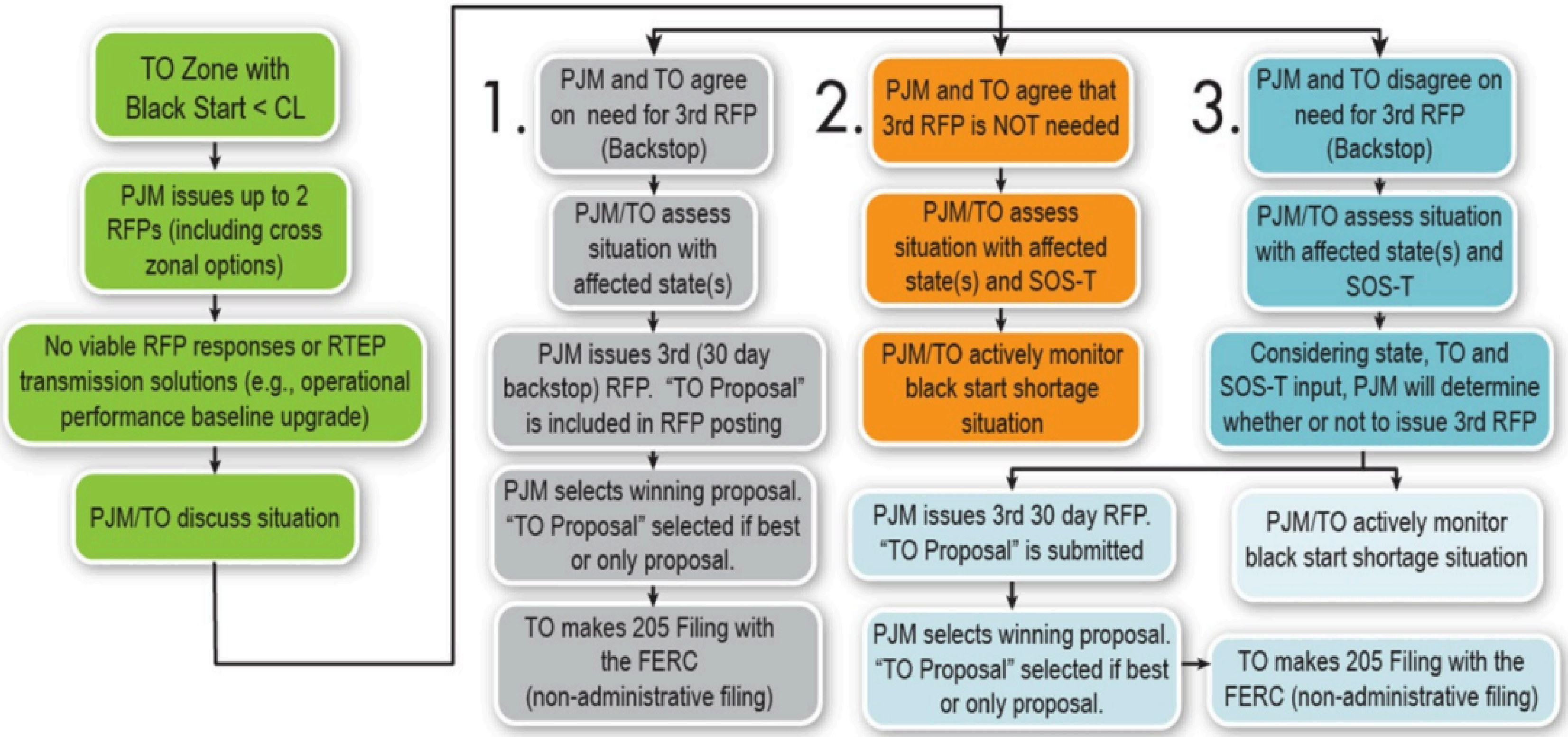
Minimum of one Fuel Assured BS unit per transmission zone

[M36 Attachment A: Minimum Critical Black Start Requirement]

Reliability Backstop Process Overview

PJM Manual 14D: Generator Operational Requirements
Section 10: Black Start Generation Procurement

10.3.5 Reliability Backstop Process Flow Chart



Key Takeaways

- Reliability Backstop RFP may be needed to meet minimum Fuel Assured Black Start requirement
- PJM and Transmission owners will assess the Fuel Assurance deficiency and coordinate with affected states
- Additional education sessions will be scheduled if Reliability Backstop process is needed

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Black Start References

- M12 Section 4.5: Black Start Service
- M14D Section 10: Black Start Generation Procurement
- M36 Attachment A: Minimum Critical Black Start Requirement
- Schedule 6A of PJM OATT – Black Start Service Requirements and revenue calculations

Initiation of Black Start Reliability Backstop Process

Ray Lee
Lead Engineer, Generation
Operating Committee
July 14, 2025

- May OC Reliability Backstop Process Education https://www.pjm.com/-/media/DotCom/committees-groups/committees/oc/2025/20250508/20250508-item-12---reliability-backstop-education.pdf
- Operating Committee Special Session on Black Start Reliability Backstop Process scheduled for Wednesday, July 30, 2025 10:00-12:00 EDT

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