December 15, 2025

2025
Resource Adequacy Study

Submitted to the Illinois General Assembly.

Prepared in accordance with the
Illinois Environmental Protection Act
(415 ILCS 5/9.15(o)).

ILLINOIS ENVIRONMENTAL PROTECTION AGENCY

IPA
ILLINOIS POWER AGENCY

ILLINOIS COMMERCE COMMISSION
ICC

(Intentionally left blank)

Executive Summary

The Climate and Equitable Jobs Act (CEJA) was passed by the Illinois General Assembly and signed into law by Governor Pritzker as Public Act 102-0662 on September 15, 2021. CEJA established a series of important changes to Illinois energy policy, including an overhaul to the Illinois Renewable Portfolio Standard (RPS), creation of a statewide policy target of 100% clean energy by 2050, targeted reduction of greenhouse gas (GHG) emissions from fossil generation facilities, incentives to promote electric vehicle adoption and reduce transportation sector fuel emissions, support for at-risk zero emission nuclear plants, financial support for communities faced with generation facility closures, financial support for clean energy workforce programs, and new equity requirements and labor standards applicable to the clean energy economy. CEJA also amended Section 9.15(o) of the EPAct to require the completion of a Resource Adequacy Study (RA Study) that assesses the State's progress towards its renewable energy, green hydrogen technologies, and emissions reduction goals, along with the current and projected status of electric resource adequacy and reliability throughout Illinois with proposed solutions for any shortfalls that may be identified. In effect, this new provision implements a two-step process whereby (i) a RA Study is completed to determine if a resource adequacy shortfall is likely to occur given the current and projected state of the electric grid—communicated through the issuance of a report,[1] and (ii) if such a shortfall is projected, a mitigation plan is completed to assess options to address the projected shortfall.

This Resource Adequacy Study was developed through a coordinated effort among the Illinois Commerce Commission (ICC), the Illinois Power Agency (IPA), and the Illinois Environmental Protection Agency (IEPA), collectively "the Agencies." The Agencies have prepared this report in response to the directive under Section 9.15(o) of the Illinois Environmental Protection Act (EPAct).

The Agencies utilized the services of the IPA's Procurement Planning Consultant, Energy and Environmental Economics, Inc. (E3), to conduct the analysis and support the overall process and development of the RA Study. The Agencies also conducted engagement with stakeholder groups, the RTOs, and Illinois utilities. The Agencies coordinated with PJM and MISO to verify modeling assumptions and seek guidance on available data resources and coordinated with the Illinois utilities to inform the treatment of load forecasts and cross-reference approaches with other utility-driven studies. This collaborative structure ensured

[1] The RA Study report is to be issued publicly and delivered to the Illinois General Assembly and Governor's Office.

that the study was grounded in the best available data and reflected current market developments.

Resource Adequacy Context for Illinois Consumers

Resource Adequacy (RA) evaluates whether there is sufficient electricity supply available to meet corresponding customer demand in all hours with a defined level of certainty. This is a critical concept for electricity system planning, which evaluates how future resource portfolios meet policy, affordability, and reliability objectives. No electric system is "perfectly reliable"—meaning that there is a zero percent chance of a loss of load event. Electric systems are instead designed to achieve a specific reliability standard which represents an acceptable probability of lost load over a range of possible conditions while balancing the feasibility and costs of meeting this target with available technologies.

Illinois was one of many states to restructure its electric industry during the late 1990s and early 2000s to create competition in retail electricity service. In practice, restructuring shifted the day-to-day responsibility for organizing resource adequacy from vertically integrated utilities to the regional transmission organizations (RTOs) such as PJM and MISO, which provide two primary functions: i) system operations including generation dispatch and control of the high-voltage transmission system, and ii) market operations including the design, implementation, and settlement of wholesale market prices and transactions for energy, ancillary services, and capacity. PJM and MISO design and administer capacity markets as the primary mechanisms by which resource adequacy is assessed, measured, and compensated within each regional market.

Customers in Illinois are served by several types of Load-Serving Entities (LSEs): municipal utilities, electric cooperatives, Alternative Retail Electricity Suppliers (ARES), and electric utilities, including electric utilities that that rely on the IPA to procure supply for default service for customers who do not select an ARES for service. Under the market structure of retail competition in Illinois, the costs of supplying customers with electricity are backstopped by the RTO wholesale markets through locational marginal prices (LMPs) for energy and by capacity market prices in each RTO zone in Illinois. In a competitive equilibrium, which is typically assumed for studies of this nature, retail customers in Illinois can expect to pay the wholesale market price for energy and capacity in their market zone.

For eligible retail customers—defined as the residential and small commercial customers of Ameren, ComEd, and MidAmerican who have not switched to an ARES or enrolled in real-time pricing—the IPA determines, through its annual Electricity Procurement Plan, how to procure the capacity obligations needed to serve such customers. The IPA, and by extension the utilities, currently utilize different approaches to secure capacity for these residential and small commercial customers, along with hourly pricing default service customers. Through the 2025 Electricity Procurement Plan, the IPA has only sought to secure a capacity hedge on behalf of Ameren customers. Subject to the terms of the IPA Electricity Procurement Plan, any capacity obligations not secured through an IPA electricity procurement event are acquired by the utilities through the MISO Planning Resource Auction (PRA). ComEd currently secures all capacity obligations for default service customers through the PJM Base Residual Auction (BRA). For default service customers on hourly pricing service, Ameren or ComEd procure capacity through the MISO PRA or PJM BRA, respectively, and pass those costs on directly to customers. ARES are responsible for meeting the energy and capacity needs of their customers. For MidAmerican, the level of exposure to capacity markets faced by eligible retail customers is negligible.

Municipal electric utilities and rural electric cooperatives are load serving entities and thus responsible for the capacity obligations of their customers. Unlike Ameren and ComEd, municipal utilities and cooperatives either own generation or enter into contracts with generators for resource adequacy.

The different mechanisms and different types of LSEs in Illinois contribute to challenges in managing future resource adequacy in the state. Each entity is focused on serving the immediate needs of its own customers, not in concert with each other, resulting in a patchwork of approaches by LSEs that make it difficult to plan for long-term resource adequacy needs. For example, an ARES cannot guarantee what its market share will be over time—the ARES may gain or lose customers. As a result, there is an inherent risk for an ARES to enter long-term capacity contracts. Similarly, the IPA has hedged capacity for Ameren Illinois eligible retail customers to manage price volatility in the MISO capacity auction rather than carry any long-term capacity commitments. Like an ARES, the IPA must consider the risk of customers switching prior to determining the amount of capacity to hedge.

It can be challenging under the Illinois market construct to make any long-term commitments that could have an impact on changing the resource adequacy paradigm. Capacity prices are difficult to forecast with MISO utilizing a prompt auction format and PJM's forward auction format only providing a three-year outlook. PJM and MISO have engaged in a series of reforms to their capacity market constructs, creating a cycle of continuous changes to their market rules which adds additional risk and uncertainty. The recent passage of the Clean and Reliable Grid Affordability Act (CRGA) holds numerous opportunities to potentially adjust the current paradigm, including provisions surrounding the completion of an Integrated Resource Plan (IRP) and providing the IPA with a potential pathway to complete long-term clean capacity procurements on behalf of all customers instead of just default service customers. However, the mechanics of these provisions and numerous others are pending development and implementation.

Resource Adequacy Study Approach and Methodology

The principal objective of this report is to assess resource adequacy for Illinois consumers over an appropriate planning horizon. The development of new electric supply resources typically takes five to seven years,[2] with certain kinds of resources and critical grid infrastructure expected to require even longer timelines, including transmission, which can often take ten years or more to develop.[3] Accordingly, this report includes an assessment of reliability needs in MISO, PJM, and Illinois from 2026 through 2045 to inform how resource adequacy needs may change as the load and generation mix evolves in these regions. Many actions taken today effect resource development, retirement, or extension, have longer term and cascading impacts on reliability, costs, and the broader energy landscape, thereby affecting future actions. Therefore, it is important to assess near-term resource adequacy needs amidst the context of a longer time horizon to inform decision-making.

Assessing resource adequacy risk requires answering three principal questions:

1. What is the expected reliability requirement over the resource adequacy evaluation period?
2. How will the projected mix of existing and future resources contribute to the expected reliability requirement?
3. What are the risks to achieving resource adequacy for Illinois in the future?

To address these questions, two complementary analyses were undertaken in this study: an assessment of resource adequacy needs and risk in the near-term to medium-term (2026 through 2035), and an analysis of how resource adequacy needs are expected to evolve for Illinois within the context of the broader regional markets over a longer time horizon from 2030 through 2045.

To assess resource adequacy needs and risk in the near-term, the study team projected resource adequacy balances for PJM, MISO, and relevant Illinois zones from 2026 through 2035. These projections assess whether expected supply will be sufficient to meet projected demand, given identified major drivers of risk and uncertainty in the near term. The model

---

[2] "Queued Up: 2024 Edition — Characteristics of Power Plants Seeking Transmission Interconnection As of the End of 2023," Lawrence Berkeley National Laboratory (April 2024): https://emp.lbl.gov/publications/queued-2024-edition-characteristics.

[3] "Power Delayed: Economic Effects of Electricity Transmission and Generation Development Delays," Resources for the Future, Working Paper No. 25-14 (May 2025): https://www.rff.org/publications/working-papers/power-delayed-economic-effects-of-electricity-transmission-and-generation-development-delays.

begins with peak load forecasts from PJM, MISO, Ameren Illinois, and ComEd for each year, and builds a supply stack that includes the existing resource fleet, adjusted for announced retirements and new capacity that is projected to be online based on interconnection queue data. The study team assessed the risk of achieving near term resource adequacy targets based upon the uncertainties and risk factors governing load growth, new resource development, and resource retirements.

E3's portfolio analysis addressed resource adequacy from 2030 through 2045. The analysis involved simulating forward-looking resource needs and effective load carrying capabilities (ELCCs) of existing and future resources in MISO and PJM and then modeling resource portfolios that could meet the future system's resource adequacy requirements under different scenarios. E3 assessed the risks of achieving long term resource adequacy by examining the feasibility and potential challenges of developing one or more resource adequate portfolios under current regulatory, policy, and market structures.

Findings on Near-Term Resource Adequacy (2026-2030)

The capacity market auctions run by PJM and MISO are forward-looking assessments of the supply and demand balances in each region, representing the best available data on near-term reliability needs and capacity contributions by all resources in the current system. Based on the latest auction results in both markets (PJM 2026/2027 BRA and MISO 2025/2026 PRA), both PJM and MISO (and by extension, Illinois zones) are resource adequate today to meet the RTOs' reliability standards of a loss of load event occurring at most one day in ten years.

Table 1: Capacity Auction Results for PJM (2026/2027) and MISO (2025/2026)

	PJM 2026/2027 BRA	MISO 2025/2026 PRA
Capacity Balance	PJM secured 134,311 MW of unforced capacity (UCAP) through the auction, plus 11,933 via Fixed Resource Requirement (FRR) commitments, totaling 146,244 MW. Total resources exceeded the RTO-wide target of 146,105 MW by 138.8 MW (0.1%).	137,559.3 MW cleared for the summer season, including 19,947 MW contributed by Fixed Resource Adequacy Plan (FRAP) participants. Total resources exceeded the RTO-wide target of 135,213.4 MW by 2,345.9 MW (1.7%).
Reserve Margins	The BRA cleared at 18.9% reserve margin, slightly below the 19.1% target.	Summer: 9.8% cleared vs. 7.9% target Fall: 17.5% cleared vs. 14.9% target Winter: 24.5% cleared vs. 18.4% target Spring: 26.8% cleared vs. 25.3% target
Clearing Prices	PJM-wide capacity prices hit the FERC-approved cap of $329.17/MW-day in all market zones.	Annual Average: $217/MW-day (North/Central) and $212/MW-day (South)

However, resource adequacy margins in both regions are becoming increasingly constrained due to load growth, thermal generator retirements, and updates to resource adequacy market structures, including the resource accreditations for renewable, storage, and thermal resources. Data centers are the primary driver of load growth in the latest forecasts from utilities and the RTOs,[4] with load growth projections at levels well above those observed in either market over the past twenty years. Combined with an aging fleet of coal and gas generators, this load growth is likely to pose significant challenges for the reliability of both systems. The latest auctions in PJM and MISO each set record high capacity prices, providing an incentive for new resource development and the retention of existing generation as reliability margins become tight. While this price signal is designed to support resources needed for system reliability, it also increases costs to consumers.

Based on current load forecasts and resource adequacy targets, both PJM and MISO are projected to face capacity shortfalls over the coming decade unless additional new capacity resources are developed. PJM's resource adequacy target increases by approximately 20% between 2025 and 2030, while MISO's target grows by around 10% over the same period, driven primarily by rapid, concentrated load growth from data center development in addition to load growth from residential and commercial customers. Both RTOs have significant volumes of new capacity in development—nearly 87 GW in PJM and over 72 GW in MISO of new nameplate capacity by 2030.[5] However, most of these new resources are variable and intermittent renewable energy projects, and when adjusted for accredited capacity these additions amount to 27 GW in PJM and 28 GW in MISO.[6] At the same time, accredited capacity retirements are projected to reach nearly 15 GW in PJM and 18 GW in MISO, primarily consisting of aging thermal generators.[7] When accounting for these supply and demand dynamics, including announced retirements by generators in Illinois and within each RTO market and accredited new builds currently in the queue or fast-tracked through the PJM RRI or MISO ERAS programs,[8] PJM is expected to experience a capacity shortfall beginning in 2029, with the deficit projected to widen in subsequent years if left unabated. MISO remains resource adequate through 2030, but a shortfall is projected to emerge in 2031 and grow thereafter. These projections reflect baseline conditions "as reported" from

---

[4] See Section 4.2.1 for more detail on load growth projections.

[5] Data from Velocity Suite and RTO Interconnection Queues, inclusive of projects in the PJM Reliability Resource Initiative (RRI) and MISO Expedited Resource Addition Study (ERAS) queues.

[6] Capacity accreditations by resource type for existing resources, new additions, and retirements in the load-resource balance model are all based on published values from PJM and MISO. See Section 4.2.3.1 for details.

[7] Retirements are based on announcements by plant owners as reported by Velocity Suite, in addition to assumed retirements in Illinois to meet CEJA emissions requirements by 2030.

[8] The PJM RRI and MISO ERAS initiatives are fast-track interconnection processes for projects which have been selected by the RTOs for expedited development to meet reliability needs.

each data source used, with the projections assuming no acceleration or delays in new resource development or retirements.

Figure 1: PJM RA Balance (2026-2035) | Resource Additions and Retirements "As-Reported"

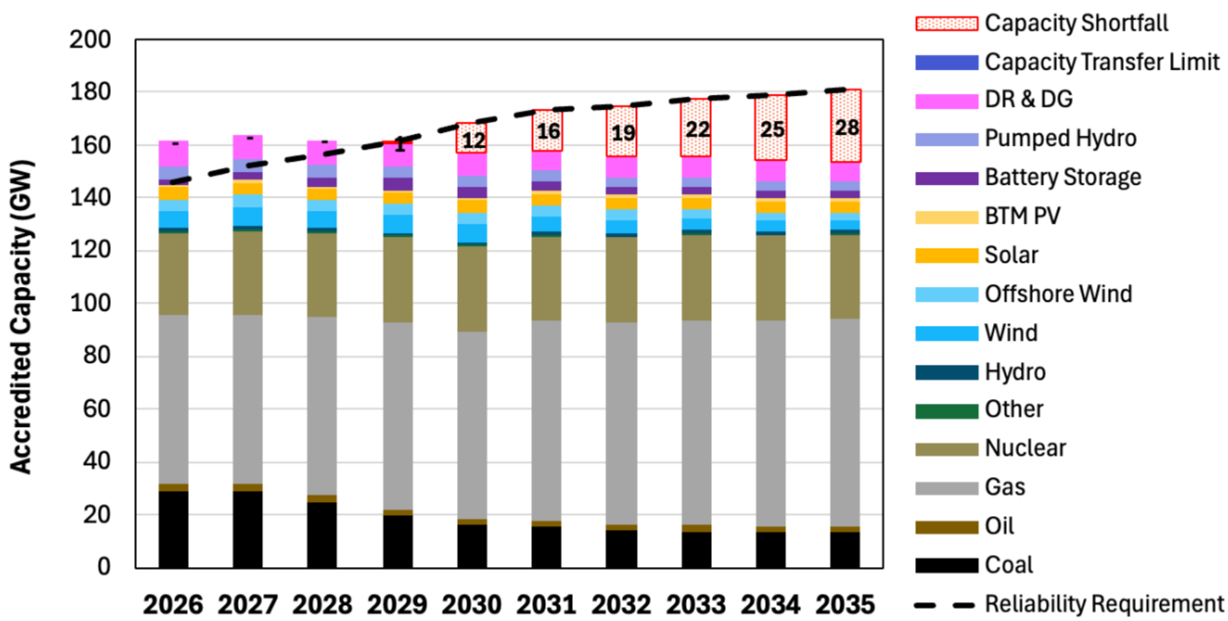
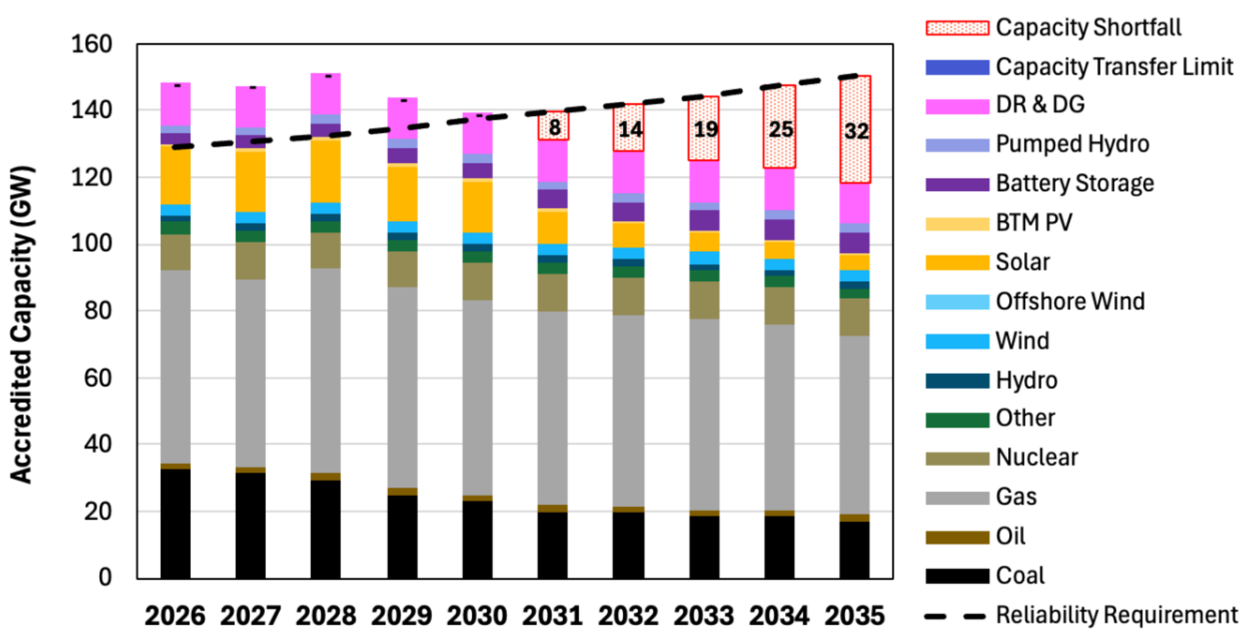


Figure 2: MISO RA Balance (2026-2035) | Resource Additions and Retirements "As-Reported"



The preceding results summarized in Figure 1 for PJM and Figure 2 for MISO illustrate the broader system-wide supply and demand conditions across both markets through 2035. Using the same analytical approach, resource adequacy throughout Illinois was also evaluated, focusing on the PJM ComEd zone and MISO LRZ 4 (the primary Illinois zone in MISO). Both PJM and MISO conduct zonal resource adequacy assessments as part of their capacity market structures to ensure that each zone has access to sufficient deliverable capacity. These zonal assessments are informed by transmission transfer capabilities, specifically the Capacity Emergency Transfer Limit (CETL) in PJM and the Zonal Import Ability (ZIA) in MISO, which define how much capacity can reliably flow into each zone from the rest of the system during critical hours.

This analysis incorporates these transfer limits to evaluate whether Illinois' zones meet their reliability requirements, as shown in Figure 3 and Figure 4 below. However, it is important to note that these metrics assume the broader RTO has sufficient surplus capacity available to support these transfers. If the RTO is short on capacity, as established in the previous section, Illinois cannot rely on imports from neighboring zones to maintain resource adequacy. In that context, system-wide resource adequacy is a prerequisite for zonal RA balances to be meaningful. Even if a zone appears to meet its internal planning requirement, it will remain exposed to the consequences of a regional shortfall, including capacity price spikes, transmission line congestion, and elevated loss of load risk.

Under conditions where new resources are in-service according to their reported commercial operation dates and RTO-wide retirements proceed as planned, the resource adequacy outlooks for these two Illinois zones diverge notably. The ComEd zone meets its zonal requirements through 2032 but begins to rely on imports from the broader PJM system via the CETL starting in 2030. Projected load growth in the zone drives a 24% increase in resource adequacy requirements between 2025 and 2030, which contributes to growing dependence on external capacity even before the onset of an outright shortfall in 2032.

In contrast, MISO LRZ 4 meets its zonal requirements through 2035. The zone experiences a more modest increase in its resource adequacy requirement (approximately 11% from 2025 to 2030) and there is sufficient in-zone accredited capacity to meet the zone's needs through 2030 before beginning to rely on imports through 2035. Even when the MISO LRZ 4 zonal capacity balance appears sufficient, emerging reliance on interzonal transfers and the MISO-wide results indicate a risk of shortfall at the system level, which poses a corresponding resource adequacy risk for Illinois consumers.

These projections for the ComEd and MISO LRZ 4 zones assume that coal, oil, and gas-fueled generators in Illinois are retired in alignment with emissions limits enacted through CEJA and applicable to future years beginning in 2030.

Figure 3: PJM ComEd Zone RA Balance (2026-2035) | Resource Additions and Retirements "As-Reported"

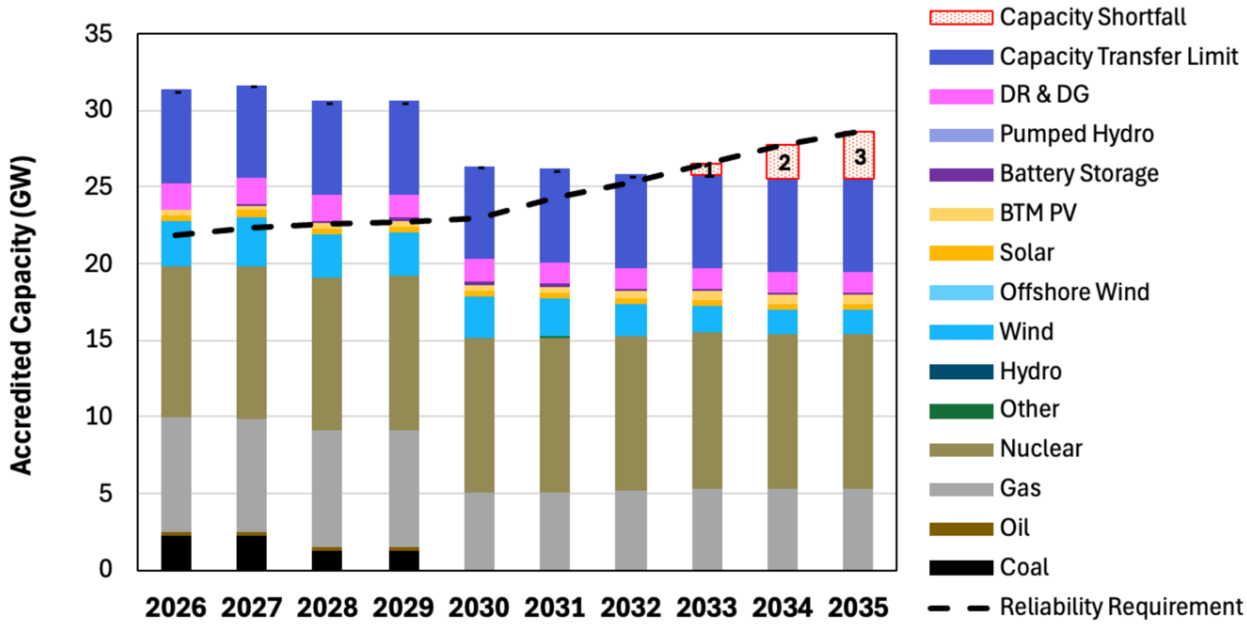
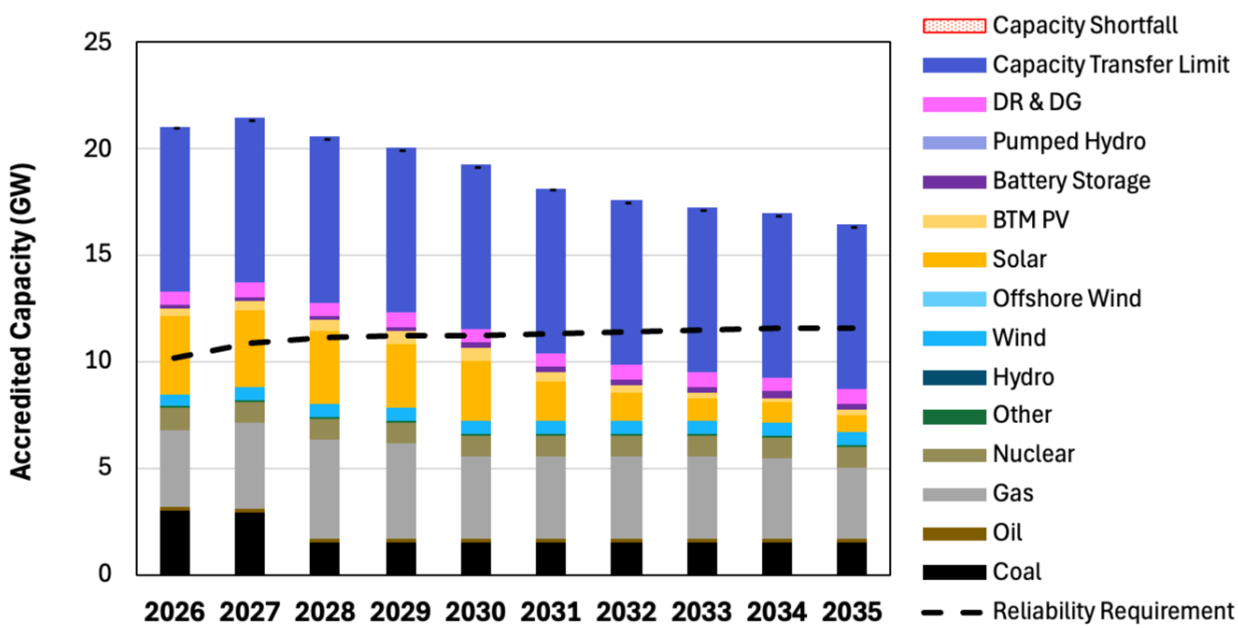


Figure 4: MISO LRZ 4 RA Balance (2026-2035) | Resource Additions and Retirements "As-Reported"



Taken together, the resource adequacy balance projections indicate that Illinois faces a resource adequacy risk over the coming decade—not because the local Illinois zones are structurally deficient under baseline assumptions, but because both PJM and MISO are projected to face sustained system-wide capacity shortfalls in the presence of rapid, data center-driven load growth, changing market structures and associated accreditation methodologies, and the absence of additional new resource development beyond those projects already in RTO interconnection queues.

As explained below, under scenarios with development timelines that incorporate delays in bringing new resources online, both PJM and MISO and the ComEd and LRZ 4 zones experience tighter conditions sooner. And while scenarios with limited in-state retirement deferrals modestly improve the resource adequacy balance in Illinois, they do not meaningfully change the outcome: resource adequacy in Illinois is fundamentally constrained by the availability or scarcity of surplus capacity in PJM and MISO.

Findings on Longer-Term Resource Adequacy Needs (2030-2045)

Building on the assessment of near-term resource adequacy through supply and demand projections, this study also explores how Illinois and the broader RTO systems might maintain reliability through 2045 under continued load growth and decarbonization policies along with changing resource economics. This long-term analysis is informed by capacity expansion modeling to identify various potential resource portfolios which could meet the evolving resource adequacy needs of PJM, MISO, and the Illinois market zones. A loss-of-load probability model is also used to project resources' ELCCs into the future as an input to the portfolio analysis and to ensure that the selected portfolios meet the RTOs' reliability standards of a 1-day-in-10-year loss of load expectation. This modeling approach identifies least-cost, policy-compliant long-term portfolios that can help inform near-term decisions and policy recommendations around resource adequacy in the context of future system dynamics and requirements.

The modeling framework implemented for this study relies on the interplay between capacity expansion and resource adequacy models:

Resource Adequacy: RECAP[9] identifies total effective capacity needed for resource adequacy and evaluates each resource's contribution towards meeting that need through extensive simulations of load and weather conditions.

[9] RECAP is an E3 in-house loss-of-load probability (LOLP) model; it has been used by utilities and system operators across North America.

Capacity Expansion: PLEXOS[10] is used to optimize generation and transmission portfolios to minimize cost while satisfying policy and resource adequacy constraints.

RECAP calculates Total Reliability Need (TRN) and Planning Reserve Margin (PRM) values that ensure sufficient effective capacity is built in each market, along with market- and technology-specific curves that relate the marginal Effective Load Carrying Capabilities (ELCCs) of each resource type to its total penetration (MW) in the system. These curves are then used to constrain the PLEXOS model's resource selection to meet the TRN in each market and each projection year at the lowest total cost. Together, these models ensure portfolios are cost-optimal, reliable, and compliant with policy targets. The same models and assumptions are also used in the Illinois 2025 Draft Renewable Energy Access Plan (REAP), ensuring analytical consistency between the two studies which have complimentary focus and objectives. This is also the same fundamental modeling framework used as a 'best practice' in Integrated Resource Planning (IRP) processes across North America, including those supported directly by E3.

Evaluating future resource adequacy needs requires understanding how system conditions may evolve under uncertainty. To capture a wide range of possible futures, this study uses a scenario framework to evaluate how these uncertainties impact system reliability and the types of resources needed to maintain resource adequacy over time. Table 2 provides an overview of the key scenario drivers utilized in modeling.

Table 2: Key Scenario Drivers

Scenario Driver	When included	When excluded
New Illinois Gas Allowed	New gas combustion resources are allowed to be developed in-state	No new gas resources can be constructed in Illinois
CEJA Retirement Extension	Thermal plant retirements under CEJA emissions standards do not occur by 2045[11]	Thermal plant retirements under CEJA occur as scheduled
Illinois Net Zero Emissions	Illinois must achieve net-zero carbon emissions by 2045[12]	Illinois does not have a 2045 net zero emissions target
Low Battery Costs	Optimistic costs for new battery storage projects are assumed	Base costs for new battery storage projects are assumed

[10] PLEXOS is a commercially available capacity expansion and production simulation modeling software developed by Energy Exemplar; it is used by utilities and system operators across North America, and it is the model currently used by MISO and PJM. For more information, see: https://www.energyexemplar.com/plexos.
[11] Non-CEJA-driven retirements in Illinois still occur as planned.
[12] Net-zero emissions are achieved by requiring all in-state gas generation to convert to a zero-carbon fuel by 2045, as well as requiring Illinois to be a net exporter of energy in 2045.

The Base Case serves as a central reference point, reflecting a continuation of current law, state policies, and development trends. Other cases apply combinations of scenario drivers to examine how Illinois state policies (such as extending CEJA retirement deadlines or disallowing new in-state gas generation), meeting deeper decarbonization targets, and a low battery cost trajectory affect selected resource portfolios. Table 3 provides the concatenation of the modeling cases used in this RA Study relative to the drivers as summarized in Table 2. Each modeling case considered a different mix of predominant drivers as a means to derive meaningful and comparable results.

Data inputs for the portfolio modeling exercises in RECAP and PLEXOS were drawn from the best-available sources, including the RTOs, Illinois utilities (ComEd and Ameren), and third-party databases. Data inputs included existing generation resources and characteristics, load shapes, renewable generation profiles, generator retirements, new resources in development, new resource costs, load projections, and transmission limits by modeled zone. More information on the modeling methodology and key assumptions and inputs is detailed in Chapter 5 and in the Appendices to this study.

Table 3: Scenario Matrix

Modeling Cases	New Illinois Gas Allowed	CEJA Retirement Extension	Illinois Net Zero Emissions	Battery Costs
Base Case	Yes	No	No	Base
CEJA Extension	Yes	Yes	No	Base
No New Illinois Gas	No	No	No	Base
CEJA Extension, No New Illinois Gas	No	Yes	No	Base
Illinois Net Zero	Yes[13]	Yes	Yes	Base
Low Battery Costs	Yes	Yes	No	Low

Key Findings from Portfolio Analysis

Figure 5 and Figure 6 below summarize the accredited (ELCC-adjusted) capacity by technology in the Base Case scenario for PJM and MISO. These figures are inclusive of Illinois capacity. These results illustrate the growing capacity need between 2030 and 2045 in both

[13] New combustion equipment can still be selected, but all in-state gas generation is assumed to run on zero-carbon fuels by 2045.

RTOs. In PJM, roughly 25 GW of effective capacity additions are needed over the modeling horizon just to meet load growth, while additional capacity is needed to replace the planned retirements of large coal and gas generators. The 20 GW of Li-ion battery additions provide roughly 15 GW of effective capacity in 2030, but most additional incremental capacity additions through 2045 are gas generators—either simple cycle combustion turbines (CTs) or combined cycle gas turbine (CCGT) units.

MISO has a larger capacity need in 2030 relative to its peak load compared to PJM, and large volumes of batteries are selected in the Base Case scenario by 2030 to meet the PRM. However, starting in 2035, CCGTs emerge as the predominant new capacity resource added to the system. Since MISO has higher penetrations of renewable energy and battery storage compared to PJM, and consequently does not need as much additional generation, by the 2040s some additional combustion turbine (CT) peaking capacity is added.

Figure 5: PJM Total Accredited Capacity (GW) | Base Case

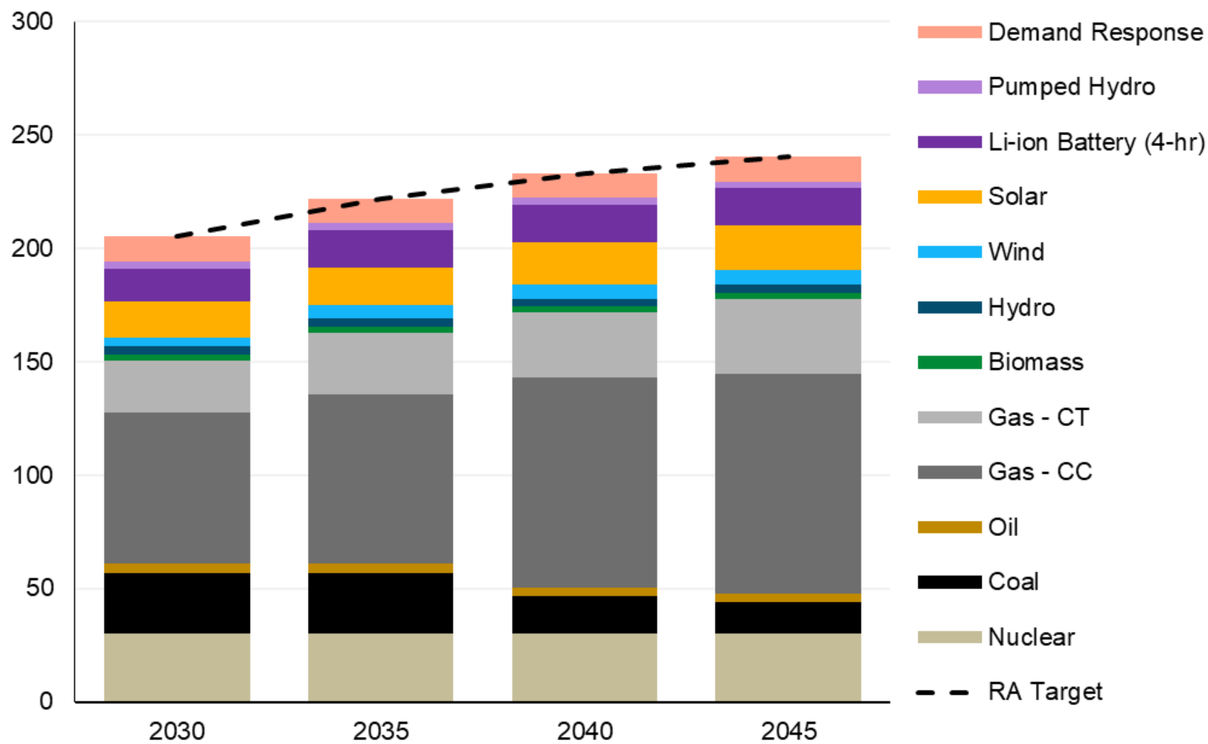
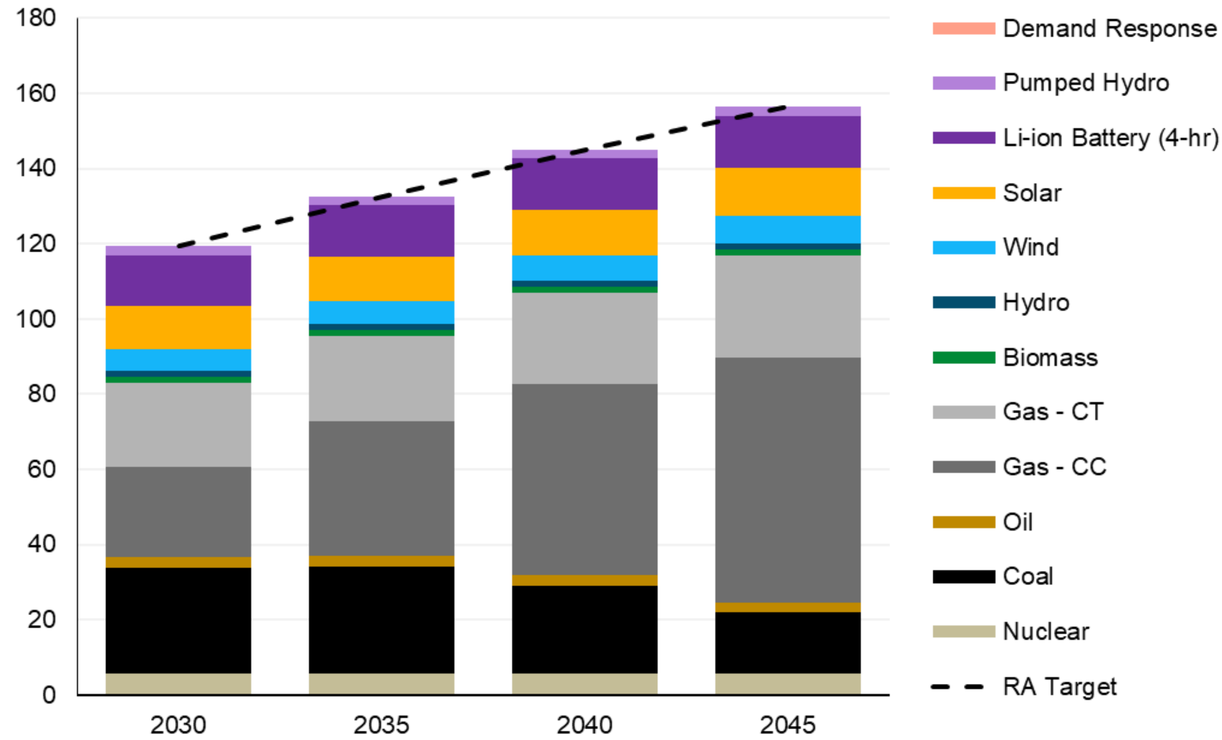


Figure 6: MISO LRZs 1-7 (North/Central) Total Accredited Capacity (GW) | Base Case



The figures below summarize the selected capacity additions and capacity contributions by technology in MISO LRZ 4 and the ComEd zone of PJM for the Base case. These results underscore the differences between MISO LRZ 4, a renewables-rich supply zone with ample interregional transmission access and moderate load growth, and the ComEd zone, a supply- and transmission-constrained region that must procure larger volumes of effective capacity to meet growing load and replace retiring fossil generators. While MISO LRZ 4 does experience load growth and CEJA-driven generator retirements throughout the modeling horizon, its zonal reliability targets within the MISO market can be met by importing capacity from neighboring regions without exceeding the modeled transmission limits. The base case portfolio includes roughly 1 GW of Li-ion batteries in the Ameren zone by 2030, as the model sees batteries as cheaper than out-of-state gas for incremental capacity. As CEJA-impacted generators are decommissioned and replaced with capacity imports, the in-state accredited capacity total falls by 2045 to nearly half of its 2030 value.

In the ComEd zone, the compounding effects of load growth, CEJA-driven retirements, and import capability limits paint a different picture. In 2030, in addition to 2 GW of new Li-ion batteries, the model decides to use the entire available transmission import rating of the ComEd zone to meet the resource adequacy requirements. In later years, new in-state gas CT units are selected to replace retiring CEJA-impacted generators and maintain local reliability within the zone. After 2030, some additional wind resources are selected in the ComEd zone to provide low-cost energy generation, complementing the large volumes of resources selected purely for their capacity contribution. By 2045, the firm capacity previously provided by CEJA-impacted generators is entirely replaced by new in-state CTs (assumed to comply with zero-emissions standards through use of alternate fuels such as green hydrogen) and capacity imports.

The Base Case resource portfolio replaces existing in-state fossil fuel generation with over 13 GW of new in-state combustion turbines (CTs) and 18 GW of out-of-state capacity imports to meet local reliability requirements, while also adding roughly 11 GW of solar and 13 GW of wind in Illinois to meet the 50% RPS target by 2045. Figure 7 and Figure 8 below present the model-selected new resource builds in the ComEd zone and MISO LRZ 4—these builds are stated in cumulative nameplate capacity (GW) by resource type. All of the new in-state combustion turbines are built in the ComEd zone in the Base Case because the projected load growth (and reliability requirement) of the ComEd zone exceeds the sum of accredited capacity from existing generators and the import capability of the zone. In contrast, MISO LRZ 4 has much more transmission import capability and less load growth compared with the ComEd zone, and the model elects to use the transmission limits to import capacity from outside LRZ 4 to meet the reliability target while building solar and wind in the zone to meet Illinois renewable energy targets.

Figure 7: ComEd Zone Cumulative Selected New Resource Builds (GW) | Base Case

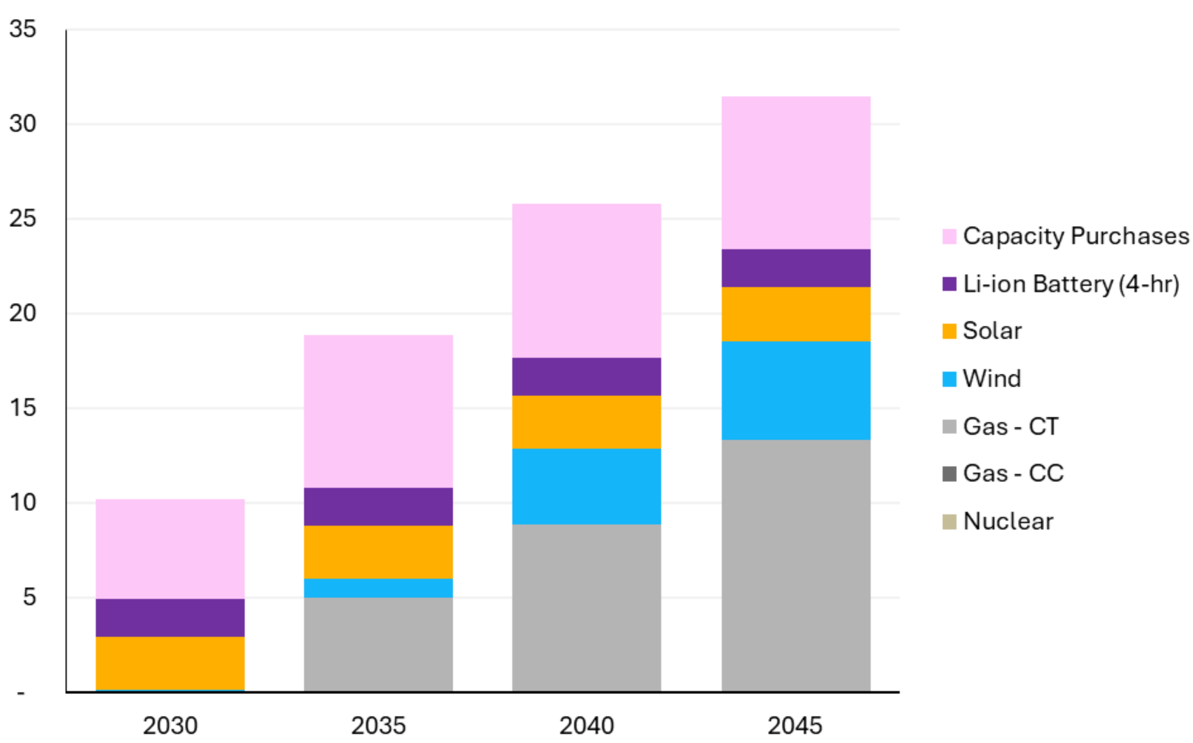


Figure 8: MISO LRZ 4 Cumulative Selected New Resource Builds (GW) | Base Case

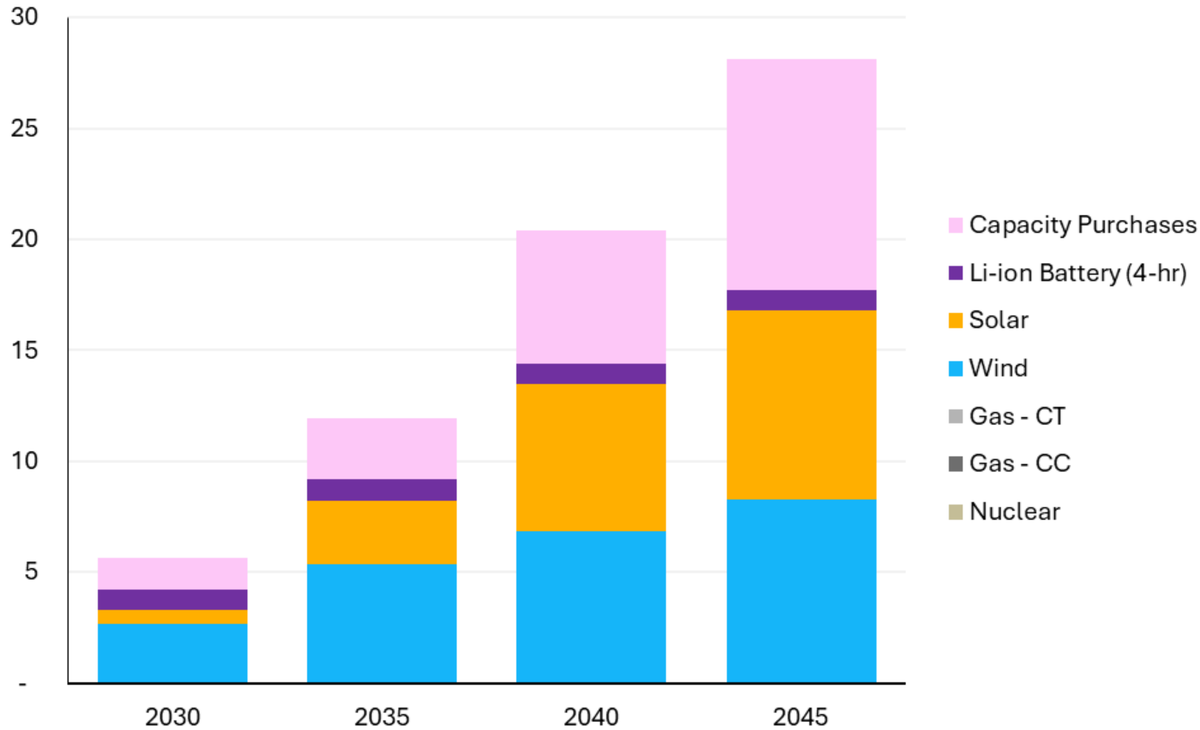


Figure 9 and Figure 10 present how existing resources, planned resources, model-selected new resources, and transmission import capabilities combine as total accredited capacity to meet the reliability requirements projected for the ComEd zone and MISO Zone 4 in the Base Case.

Figure 9: ComEd Zone Total Accredited Capacity (GW) | Base Case

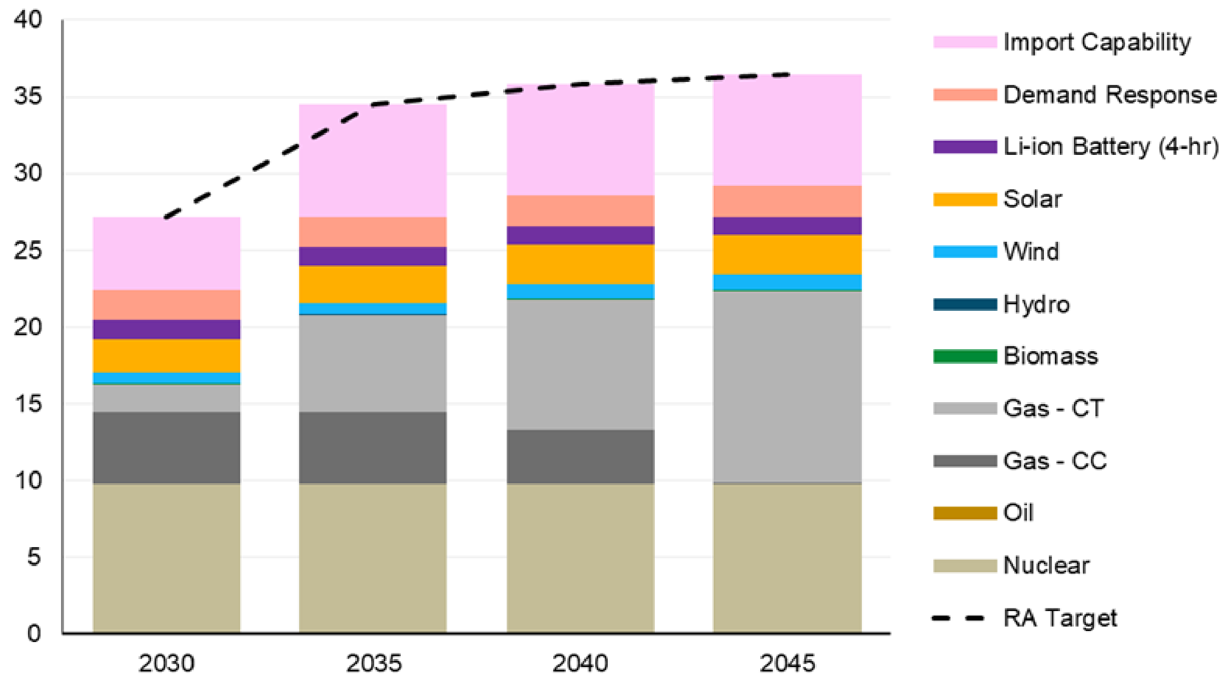
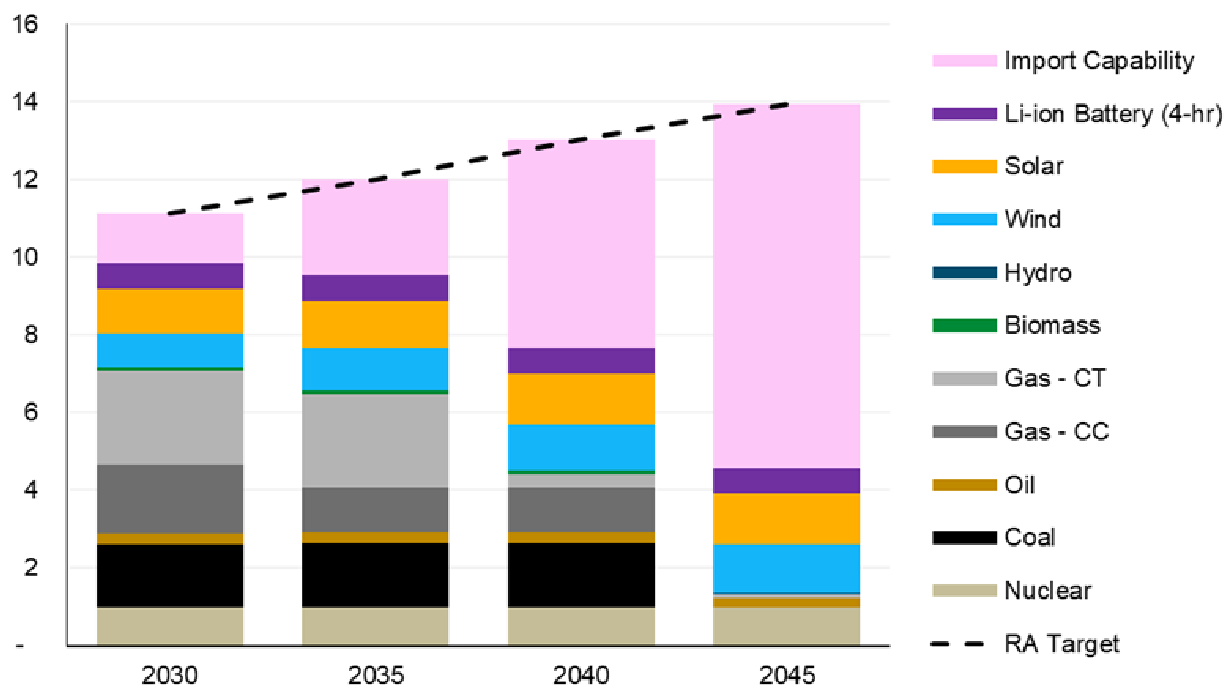


Figure 10: MISO LRZ 4 Total Accredited Capacity (GW) | Base Case



The Base Case portfolio modeling results illustrate one potential path forward by which Illinois could meet its evolving resource adequacy needs and its decarbonization and clean energy targets established by CEJA and other state policies through 2045. The resource mix involves a combination of new wind, solar, and battery storage alongside new gas-fired combustion turbines that use non-emitting fuels after 2045. New renewable energy resources drive carbon emissions savings while batteries, new gas turbines, and imports from the broader regional markets provide reliability during critical hours. Figure 11 and Figure 12 below illustrate the generation mix in the ComEd and LRZ 4 zones for the Base Case resource portfolio in the PLEXOS modeling.

Figure 11: ComEd Zone Annual Generation 2030-2045 (TWh) | Base Case

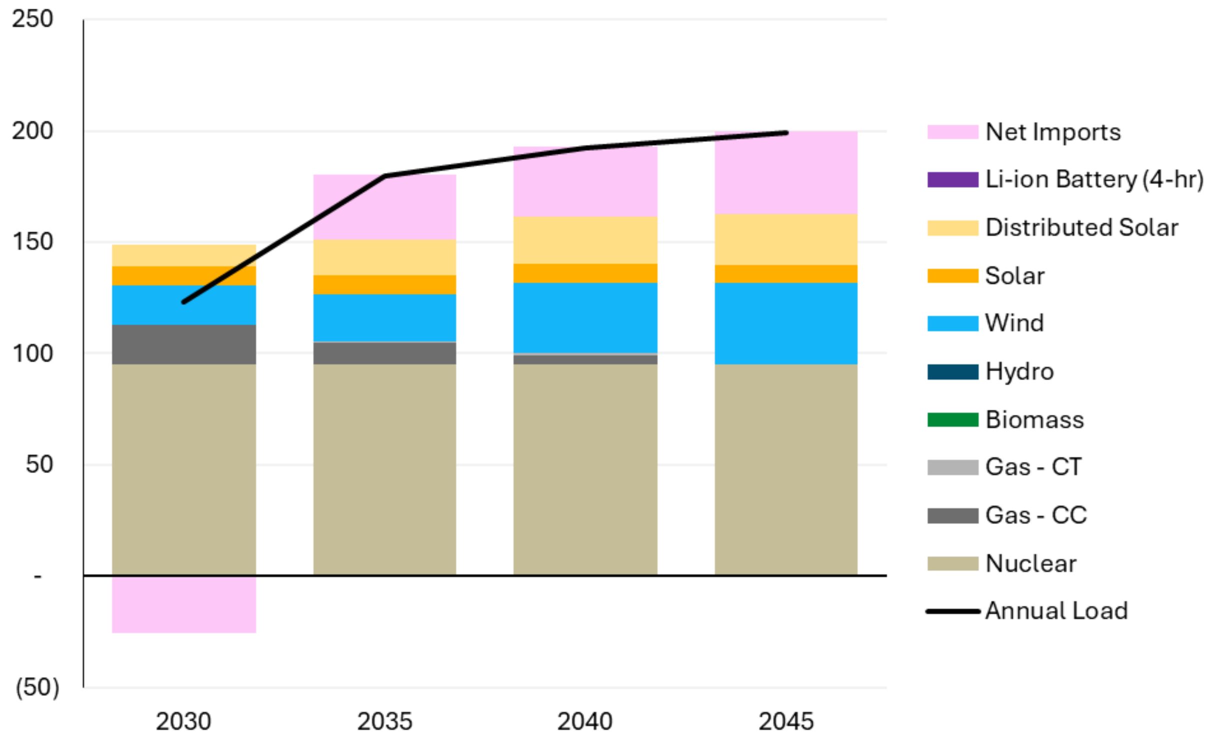
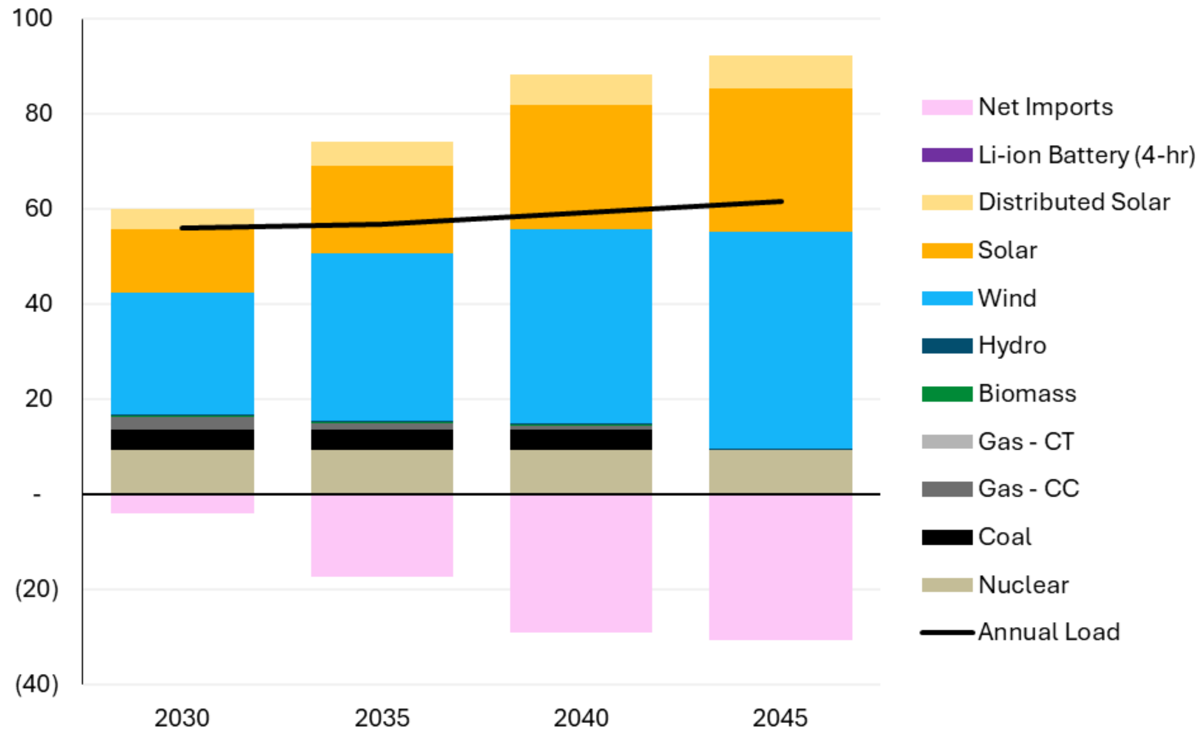


Figure 12: MISO LRZ 4 Annual Generation 2030-2045 (TWh) | Base Case



Other scenarios considered within this study illustrate the durability of this finding—that thermal generation is an important source of resource adequacy along with new battery storage resources, while new renewable energy resources (wind and solar) can continue to drive reductions in carbon emissions from electrical energy consumed in Illinois. The scenarios evaluated in this study do not constitute an exhaustive or comprehensive set of potential scenarios Illinois may face in the future, nor do these portfolio results by themselves indicate a required resource trajectory for the state. The Base Case scenario and others presented in this report are intended to provide an illustration of the nature of the challenges that Illinois faces with resource adequacy and clean energy targets in the future and provide constructive guidance on the nature of the potential resource solutions to meet these challenges. More comprehensive portfolio analysis and additional scenarios will be an important component of any forward planning or procurement for Illinois in the future, including a future Integrated Resource Planning exercise.

Conclusions and Next Steps

Illinois has entered a period of significant transformation in its electric power system. Accelerating load growth, evolving RTO market conditions, state clean energy and climate policies, and challenges with new resource development collectively point to a tightening reliability outlook in the near and medium term. This Resource Adequacy Study, developed jointly by the IPA, ICC, and IEPA, assesses these dynamics, identifies the scale and timing of prospective challenges, and begins to establish a path to ensuring that Illinois can meet both its climate and reliability objectives. Based on extensive analysis of RTO conditions, state policy requirements, and forward-looking resource needs, several key findings emerge.

1. There are resource adequacy challenges in PJM and MISO which are likely to affect the costs and reliability of electricity supply for Illinois businesses and consumers.

The challenges emerge from a combination of factors at the regional and national scale. Load growth is accelerating, driven by data centers, transportation demand, and industrial expansion. At the same time, many coal, gas, and oil units are planned to retire across both RTOs due to age, economics, and emissions limits. New resource development also faces significant challenges. New gas generation faces long equipment lead times (5–7 years for gas turbines) and significant barriers to siting and permitting. Wind, solar, and storage projects face development challenges from long interconnection queues, transmission constraints, supply chain disruptions, tariffs, and domestic content requirements for tax credit eligibility. These conditions create a credible risk of regional capacity shortfalls that will impact Illinois' future ability to import power during critical hours and may cause reliability issues in Illinois even if Illinois market zones have enough capacity to meet their zonal RA requirements as determined by the RTOs.

2. There are pathways for Illinois to achieve its climate goals in the electricity sector while ensuring a reliable electric grid, using available commercialized technologies.

The state can successfully navigate both near-term reliability risks and longer-term decarbonization goals through a diversified resource strategy. This includes combining continued growth of new in-state wind and solar supported by IPA procurements and programs, greater use of existing and planned transmission to import power from MISO and PJM when available, and the continued use of fueled thermal generators as reliability assets even as their energy output declines with higher renewable penetration. This strategy also involves adding more short-duration battery storage and other flexible technologies to meet peak reliability needs, as well as developing new clean firm capacity resources to replace the reliability contribution provided by fossil generators in the long-term future, including long-duration storage and other emerging zero-emission technologies. The RA Study's analysis reinforces that substantial new capacity from renewable, storage, and clean firm resources will be needed even if Illinois retains a portion of its existing thermal fleet. New resource planning should also consider the potential contributions from demand-side measures, including energy efficiency and demand response—especially the potential load flexibility of new large loads such as data centers given the importance of these loads in the forecast.

3. Illinois has the responsibility, authority, and policy tools to conduct planning, identify solutions, and support implementing actions to address these challenges.

Following from the conclusions of this Report, IPA and IEPA will develop a Mitigation Plan that considers the use of renewable energy, energy storage, demand response, transmission development, or other strategies to resolve the identified resource adequacy shortfall as well as considering solutions involving the delays and/or reductions of CO_2e and co-pollutant emissions reductions requirements in the Section 9.15(o) the Illinois General Assembly passed the Clean and Reliable Grid Affordability Act (CRGA), which establishes a formal Integrated Resource Planning (IRP) framework for Illinois once signed into law. The new IRP process is expected to take place throughout 2026 and 2027, and it is intended to provide a more comprehensive venue for addressing many of the foundational issues identified through the RA Study within a unified, multi-year planning framework. As a result, the RA Study should be viewed as both an input to, and an early bridge toward, the prospective IRP process.

Both the RA Study and Mitigation Plan focus on the identification of key resource adequacy challenges and prospective solutions to those challenges, which can be evaluated in greater depth through IRP proceedings. The Agencies recognize that parallel processes addressing similar subject matter and requiring similar evaluations before the same forum is ripe for synergies, and the Agencies look forward to discussions with stakeholders on process alignment options.

In addition to the IRP and Mitigation Plan processes, Illinois is also conducting its Renewable Energy Access Plan (REAP) which is a rolling multi-year study of transmission needs to facilitate the development of new renewable energy resources in the state. Illinois continues to drive forward its renewable energy goals through programs and procurements directed by the Illinois Power Agency, and new mandates from CRGA would take effect on June 1, 2026, including planning and procurement processes for battery storage and potential proposals for other clean capacity resources.

Table of Contents

Table of Tables

Table of Figures

Table of Acronym Definitions

Acronym	Full Name / Definition
ARES	Alternative Retail Electric Supplier
BTM	Behind-the-Meter
BOEM	Bureau of Ocean Energy Management
BRA	Base Residual Auction
CC	Combined Cycle
CCGT	Combined-Cycle Gas Turbine
CEJA	Climate and Equitable Jobs Act
CEL	Capacity Export Limits
CETL	Capacity Emergency Transfer Limit
CETO	Capacity Emergency Transfer Objective
CIL	Capacity Import Limit
CMC	Carbon Mitigation Credit
CO2e	Carbon Dioxide Equivalent
CO	Carbon Monoxide
ComEd	Commonwealth Edison
CONE	Cost of New Entry
DAM	Day-Ahead Market
DC	Direct Current
DER	Distributed Energy Resource
DERs	Distributed Energy Resources
DR	Demand Response
DS	Distribution System
E3	Energy and Environmental Economics, Inc.
EGU	Electric Generating Unit
ELCC	Effective Load Carrying Capability
EPA	Environmental Protection Agency
EPAct	Environmental Protection Act (Illinois)
ERAS	Expedited Resource Addition Study
ERCOT	Electric Reliability Council of Texas
EUE	Expected Unserved Energy
EV	Electric Vehicle
FEJA	Future Energy Jobs Act
FEOC	Foreign Entity of Concern
FERC	Federal Energy Regulatory Commission

FRAP	Fixed Resource Adequacy Plan
FRR	Fixed Resource Requirement (PJM)
FY	Fiscal Year
GATS	Generation Attribute Tracking System
GHG	Greenhouse Gas
GWh	Gigawatt-hour
GW	Gigawatt
ICC	Illinois Commerce Commission
IEPA	Illinois Environmental Protection Agency
ILCS	Illinois Compiled Statutes
IPA	Illinois Power Agency
IRP	Integrated Resource Plan
ISO	Independent System Operator
LMP	Locational Marginal Price
LOLE	Loss of Load Expectation
LOLP	Loss of Load Probability
LSE	Load Serving Entity
LRZ	Local Resource Zone
MISO	Midcontinent Independent System Operator
MW	Megawatt
MWh	Megawatt-hour
NERC	North American Electric Reliability Corporation
NOx	Nitrogen Oxides
OMS	Organization of MISO States
OPSI	Organization of PJM States, Inc.
PA	Public Act
PJM	PJM Interconnection, LLC
PPA	Power Purchase Agreement
PRA	Planning Resource Auction
PRM	Planning Reserve Margin
PTC	Production Tax Credit
PUC	Public Utilities Act
PV	Photovoltaic Solar
RAA	Reliability Assurance Agreement
RA	Resource Adequacy
RAR	Resource Adequacy Requirement
RAS	Resource Adequacy Study
REAP	Renewable Energy Access Plan
RFP	Request for Proposals

RII	Resource Investment Initiative
RMR	Reliability Must-Run
RPS	Renewable Portfolio Standard
RTM	Real-Time Market
RTO	Regional Transmission Organization
SAC	Seasonal Accredited Capacity
SATOA	Storage as Transmission-Only Asset
SB	Senate Bill
SO2	Sulfur Dioxide
TRN	Total Reliability Need
UCAP	Unforced Capacity
US	United States
USEPA	U.S. Environmental Protection Agency
USWTDB	U.S. Wind Turbine Database
VOM	Variable Operations and Maintenance
VRR	Variable Resource Requirement
ZEC	Zero Emission Credit
ZIA	Zone Import Ability
ZRC	Zonal Resource Credit

1. Introduction

1.1. Purpose & Statutory Requirements

1.1.1. Illinois Environmental Protection Act (415 ILCS 5/9.15) Section 9.15(o)

The Climate and Equitable Jobs Act (CEJA) was passed by the Illinois General Assembly and signed into law by Governor Pritzker as Public Act 102-0662 on September 15, 2021. CEJA established a series of important changes to Illinois energy policy, including an overhaul to the Illinois Renewable Portfolio Standard (RPS), creation of a statewide policy target of 100% clean energy by 2050, targeted reduction of greenhouse gas (GHG) emissions from fossil generation facilities, incentives to promote electric vehicle adoption and reduce transportation sector fuel emissions, support for at-risk zero emission nuclear plants, financial support for communities faced with generation facility closures, financial support for clean energy workforce programs, and new equity requirements and labor standards applicable to the clean energy economy. CEJA also amended Section 9.15 of the Environmental Protection Act (EPAct) by adding subsection (o) which requires the completion of a Resource Adequacy Study (RA Study) that assesses the State's progress towards its renewable energy, green hydrogen technologies, and emissions reduction goals, along with the current and projected status of electric resource adequacy and reliability throughout Illinois with proposed solutions in the event a deficit is forecast. In effect, this new provision implemented a two-step process whereby (i) a Resource Adequacy Study is completed to determine if a resource adequacy shortfall is reasonably likely to occur given the current and projected state of the electric grid—communicated through the issuance of a report,[14] and (ii) if such a shortfall is projected as reasonably likely to occur, directs the development of a mitigation plan to assess options to address the potential shortfall.

The RA Study is to be jointly prepared by the Illinois Environmental Protection Agency (IEPA), Illinois Power Agency (IPA), and Illinois Commerce Commission (ICC), with the initial report due December 15, 2025. The IEPA, IPA, and ICC (herein referred to collectively as "Agencies") are required through statute to consult the two Regional Transmission Organizations (RTOs) with footprints in Illinois, PJM Interconnection, LLC and Midcontinent Independent System Operator, Inc. (MISO), regarding forecasted resource adequacy and reliability needs, anticipated new generation interconnection, new transmission development or upgrades, and any announced large GHG-emitting unit closure dates.

[14] The RA Study report is to be issued publicly and delivered to the Illinois General Assembly.

If the Agencies jointly conclude in the RA Study that the collective data reasonably demonstrates that a resource adequacy shortfall or reliability violation will occur during the timeframe of the study, Section 9.15(o) requires that the IPA, in conjunction with the IEPA, "shall develop a plan to reduce or delay CO_2e and copollutant emissions reductions requirements only to the extent and for the duration necessary to meet the resource adequacy and reliability needs of the State, including allowing any plants whose emission reduction deadline has been identified in the plan as creating a reliability concern to continue operating, including operating with reduced emissions or as emergency backup where appropriate. The plan shall also consider the use of renewable energy, energy storage, demand response, transmission development, or other strategies to resolve the identified resource adequacy shortfall or reliability violation."

As part of the mitigation plan development process, the IPA and the IEPA are required to hold at least one publicly accessible and convenient stakeholder workshop and consider stakeholder and public comments to inform the mitigation plan activities. After publication of the mitigation plan, the statute calls for a 60-day public comment period and encourages comments that are (i) "encouraged to be specific, supported by data or other detailed analyses" and (ii) "accompanied by specific alternate wording or proposals" if objecting to all or a portion of the plan. The IPA and the IEPA are allotted 30 days following the public comment period to revise the mitigation plan as necessary and file the plan with the ICC for approval. Following the filing of the mitigation plan, the ICC is required to host three public hearings and enter its order approving the plan with or without modifications within 180 days of any evidentiary or public hearings.

The ICC may only approve the mitigation plan if it determines that it will resolve the resource adequacy or reliability deficiencies identified in the mitigation plan with the least amount of emissions allowed and while ensuring adequate, reliable, affordable, efficient, and environmentally sustainable electric service at the lowest cost over time.[15] If the resource adequacy or reliability deficiency identified in the mitigation plan is resolved or reduced, the IPA and IEPA may collectively file an amended plan that adjusts the delay in emissions reductions requirements identified in the plan.

1.2. Context: The Electric System, Deregulation and Illinois

The electric power grid is comprised of three primary components: generation, transmission, and distribution. A generating unit is any combination of physically connected generators, reactors, boilers, combustion turbines, and devices or machines operated

[15] 415 ILCS 5/9.15(o)(3)–(4) (Illinois Environmental Protection Act)

together to produce electric power. Generating units can be fueled by fossil fuels (e.g., coal, petroleum, or natural gas), nuclear fission, running water, or renewable resources such as wind and solar. Transmission is inclusive of an interconnected group of high voltage lines and associated equipment for the movement or transfer and conditioning of electric energy between generating units and locations at which electricity is transformed for delivery to customers. Distribution is inclusive of the group of lower-voltage lines and associated equipment that deliver energy from the transmission system to retail customers.

In many jurisdictions across the country, electric utilities own and operate the full 'resource stack'—that is, the utility that transmits and distributes electricity to customers also own electric generating plants. These utilities and their electricity markets are defined as "vertically integrated." By contrast, the largest electric utilities in Illinois own and operate transmission and distribution networks but do not own or operate generation resources; these utilities are defined as "unbundled" utilities. Some electric utilities in Illinois, such as MidAmerican Energy Company (MidAmerican) are vertically integrated, and municipal (muni) and cooperative (co-op) utilities are structured differently than the larger utilities. Given the relative size of Illinois customers served by "unbundled" utilities, this report is largely focused on the specific resource adequacy constructs of that type of market.

Markets with this type of "unbundled" structure are referred to as restructured markets. In December 1997, the Illinois General Assembly enacted Illinois Public Act 90-0561, the Electric Service Customer Choice and Rate Relief Law of 1997, which restructured Illinois electricity markets and resulted in the transfer of electric generating plants, formerly owned by electric public utilities, to deregulated companies, i.e. companies not overseen by the ICC. This move was designed to provide consumers with greater choice and to allow consumers to "… benefit in an equitable and timely fashion from the lower costs for electricity that result from retail and wholesale competition."

Electric consumers in the Ameren Illinois (Ameren), Commonwealth Edison (ComEd), and MidAmerican service territories can choose who provides the supply of the generation portion of their electric service. For residential and small commercial retail electric customers, electric supply may be sold by either the utility (as default service supply, or real-time pricing which is a direct pass through of wholesale market prices) or an Alternative Retail Electric Supplier (ARES) —both of which operate as a Load Serving Entity (LSE) for their supply customers. Larger customers must either elect real-time pricing or take service from an ARES. ARES and electric utilities can purchase electricity from the MISO and PJM wholesale markets to sell to their customers,[16] or these load serving entities can also

[16] Ameren Illinois and MidAmerican purchase their electricity through MISO markets, ComEd purchases its electricity through PJM markets.

manage the cost of purchased electricity through contracts with electric generators or financial counterparties. The ICC generally does not have authority over the rates charged by ARES to their retail customers. For Illinois consumers who live within the regulated service territories of Ameren, ComEd, and MidAmerican and do not choose an ARES or real-time pricing, the Illinois Power Agency (IPA) facilitates the procurement of electricity supply on behalf of Illinois utilities through its annual Electricity Procurement Plan (EPP).

Independent System Operators (ISO) and Regional Transmission Organizations (RTOs) are independent and often overlapping entities that, among other things, manage the bulk power transmission systems within their footprints, ensure non-discriminatory access to the transmission grid by customers and suppliers, dispatch generation assets to balance supply and demand, and develop regional transmission expansion plans. Importantly, given Illinois' reliance on wholesale markets, ISOs and RTOs operate wholesale markets for electric energy, capacity, and ancillary services.

ISOs grew out of Federal Energy Regulatory Commission (FERC) Orders Nos. 888 and 889, where the FERC suggested the concept of an Independent System Operator to provide for non-discriminatory access to transmission. Later, FERC, through Order No. 2000, encouraged voluntary formation of Regional Transmission Organizations (RTOs), which are generally organizations formed from smaller transmission entities and/or ISOs. Hereafter, this report will refer to ISOs and RTOs collectively as RTOs for simplicity.

RTOs are overseen by FERC and are not regulated by the Illinois Commerce Commission or any state agencies. There are currently seven RTOs in the continental United States, as shown in Figure **1-1**.

Figure 1-1: RTOs across the US

Source: "An Introductory Guide to Electricity Markets Regulated by the Federal Energy Regulatory Commission", https://www.ferc.gov/introductory-guide-electricity-markets-regulated-federal-energy-regulatory-commission.

The Illinois Electric Service Customer Choice and Rate Relief Law of 1997 required that the electric public utilities operating transmission assets in Illinois become members of an RTO. Transmission networks in Illinois are owned primarily by ComEd in Chicago and Northern Illinois, Ameren in Central and Southern Illinois, and MidAmerican in the Quad Cities area of Illinois.

Ameren and MidAmerican Energy are members of the Midcontinent Independent System Operator (MISO). In 2001, the FERC approved MISO as the nation's first RTO. By 2002, the utility companies that ultimately became Ameren Illinois were members of MISO. MidAmerican joined MISO as a transmission-owning member in 2009. MISO is the electric grid operator for 15 states, the City of New Orleans, and the Canadian province of Manitoba. Ameren and MidAmerican give operating control over their transmission networks to the transmission system operator MISO. ComEd is a member of the PJM Interconnection (PJM). PJM was designated an RTO by FERC in 2001. In 2004, ComEd was integrated into PJM. PJM is an RTO that coordinates the movement of wholesale electricity in all or parts of 13 states and the District of Columbia. ComEd gives operating control of its transmission network to the transmission system operator PJM.

Interconnections of transmission exist not only within RTOs, but between RTOs (and other non-RTO entities) as well. Figure 1-2 shows the approximate geographic boundaries of the four synchronized alternating current electric systems recognized by the North American Electric Reliability Corporation (NERC): (1) the "Eastern Interconnection" (within which both MISO and PJM are situated); (2) the "Western Interconnection"; (3) the "ERCOT Interconnection" (Texas); and (4) the "Quebec Interconnection."

PJM and MISO, subject to the authority of the FERC, oversee their respective wholesale markets, which are relied upon by LSEs in Illinois that provide electricity to Illinois retail customers. Both PJM and MISO facilitate day-ahead and real-time energy markets.[17]

Through day-ahead markets, participating generators make financially binding commitments to supply energy on an hourly basis for the next day based upon expected load needs. MISO describes the day-ahead market as follows:

> The Day-Ahead Market serves as a "planning phase" for the next operating day. This market allows buyers and sellers to lock in pricing prior to real-time. This helps ensure that adequate resources are scheduled to meet the next day's anticipated demand.[18]

In real-time markets, resources are dispatched to meet system needs with any adjustments made to day-ahead load and generation needs. MISO describes the real-time market as follows:

> The Real-Time Energy Market balances energy supply with demand every five minutes at the least possible cost while maintaining reliable system conditions; including reserve requirements, congestion management and accurate price signals.[19]

For a generating resource to be accepted by the RTO and used in price formation, otherwise referred to as "clearing the market," supply offers are generally stacked from lowest to highest prices, and generators are selected in "merit order" from lowest to highest offers to meet demand at every time interval, further subject to other operational conditions of the resource and to identified transmission constraints.

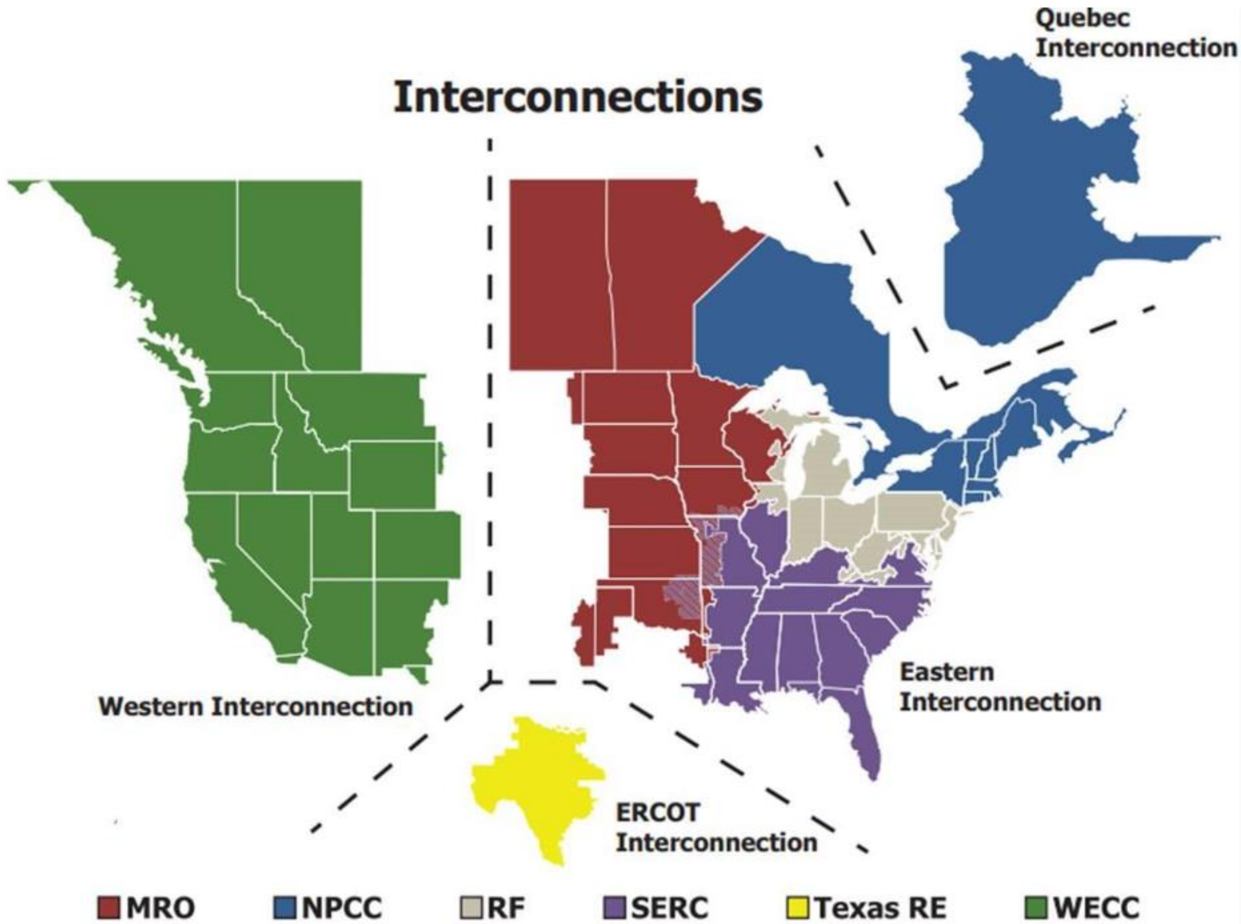
---

[17] PJM and MISO day-ahead and real-time markets are denominated in kilowatt hours (kWhs) or megawatt hours (MWhs).

[18] MISO Energy Markets 101: How Electricity is Bought and Sold: https://www.misoenergy.org/meet-miso/about-miso/industry-foundations/market-basics/

[19] MISO Markets and Market Participation Overview: https://cdn.misoenergy.org/Fact%20Sheet%20-%20MISO%20Market%20Participation%20Overview632546.pdf

Figure 1-2: Interconnection within the US



Source: NERC Interconnections, https://www.nerc.com/AboutNERC/keyplayers/PublishingImages/NERC%20Interconnections.pdf#search=interconnections.

Energy and capacity are related but distinct ideas. Energy is the commodity product that flows to customers at each moment to power their homes and businesses. Energy is typically referred to as kilowatt-hour (kWh) or megawatt-hour (MWh), denoting energy as a function of time. Capacity generally refers to the maximum amount of potential generation available in a given time period. Capacity is commonly denominated in megawatts (MW). Capacity is the key metric used to evaluate resource adequacy. Resource adequacy generally means there are adequate resources on the grid to ensure that the forecasted demand for electricity can be met during the relevant period at a given level of probability.

To ensure sufficient levels of capacity, PJM and MISO impose capacity obligations on LSEs. LSEs can meet resource adequacy obligations by securing capacity through direct ownership of generating resources, bilateral contracts with a generating resource owner, or participation in an RTO-facilitated capacity auction. Capacity resource owners that sell (and clear) in a capacity auction receive capacity payments in exchange for a commitment to be available during specified periods of need as defined by the RTOs through the defined auction rules, processes, and manuals. The cost of these capacity payments is passed on to the LSEs and then ultimately collected from retail customers, and is in addition to the cost of actual energy delivered.

As a result of Public Act 90-0561, the State of Illinois does not have the authority to regulate generation that is not operated by electric public utilities. Furthermore, Section 8-503 of the Illinois Public Utilities Act (PUA) states:

> … the Commission shall have no authority to order the construction, addition or extension of any electric generating plant unless the public utility requests a certificate for the construction of the plant pursuant to Section 8-406 and in conjunction with such request also requests the entry of an order under this Section.[20]

Illinois' resource adequacy ultimately depends on the performance of PJM and MISO, but the state retains important levers that shape generation outcomes. While FERC oversees the regulation of wholesale electricity markets, Illinois maintains authority over resource adequacy and administers electricity procurement plans that guide how supply is secured for select customers. In practice, Illinois has chosen to rely on regional market mechanisms to meet its RA requirements. This distinction between federal oversight of wholesale markets and state authority over procurement and resource adequacy, is central to understanding Illinois' role in supporting generation development and retention.

1.3. Roles of Illinois Agencies, Participating Parties, and Stakeholder Engagement

The Resource Adequacy Study was developed through a coordinated effort, with the Agencies bringing technical expertise and policy perspectives to ensure the design and execution of the study was responsive to the directive under Section 9.15(o) of the Illinois Environmental Protection Act. The Agencies also utilized the services of IPA's Procurement Planning Consultant, Energy and Environmental Economics, Inc. (E3), to conduct the analysis and support the overall process and development of the Resource Adequacy Study. The Agencies also permitted engagement with stakeholder groups, the RTOs, and Illinois utilities. The Agencies coordinated with PJM and MISO to verify modeling assumptions and seek guidance on available data resources and coordinated with the Illinois utilities to

[20] 220 ILCS 5/8-503.

inform the treatment of load forecasts and cross-reference approaches with other utility-driven studies. This collaborative structure ensured that the study was grounded in the best available data and reflected current market developments.

1.3.1. Illinois Power Agency

The Illinois Power Agency (IPA) is an independent state agency established under Illinois law in 2007 through the enactment of the Illinois Power Agency Act. Under the oversight of the Executive Ethics Commission, the IPA is committed to:

- Ensuring the process of power procurement is conducted in an ethical and transparent fashion, immune from improper influence.
- Conducting competitive procurement processes to procure the supply resources identified in procurement plans.
- Operating in a structurally insulated, independent, and transparent fashion so that nothing impedes its mission to secure power at the best prices the market will bear, provided it meets all applicable legal requirements.
- Continuing to review its policies and practices to determine how best to meet its mission of providing the lowest cost power to the greatest number of people, at any given point in time, in accordance with applicable law.

The IPA is charged with preparing annual electricity procurement plans[21] that define the methods and terms the IPA will implement to conduct procurement events to obtain supply on behalf of default service residential and small commercial customers of Illinois. The IPA conducts procurement events to obtain electric supply for Ameren, ComEd, and MidAmerican default service customers, and conducts capacity procurement events to obtain zonal resource credits (ZRCs) and/or financial ZRCs for Ameren default service customers. The IPA is also responsible for facilitating achievement of the Illinois Renewable Portfolio Standard (RPS), a public policy designed to drive the development of renewables in Illinois, and other vital energy policy initiatives. To support achievement of the RPS goals, the Agency develops and implements a biennial Long-Term Renewable Resources Procurement Plan (Long-Term Plan),[22] which defines a host of programs and procurement

[21] Illinois Power Agency Electricity Procurement Plan: https://ipa.illinois.gov/electricity-procurement/electricity-procurement-plan.html

[22] Illinois Power Agency Long-Term Renewable Resources Procurement Plan: https://ipa.illinois.gov/renewable-resources/long-term-plan.html

processes[23] to support the development renewable energy systems throughout the state and support achievement of the RPS and clean energy targets and goals. Both the electricity procurement plan and the Long-Term Plan are filed with and approved by the ICC before implementation. The IPA has also previously conducted procurements of Zero Emissions Credits and Carbon Mitigation Credits to help support at-risk nuclear plants.

1.3.2. Illinois Commerce Commission

The Illinois Commerce Commission (ICC or Commission) is a regulatory body, established by the Illinois Public Utilities Act.[24] The mission of the ICC is to balance interests of consumers and service providers and ensure adequate, efficient, reliable, safe, least-cost public utility services.

Under the Illinois Public Utilities Act, the ICC has authority to regulate the rates, terms and conditions of the distribution services provided by electric utilities.[25] There are four investor-owned electric utilities subject to the authority of the ICC: ComEd, Ameren, MidAmerican and Mt. Carmel. The ICC does not have authority over the rates, terms and conditions of the distribution services provided by municipal public utilities or electric cooperatives.

While the ICC has authority to regulate distribution services provided by electric utilities, the ICC has limited regulatory authority over transmission services. The Federal Energy Regulatory Commission (FERC) is an independent Federal agency with responsibilities that include regulation of transmission. While FERC generally regulates the rates, term, and conditions of transmission services, the ICC does have general authority over the siting of transmission lines in Illinois.

Working within its existing authority and current federal regulatory rules and constructs, the ICC monitors and participates in RTO and FERC matters and advocates for market rules and other measures that best enable Illinois to meet it resource adequacy needs. The ICC not only advocates individually on behalf of Illinois but works with other state public utility commissions and the regional state committees that among other things, coordinate state positions and responses on federal issues, both at the RTOs and FERC. The ICC is a member

[23] IPA programs are inclusive of the Illinois Shines Program (also referred to as the Adjustable Block Program) and Illinois Solar for All Program. IPA procurements include utility-scale renewable energy procurement events for wind and hydropower, solar, and brownfield photovoltaics. The Long-Term Plan also includes other programs and provisions such as the Self-direct Program, details surrounding RPS Budgeting, adjacent state project provisions, consumer protections, and diversity equity and inclusion.

[24] Illinois Pubic Utilities Act: https://www.ilga.gov/Legislation/ILCS/Articles?ActID=1277&ChapterID=23&Chapter=UTILITIES&MajorTopic=REGULATION

[25] Ibid., 220 ILCS 5/9-201

of the Organization of MISO States (OMS), the regional state committee in MISO. The ICC is also a member of the Organization of PJM States (OPSI), the regional state committee in PJM.

The ICC also has regulatory authority to oversee the administration of several electric utility programs that have a direct impact upon resource adequacy including, but not limited to, energy efficiency and demand response programs and net metering and distributed generation rebate programs that incent the deployment of distributed generation resources.[26] The ICC also, as more fully explained in this report, approves IPA procurement plans for, and resource selections with respect to, energy, capacity, and renewable resources procured by the IPA on behalf of retail electric customers.[27]

As the study exemplifies, the ICC, in coordination with the IPA and IEPA, also has the responsibility to monitor and assess resource adequacy in Illinois. This monitoring and assessment responsibility includes the ICC's work with respect to the Renewable Energy Access Plan (REAP), that includes identification of zones in Illinois that are suitable for renewable energy development and identification of investments needed to connect REAP zones with sufficient transmission capacity.

1.3.3. Illinois Environmental Protection Agency

The Illinois Environmental Protection Agency (IEPA) is an agency established under the Illinois Environmental Protection Act (EPAct) in 1970.[28] The mission of IEPA is to safeguard environmental quality, consistent with the social and economic needs of the State of Illinois, so as to protect health, welfare, property, and the quality of life.

Under the EPAct, IEPA is designated as the air pollution control agency for the State of Illinois for all purposes of federal acts, including the Clean Air Act. IEPA's Bureau of Air has primary responsibility for carrying out the State's obligations to ensure clean and safe air for Illinois' residents and the environment. Among other responsibilities, IEPA has the duty and authority to collect and disseminate information and technical data required to carry out the purposes of the EPAct. This includes:

- Ascertaining the quantity and nature of discharges from any contaminant source;
- Operating and coordinating the operation of devices to monitor and assess air quality through the Illinois Ambient Air Monitoring Network;

[26] 220 ILCS 5/8-503
[27] 220 ILCS 5/16-101A(e)
[28] 415 ILCS 5/4

- Collecting emissions data from regulated sources and developing emissions inventories and air quality attainment demonstrations;
- Administering permit programs for stationary sources of air pollution;
- Making recommendations to the Illinois Pollution Control Board for the adoption of regulations under Title VII of the EPAct; and
- Investigating possible violations of the EPAct and regulations adopted thereunder and taking appropriate enforcement action in response to violations.[29]

IEPA implements, maintains, and enforces State Implementation Plans for the National Ambient Air Quality Standards for criteria pollutants, which include carbon monoxide, lead, oxides of nitrogen, ozone, particulate matter, and sulfur dioxide. The IEPA also administers a federally required vehicle inspection and maintenance program.

Specific to its role under CEJA, IEPA oversees compliance with the decarbonization provisions of Section 9.15 of the EPAct that phase out emissions of electric generating units (EGUs) and large GHG-emitting units while prioritizing environmental justice and equity investment eligible communities. Section 9.15 establishes deadlines by which subject units must reduce GHG emissions by specified amounts, as well as deadlines by which subject units must reduce GHG and copollutant emissions to zero.[30] Certain units are also restricted from emitting GHGs and copollutants in amounts that exceed the unit's existing emissions.[31]

Section 9.15 allows units to temporarily continue operating after an applicable deadline if necessary to maintain power grid supply and reliability or to serve as an emergency backup to operations.[32] Since the passage of CEJA, Illinois EPA has been incorporating applicable requirements of the law into the operating permits of subject facilities in Illinois.

Under CEJA, IEPA is also required to annually report actual GHG emissions from individual units and the aggregate statewide emissions from all units for the prior year. IEPA began reporting historical emissions in June 2025 with its *Annual Greenhouse Gas Emissions Report for Sources Subject to the Illinois Climate and Equitable Jobs Act - 2024*.[33]

Finally, under CEJA IEPA is required to collaborate with other state agencies on this resource adequacy and reliability report under Section 9.15(o) of the EPAct. The IEPA is contributing

[29] Ibid.
[30] 415 ILCS 5/9.15(g) through (k)
[31] 415 ILCS 5/9.15(k-5)
[32] 415 ILCS 5/9.15(l)
[33] IEPA/BOA/IL-2025-001

necessary emissions data to determine the status of GHG and copollutant reductions, consulting with other state agencies on permanently reducing sources' emissions to zero, and working in partnership with the IPA on stakeholder comments, revisions, and filing of the mitigation plan with the ICC.

1.3.4. Energy and Environmental Economics, Inc.

E3 serves as the IPA's Procurement and Planning Consultant. In its role, E3 supported the Resource Adequacy Study by designing and implementing a modeling framework, developing scenarios, collaborating with the Agencies, coordinating with the RTOs and Illinois utilities to align on data input assumptions and approach, helping facilitate the stakeholder engagement process, conducting the analysis, and drafting sections of the report and key findings.

1.3.5. Stakeholder Engagement

Stakeholder engagement through the RA Study included gathering data and input from markets and system contributors such as PJM, MISO, and the Illinois utilities and included stakeholder workshops and requests for written feedback. Direct outreach to the RTOs and utilities was critical to obtaining necessary data and forecast assumptions used in RA Study modeling and analysis. The broader stakeholder workshops and requests for feedback served to both inform stakeholders of the process and approaches to be used during the study (e.g., key inputs, base case assumptions, scenario design) and to solicit input and feedback from stakeholders to inform the study.

Section 9.15(o) requires the Agencies consult with PJM and MISO, "regarding forecasted resource adequacy and reliability needs, anticipated new generation interconnection, new transmission development or upgrades, and any announced large GHG-emitting unit closure dates and include this information in the report." Due to the critical importance of this report on shaping Illinois energy policy, the Agencies determined it was paramount to implement a report development process that would engage a wider set of stakeholders through workshops and the solicitation of written feedback.

During the development of the RA Study, the Agencies conducted workshops and received written comments from stakeholders. The workshops focused on providing stakeholders with foundational information on the RA Study process and approach, scenario design, data input, and summarized preliminary results. The Agency-issued stakeholder questions sought feedback to inform the prospective modeling and analysis design, data being used, scenario focus, and related considerations. While not every opinion or recommendation provided by stakeholders could be accommodated in the Report, the Agencies appreciate the time and effort stakeholders made to provide input into this complex process.

To provide a centralized location for stakeholders to access RA Study-related information, the IPA established a webpage.[34] The webpage contains two key sections, a matrix of "workshop information" and a summary timeline for stakeholder to reference throughout the process. The workshop information section provides links to all published materials, including announcements, agendas, workshop materials (presentations and recordings), and both written stakeholder questions and their responses. It was also important for stakeholders to be notified of important updates, which lead to the creation of an RA Study distribution list, whereby stakeholders could receive alerts notifying them of important updates, comment opportunities, and scheduled events. The Agencies held the first stakeholder workshop on June 16, 2025. The workshop focused on providing stakeholders with insights into the process the Agencies would employ to conduct the study.[35] This included providing:

- The statutory requirements directing the Resource Adequacy Study process, deliverables, and timing; and,
- The end-to-end project schedule including those items that are statutorily required and those sub-tasks that are embedded as components of the study process.

Further, the workshop defined the key elements of the RA Study as a means to solidify the focus and objectives, approaches, and other considerations important for stakeholders to understand. This included:

- A foundational understanding of resource adequacy studies;
- The methodological approach utilized;
- The underlying analytical framework;
- An introduction to the core topics including policy drivers and conditions;
- The concept design underpinning scenario development; and
- The roles of the Agencies and activities each are responsible for.

On June 18, 2025, following the workshop, the Agencies released a set of twelve questions across two topic areas.[36] The Agencies specifically sought stakeholder feedback on the (1)

---

[34] 2025 Resource Adequacy Study: ipa.illinois.gov/electricity-procurement/resource-adequacy.html
[35] 2025 Resource Adequacy Study, Workshop 1: https://ipa.illinois.gov/content/dam/soi/en/web/ipa/documents/20250616-presentation-ra-study-workshop1-final-16june2025.pdf
[36] 2025 Resource Adequacy Study Post-Workshop Stakeholder Questions: 202506180-stakeholder-questions_ra-study-final_17june2025.pdf

Resource Adequacy Study goals and scenario analysis to provide recommendations to inform the (2) analytical approach and data assumptions. Responses were due on July 16. Twenty-one stakeholders ultimately submitted comments and recommendations.[37]

In parallel with the issuance and review of stakeholder comments to the first workshop's stakeholder questions, the Agencies also conducted outreach to MISO and PJM, seeking additional strategic insights and information into each RTO's own resource adequacy analyses, requesting data to inform modeling, and requesting any additional data or information that may be valuable to the Illinois RA Study process. The Agencies and E3 met with the RTOs on July 15, 2025, to discuss the information the team sought from the RTOs and had subsequent follow-up correspondence to get information from relevant data sources, documents, or reports.

On October 8, 2025, the Agencies held a second workshop.[38] This workshop sought to provide stakeholders with information on scenario design, a summary of inputs and assumptions informing modeling, to present preliminary analysis and results from modeling, and to provide initial technical findings. During the workshop, stakeholders asked the Agencies questions, seeking clarification on data inputs, model assumptions, scenario design, and modeling tool functionality. In response, the Agencies issued written responses to those questions.[39] Similar to the previous workshop in June, the Agencies issued a series of questions, seeking written stakeholder feedback—the result of which would help inform final modeling sensitivities and provide considerations for further future analysis, either as part of this RA Study process or a future one.[40] The questions to stakeholders consisted of five multi-part prompts covering key themes including: (1) requests for additional detail or clarification on the modeling approach and assumptions beyond what was asked during the workshop; (2) follow-up questions based on prior agency responses to stakeholder feedback during the workshop; (3) perspectives on the most important considerations for resource adequacy between now and 2030 and for the 2030 to 2035 period; (4) how out-of-state power plant retirements should be handled in the analysis; and (5) identification of any

---

Responses to Post-Workshop Stakeholder Feedback Request for Resource Adequacy Study: https://ipa.illinois.gov/electricity-procurement/resource-adequacy/responses-to-post-workshop-stakeholder-feedback-request-for-reso.html

[38] 2025 Resource Adequacy Study Resource Adequacy Workshop 2: https://ipa.illinois.gov/content/dam/soi/en/web/ipa/documents/20251008-presentation-ra-study-workshop-2-combinedfinal-8oct2025.pdf

[39] 2025 Resource Adequacy Study Workshop #2 Responses to Stakeholder Questions: https://ipa.illinois.gov/content/dam/soi/en/web/ipa/documents/rastudy-stakeholderworkshop2-qa-10oct2025.pdf

[40] 2025 Illinois Resource Adequacy Study: Post-Workshop #2 Stakeholder Questions: https://ipa.illinois.gov/content/dam/soi/en/web/ipa/documents/20251016-stakeholder-questions_ra-study-final-16oct2025.pdf

outstanding stakeholder questions not yet addressed. Responses were due on October 28, 2025, with eight stakeholders submitting comments.[41] Refer to Appendix A for a summary of stakeholder comments received.

1.3.6. Stakeholder Considerations

Stakeholder engagement across both workshops provided broad, detailed input that directly informed scenario design, key modeling assumptions, and data sources used in this RA Study. Participants emphasized that reliability, affordability, and the pace of decarbonization should anchor the Study's analytical framework, with many highlighting the impacts of load growth, resource retirements, emerging technologies, and evolving RTO market rules. Stakeholders also underscored the importance of incorporating recent MISO and PJM market developments, including accreditation reforms, interconnection queue outcomes, and regional resource trends. Stakeholder comments also recommended that scenarios reflect a range of potential futures, from pessimistic to optimistic cases. Additional drivers identified by stakeholders, such as extreme weather, demand response potential, data center growth, and the availability of natural gas during winter peaks, reinforced the need for diverse and stress-tested modeling scenarios.

Feedback also provided actionable guidance on data inputs. Stakeholders recommended aligning RA Study datasets with publicly available RTO planning assessments, generator retirement notices, and interconnection queue data; leveraging state-specific resources such as the REAP; and incorporating third-party research from NREL, EPRI, Lazard, and other national studies. Several stakeholders requested explicit treatment of behind-the-meter resources, distributed generation, the role of energy storage, and the implications of CEJA-driven retirements, while others pointed to transmission constraints and expansion plans in PJM and MISO as critical factors shaping reliability outcomes.

Across both workshops, participants stressed that affordability, reliability, and system flexibility remain the core challenges for Illinois through 2035, and that the Study should explicitly examine how federal and state policies, interregional retirements, and evolving market designs may shift future reliability conditions. Collectively, this input helped refine the Study's scenario design, ensured the use of current and credible data, and highlighted the need for continued engagement and re-evaluation as market, policy, and technological conditions evolve.

---

[41] Responses to Second Post-Workshop Stakeholder Feedback Request for Resource Adequacy Study: https://ipa.illinois.gov/electricity-procurement/resource-adequacy/responses-to-second-post-workshop-stakeholder-feedback-request-f.html.

1.4. The Scope and Focus of the RA Study

1.4.1. Overview of Contents

This document, and its corresponding analysis and modeling, was prepared to meet the requirements of Section 9.15(o) of the EPAct. Through Section 9.15(o), the Agencies are tasked with jointly evaluating the current and projected status of electric resource adequacy and reliability in Illinois. The contents of this report are organized to provide both a technical and policy-grounded response to that directive, covering the near- and long-term outlook for the state's electric grid as it transitions under the requirements of the CEJA.

This study utilizes a three-part modeling framework to assess current and projected resource adequacy risks in Illinois. This approach is designed to capture both near-term system needs and long-term planning considerations under CEJA, using scenario-based analysis to evaluate outcomes under a range of assumptions related to load growth, fossil retirements, renewable deployment, and policy implementation.

Following introductory material provided in Chapter 1, the report then defines the scope of this RA Study in Chapter 2 including the definitions of resource adequacy concepts and metrics, explaining the role of RTOs, and contextualizing Illinois' electric system within the broader electricity markets. Chapter 2 also introduces emerging trends and risk factors, such as load growth, clean resource integration, and fossil generation retirements, which influence the resource adequacy outlook.

Chapter 3 transitions from resource adequacy fundamentals to policy context, expounding on the clean energy and emissions reduction goals established under CEJA. The chapter outlines key statutory targets, the mechanisms used to achieve and enforce those targets, progress towards meeting the CEJA targets, and how these policy developments intersect with reliability concerns, particularly as certain fossil generating units face restrictions or retirement timelines.

Chapter 4 provides a near-term outlook using a resource adequacy balance model, a tool that projects future capacity needs as compared to available supply. It evaluates the anticipated evolution of supply and demand over the next five years, tracking projected retirements, new resource additions, and load growth at the state and regional level. The chapter also summarizes current capacity market dynamics in MISO and PJM and their implications for Illinois.

To further evaluate these near-term findings, Chapter 5 presents a longer-term analysis of resource adequacy needs and challenges. Using capacity expansion modeling and loss-of-load probability modeling, this chapter explores future reliability risks and investment needs in and beyond 2030, assessing how system requirements could evolve under different scenarios.

Chapter 6 discusses the potential cost implications of the evolving resource adequacy needs in Illinois and the broader RTO markets for Illinois electricity consumers.

The report concludes with Chapter 7 that brings together the report's analytical findings to present Illinois' overall reliability outlook and the key drivers shaping future resource adequacy. It summarizes how state policies, regional RTO conditions, and projected supply–demand trends interact to create the risks and opportunities identified throughout the study. The chapter then outlines the statutory next steps required under Section 9.15(o), including when a Mitigation Plan must be developed and how it will be reviewed by the Illinois Commerce Commission. It concludes by explaining how these requirements align with the new Integrated Resource Planning framework under CRGA, ensuring that the study's results inform the State's broader long-term planning process.

1.4.2. Next Steps and The Illinois Energy Planning Ecosystem

The RA Study and its findings conclude the first phase of a prospective two-part process. The RA Study establishes a finding that during the period studied, the analyses conducted herein, "reasonably demonstrate that a resource adequacy shortfall will occur, including whether there will be sufficient in-state capacity to meet the zonal requirements of MISO Zone 4 or the PJM ComEd Zone, per the requirements of the regional transmission organizations, or that the regional transmission operators determine that a reliability violation will occur."[42] Given that finding, the IPA and the IEPA are to "develop a plan to reduce or delay CO2e and copollutant emissions reductions requirements only to the extent and for the duration necessary to meet the resource adequacy and reliability needs of the State,"[43] with that Plan (Mitigation Plan) to be filed with and litigated before the ICC.

Section 9.15(o) requires that the IPA and IEPA hold at least one workshop during the development of the Mitigation Plan and that the IPA and IEPA release a draft plan and take comments on that draft plan prior to filing the Plan for approval with the ICC. Once filed with the ICC, stakeholders will also have the opportunity to submit objections to the Plan during a contested proceeding. The RA Study and the subsequent Mitigation Plan mandated by Section 9.15(o) do not exist in a vacuum. There are a number of additional processes that will inform decisions related to generation, transmission, and energy efficiency investments which have the potential to impact resource adequacy in Illinois.

---

[42] 415 ILCS 5/9.15(o)
[43] Ibid.

Section 9.15(o) also dovetails with broader planning reforms recently adopted by the General Assembly. In October 2025, lawmakers passed Senate Bill 25, the Clean and Reliable Grid Affordability Act (CRGA), which establishes a formal Integrated Resource Planning (IRP) framework for Illinois once signed into law. The IRP process, expected to take place throughout 2026 and 2027, is intended to provide a more comprehensive venue for addressing many of the foundational issues identified through the RA Study within a unified, multi-year planning framework. As a result, the RA Study should be viewed as both an input to, and an early bridge toward, the prospective IRP process. Both the RA Study and Mitigation Plan focus on the identification of key resource adequacy challenges and prospective solutions to those challenges, which can be evaluated in greater depth through IRP proceedings.

These planning reforms do not occur in isolation. The State's resource adequacy, clean energy, and transmission objectives are shaped by a set of ongoing analytical processes that together inform long-term decision-making. As shown in Figure 1-3, Illinois has a number of interrelated studies that help to guide Illinois energy policy and actions. These studies rely on a common set of assumptions and inputs and work towards a set of actions that in turn update the common assumptions.

Figure 1-3: Ecosystem of Illinois State Energy Planning

Illinois' energy planning landscape operates as an interconnected cycle, with shared inputs informing agency studies and plans that, in turn, drive regulatory, procurement, and transmission actions. Each of these processes includes opportunities for stakeholders to provide input and shape the outcomes. By outlining this interconnected framework, this chapter has set the stage for understanding how the analyses in subsequent chapters fit into the State's evolving, data-driven planning environment.

2. Context: Resource Adequacy in Illinois

2.1. Defining Resource Adequacy

2.1.1. Resource Adequacy Key Concepts

Resource Adequacy (RA) evaluates whether there is sufficient electricity supply available to meet corresponding customer demand in all hours within a defined level of certainty. This is a critical concept for electricity system planning, which evaluates how future resource portfolios meet policy, affordability, and reliability objectives. No electric system is "perfectly reliable"—meaning that there is a zero percent chance of a loss of load event. Electric systems are instead designed to achieve a specific reliability standard which represents an acceptable probability of lost load over a range of possible conditions while balancing the feasibility and costs of meeting this target with available technologies.

The resource adequacy of Illinois is inherently tied to the resource adequacy of the RTO the Illinois territory is in, i.e., Ameren's resource adequacy is heavily determined by MISO's resource adequacy and ComEd's is heavily determined by PJM's resource adequacy. Electric suppliers in Illinois are responsible for procuring capacity to meet their share of each RTO's reliability requirements. The cost of resource adequacy for Illinois customers is primarily determined according to the centralized capacity market auctions held by MISO and PJM.

Throughout the RA Study, resource adequacy is primarily assessed in terms of the installed and accredited capacity of generators (in megawatts, or MW), relative to projected peak demand plus reserve margin requirement established by each RTO, including limits in Illinois-specific zones based on transfer capacity. This study evaluates the ability to maintain the planning reliability standards over time, rather than real-time operational reliability or local transmission constraints. These other forms of reliability studies, while important to the operation of the grid, are not the focus of this study. This study assesses resource adequacy with tools that simulate long-term supply-demand balances, probabilistic risk of shortfall, and scenario-based outcomes under different policy and market conditions.

Reliable electric service is critical to the safety, convenience, comfort, and health of residential customers, and to the economics and safety of businesses. Unreliable service can cause loss of electric services, such as brownouts or blackouts, uncertainty, price volatility, and economic damages of varying scales. While service outages on the distribution system are the most common reliability effect experienced by customers, outages of the generation system, while rare, are major events that should be avoided when possible.

2.1.2. Evolution of Resource Adequacy

Traditionally, utilities ensured resource adequacy through meeting the minimum planning reserve margin (PRM) based on the installed capacity of generation resources, the risk of sudden generator outages, and the expected peak load of the system. This approach guided system reliability planning for decades, and it assumed all generation resources could produce at full capacity whenever needed, with allowances for unplanned ("forced") outages. This reliability planning paradigm no longer holds true with the introduction of variable and intermittent renewable resources and battery storage added to the grid at scale. Therefore, comparing installed nameplate capacity against peak load alone is no longer sufficient to ensure adequacy.

Modern RA approaches adopt probabilistic methods that combine three components (1) development of a loss-of-load-probability (LOLP) model to simulate hourly system conditions across many weather scenarios; (2) derivation of the total "perfect capacity" required to meet an accepted reliability standard; and (3) application of effective load-carrying capability (ELCC) to quantify each resource's contribution to that reliability requirement. These methods attempt to better capture the stochastic nature of modern systems with diverse generation portfolios.

Determining the appropriate Planning Reserve Margin (PRM) in today's complex electric system requires consideration of several key metrics. These metrics, defined below, are defined broadly to orient the report towards these concepts. In practice, each RTO has specific methods and terminology that differ from the generic descriptions listed here. Later in the chapter is a discussion of how each RTO determines resource adequacy.

Planning Reserve Margin (PRM). The PRM is defined as the minimum quantity of reliable generation capacity installed that is needed to maintain grid reliability within specified loss of load parameters. The PRM value is generally set above the expected electricity demand, specified in percent of the peak load requirement. This additional capacity requirement attempts to assure reliable electric generation service over time considering limited cases of generator outages or higher levels of demand than forecasted. The reserve capacity may be owned directly or secured through bilateral transactions or market purchases, including from neighboring zones if the capacity is deemed deliverable under applicable market rules. A PRM is often used by regional markets to define the minimum or benchmark amount of generation that needs to be installed to support acceptable reliability in that region.

Effective Load Carrying Capability (ELCC). ELCC helps inform the PRM, thus generators must demonstrate an ability to contribute capacity during times of system need. This requirement led to the development of *ELCC*, which measures the portion of a resource's capacity that can be counted toward reliability standards. For traditional, fully dispatchable resources such as nuclear, coal, or gas-fired units, ELCC reflects adjustments to nameplate capacity to account for *forced outage rates*—the percentage of time these units may be unavailable due to equipment failure—as well as fuel supply disruptions and changes in output based on temperature. For variable renewable resources such as wind and solar, ELCC represents the fraction of their installed capacity that is statistically expected to be available during periods of reliability need, considering the variability of weather and generation patterns. In other words, ELCC quantifies the dependable contribution that resources can make to meeting peak demand and maintaining reliability within the system. Capacity values that reflect ELCC will always be lower than the installed or nameplate capacity of a generation source. However, ELCC values are highly sensitive to the underlying data and assumptions, meaning that unusual historical conditions or atypical performance years can materially influence results.

Loss of Load Expectation (LOLE). Utility planners use the *LOLE* metric to evaluate how different levels of PRM affect system reliability within a region. LOLE analysis assesses the balance between customer load and available generation capacity, expressed as the ratio of load to ELCC.

Loss of Load Probability (LOLP). LOLP measures the likelihood that available generation will be insufficient to meet demand during peak periods. Summing the LOLP values across all days in a study period yields the LOLE value, which reflects the expected frequency (often expressed in days per year) that the system may experience a capacity shortfall.

Expected Unserved Energy (EUE). Utility planning studies using LOLE or generation production (fuel) cost modeling often determine a quantity called EUE. This is the probable amount of energy that is not provided to customers (called "Unserved Energy") in the event of a generation related system shortfall. Because the cost to customers of Unserved Energy (e.g., loss of electrical power to hospital surgical suites, loss of product in manufacturing processes, loss of comfort in home heating and cooling, etc.) is much higher than the cost of delivered electricity, utility planners design and operate the system to minimize the likelihood of unserved energy events.

Demand Curve. Demand curves play a central role in resource adequacy design by linking prices to system needs, helping determine how much capacity is procured and at what cost, and ensuring reliability is maintained cost-effectively. Well-designed, sloped demand curves provide clear price signals that rise gradually as capacity tightens, encouraging efficient investment, delaying premature retirements, and supporting demand response when supply is scarce. By reflecting consumers' value of reliability, including thresholds such as LOLE, these curves help balance long-term adequacy needs while avoiding unnecessary over-procurement.

These measures interact with one another such that, for example, increasing the required PRM should decrease the EUE. However, there are practical limitations. Increasing PRM requirements may reduce EUE but increase the quantity, and thus cost, of the generation capacity needing to be available on the system. Planners seek an optimal cost point where there is sufficient generation to hold EUE at an acceptably low level while minimizing total costs to customers.

2.1.3. How Resource Adequacy Is Determined

Achieving the appropriate level of resource adequacy for a region is done in the regular utility planning process, at the RTO level, or in combination of the two. Illinois has traditionally relied on PJM and MISO to determine RA needs because, as a restructured state, it elected not to administer its own centralized RA program and instead allowed regional markets to conduct planning, accreditation, and procurement. With the new IRP provisions contained in recently passed omnibus energy legislation, Illinois could re-examine this allocation of authority, creating opportunities for the State to take a more active role in shaping future RA requirements and resource portfolios. In general, the current process includes the following steps in Table 2-1.

Table 2-1: Process for Determining Resource Adequacy

Step	Process
1. Determine Total Reliability Need (TRN)	Prepare LOLE model for the existing portfolio and tune to LOLE standard using perfect capacity. The resulting perfect capacity (MW) is the Total Reliability Need (TRN).
2. Calculate PRM	Calculate the PRM from the TRN. $$PRM = \frac{TRN}{Median\ Peak\ Load} - 1$$
3. Calculate Resource Marginal ELCC Values	Marginal ELCC values are calculated based on the change in Portfolio ELCC with a change in the quantity of a given resource type. Portfolio ELCC measures the ability of the portfolio to fulfill the total reliability need, or its

	ability to offset the amount of perfect capacity needed to achieve reliability. Marginal ELCC measures a resource's performance during critical periods, when any additional capacity of the resource results in improved reliability.
4. Calculate Total Procurement Need	Total procurement need is the sum of the individual resources' accredited marginal ELCCs values.

Source: Energy and Environmental Economics (E3). "Resource Adequacy for the Energy Transition: A Critical Periods Reliability Framework and its Applications in Planning and Markets," Energy and Environmental Economics (E3), Inc., August 2025, https://www.ethree.com/wp-content/uploads/2025/08/E3_Critical-Periods-Reliability-Framework_White-Paper.pdf.

2.1.4. Shift from Peak Hours to Critical Periods for Resource Adequacy

Traditional resource adequacy standards have relied on setting PRMs based on peak annual demand periods, with a system considered adequate if it meets a LOLE of no more than 0.1 days per year (i.e., one day in ten years). This approach was developed when reliability risks were largely concentrated during severe hot or cold weather events that cause the highest demand and supply consisted primarily of firm, dispatchable generation. However, with higher penetrations of variable and energy-limited resources, low electricity supply conditions will be increasingly important drivers of critical periods. This shift has prompted a transition toward probabilistic and scenario-based planning frameworks that assess reliability under a wider range of system conditions, specifically "critical periods" in which power systems are most likely to suffer from supply shortfalls.

Shifting from traditional seasonal peak demand periods to a "critical periods" reliability framework incentivizes economically efficient investments that will meet changing supply and demand drivers. In MISO and PJM, the RTOs covering Illinois, resources are now being evaluated based on the marginal impact of their performance on system reliability during critical periods. This new "critical periods" framework identifies reliability-driven generation from a portfolio of resources and compensates new investments in these resources or voluntary load reductions that directly reduce the probability of lost load.[44]

[44] Ibid.

2.2. Role of Regional Capacity Markets in Ensuring Resource Adequacy

2.2.1. Roles of Regional Transmission Operators

An RTO plays a central role in ensuring the reliable and efficient operation of the electric grid across a large geographic area. RTOs are responsible for facilitating energy and capacity markets to match electricity supply with demand, ensure future resource adequacy needs are met, plan and manage wholesale transmission and interconnection, and monitor markets. These functions provide benefits to all customers, including lower costs of generation, improved reliability, increased access to diverse energy resources including renewable resources, increased transparent pricing and planning, and more efficient use of transmission infrastructure.

2.2.1.1. Energy Market Facilitation

RTOs operate day-ahead and real-time energy markets to match electricity supply with demand. The Day-Ahead Market (DAM) is used to match supply with forecasted demand one day in advance. Participants submit bids to buy or sell electricity for each hour of the next day, and the RTO clears the market by selecting the lowest-cost mix of generation to meet forecasted demand. This market helps ensure reliability and has clear price transparency.

The Real-Time Market (RTM) is used to adjust for differences between the day-ahead forecasts and actual conditions. The RTO operates this market to dispatch resources every five minutes to balance supply and demand in real time.

Locational Marginal Pricing (LMP) is a result of the energy markets and refers to the cost of delivering electricity at specific locations. LMP may differ between locations due to transmission congestion and losses between regions.

2.2.1.2. Capacity Market Facilitation

Capacity markets are intended to send price signals to market participants on the state of resource availability to meet future demand. High prices reflect constraints and the need to add supply, while lower prices indicate resource availability to meet forecast needs. In effect, capacity markets attempt to facilitate the availability of enough resources to meet likely future demands amidst market constraints. RTOs conduct resource adequacy planning to forecast future electricity needs and determine how much capacity will be required. They set rules for how much capacity each Load Serving Entity (LSE) must procure.

While MISO and PJM implement different market structures and design details, their capacity markets are conceptually aligned in purpose: both aim to ensure sufficient accredited resources are committed to meet reliability needs at least cost. Each uses forward procurement, accreditation methodologies such as ELCC or SAC, and market-based price formation tied to the cost of new entry to signal when new supply is needed. The differences between PJM's three-year forward BRA and MISO's annual PRA, or MISO's evolving seasonal accreditation framework, reflect regional policy choices and system characteristics, but the core objective remains the same: provide transparent, long-term signals that support resource adequacy.

Based on these capacity requirements, RTOs implement capacity auctions to facilitate a process to ensure LSEs meet their capacity procurement requirements. Capacity auctions are central to how RTOs safeguard that enough resources are committed to being available when needed, especially in restructured markets like Illinois. MISO's capacity auction is called the Planning Resource Auction (PRA), and PJM's is called the Base Residual Auction (BRA). In capacity auctions, generators offer capacity (MW), and LSEs bid for the capacity they need to meet their obligations. The auction clears at a market price, and winning resources commit to being available during peak demand.

RTOs also facilitate the accreditation and testing of capacity resources by assessing the reliability of each resource (e.g., thermal, wind, solar) and assigning Seasonal Accredited Capacity (SAC), the ELCC, or similar metrics. RTOs evaluate and assign a capacity value to each resource based on its expected performance. These metrics attempt to ensure that only reliable and proven capacity counts toward meeting resource adequacy.

RTOs use a combination of market mechanisms, planning processes, and technical evaluations to confirm resource adequacy and reliability is maintained. The goal of resource adequacy planning is to prevent the need for load shedding by ensuring sufficient capacity is available when needed, and the RTOs achieve this goal by assessing future demand and requiring LSEs to procure enough capacity. RTOs utilize tools including seasonal assessments, accreditation of resources, and reliability modeling to achieve this goal.

Capacity prices are the result of market mechanisms designed to meet resource adequacy requirements. Their goal is to provide a financial incentive for resources to be available during critical periods. RTOs run capacity auctions (e.g., MISO's PRA or PJM's BRA) and determine the prices by balancing the supply and demand for capacity, which is influenced by factors like resource mix, transmission constraints, load forecasting, and policy. In both regions, the critical periods for capacity needs are changing from a single period, typically a summer afternoon, and towards multi-season and multi-hour critical periods. Among other factors, this change in critical periods impacts can affect capacity prices, which are intended to reflect the value of reliability and help signal investment in new or retained generation.

Both markets utilize the cost of new entry (CONE), the projected costs of a generic new unit, as a guidepost for the market price when resource margins are tight or deficient. Since capacity is supposed to represent the "missing money" to secure investment in new (and existing) resources to provide resource adequacy, the logic is that the price cannot be higher than the cost of a new generating unit that is well-suited to provide capacity. As a first approximation, it follows that when an RTO faces tight capacity supply conditions (i.e., just enough resources to meet peak demand and reserve margin), the capacity price will rise to be CONE or net CONE after other revenues from wholesale markets (energy and ancillary services) are credited out. This price incentive is designed to serve two related goals: to provide a revenue incentive for new resources to enter the market to meet demand and to provide a cost incentive for loads to reduce demand during critical periods or contract with new resources to avoid paying the capacity market price.

2.2.1.3. PJM Capacity Market

The PJM capacity market, formally known as the Reliability Pricing Model (RPM), is designed to ensure long-term grid reliability by securing sufficient power supply resources to meet projected future electricity demand. The market ensures that utilities and suppliers have enough capacity to meet customer demand plus reserves, especially during peak periods and emergencies.[45]

Each PJM member (Load-Serving Entity or LSE) that provides electricity to consumers must acquire enough power supply resources to meet demand not only for today and tomorrow but for the future, generally planned 3 years ahead. Members secure these resources for the future through the PJM capacity market.

Under the "pay-for-performance" model, resources must deliver on demand during system emergencies or owe a significant payment for non-performance. This is meant to act like an insurance policy—for an additional cost (payment to resources which perform well), consumers have greater protection from power interruptions and price spikes during weather extremes. By matching power supply with future demand, PJM's capacity market attempts to create long-term price signals to attract needed investments to ensure adequate power supplies.

PJM's RPM follows a structured, multi-year timeline designed to ensure resource adequacy three years in advance of each delivery year. The auctions include the BRA and Incremental Auctions (IA).

---

[45] PJM Learning Center, "Capacity Market (RPM)", https://learn.pjm.com/three-priorities/buying-and-selling-energy/capacity-markets.aspx

The BRA is held three years prior to the delivery year (e.g., the BRA for the 2027/2028 Delivery Year is scheduled for December 2025).[46] The BRA is designed to secure the bulk of capacity needed to meet forecasted reliability requirements calculated based on projected loads and a target planning reserve margin designed to meet the RTO's 1-in-10 loss of load expectation standard. Participants in the BRA include generators and demand response providers.

IAs are held three times before the delivery year to adjust commitments made in the BRA based on updated forecasts or changes in resource availability. The first IA is held approximately 20 months before the delivery year (typically September), the second IA is held approximately 10 months before the delivery year (typically July), and the third IA is held approximately 3 months before the delivery year (typically February).[47]

PJM publishes a detailed timeline of activities leading up to the BRA, including a notice of Intent to Offer (approximately 180 days before), Minimum Offer Price Rule (MOPR) exemption requests (approximately 120 days before), Market Seller Offer Cap notifications (approximately 90 days before). The final planning parameters and accredited unforced capacity (UCAP) factors are released approximately five months before the delivery year.[48] These steps ensure transparency and compliance with market rules.

PJM is working to resume its three-year-forward planning cycle after many recent adjustments due to regulatory and market design changes. This cycle is meant to provide long-term investment signals and helps maintain reliability across its 13-state and District of Columbia footprint.[49]

2.2.1.3.1. Zonal Definitions: Locational Deliverability Areas (LDAs)

PJM divides its footprint into Locational Deliverability Areas (LDAs) to reflect transmission constraints and local reliability needs. LDAs are sub-regions within PJM where capacity must be procured separately due to limited import capability or historical reliability concerns. The ComEd service territory is the sole LDA in Illinois.

---

[46] PJM Press release, "PJM Auction Procures 134,311 MW of Generation Resources; Supply Responds to Price Signals", July 22, 2025, pgmnews@pjm.com
[47] PJM Manual 18: "PJM Capacity Market", Revision: 61, July 23, 2025, Section 5.2 RPM Auction Timeline, https://www.pjm.com/-/media/DotCom/documents/manuals/m18.pdf
[48] Ibid.
[49] PJM Press Release

LDAs are modeled in the auction if: 1) their Capacity Emergency Transfer Object (CETO)/Capacity Emergency Transfer Limit (CETL) margin[50] is less than 115%, meaning their import limits from other zones are less than their needs, 2) they had a Locational Price Adder in any of the last three BRAs, or 3) PJM determines they are likely to need a price adder based on historical data or reliability needs.[51] Each LDA also has import limits and constraints including a target capacity reserve level and a maximum import limit from external resources. These constraints ensure that local reliability is maintained even if transmission is limited.

2.2.1.3.2. Auction Clearing Process

The RPM uses the BRA and Incremental Auctions to procure capacity. PJM clears capacity offers to meet the administratively created demand curve or Variable Resource Requirement (VRR) Curve for each LDA and the larger RTO. If constraints require out-of-merit selection (i.e., higher-cost resources), clearing prices reflect those costs. Locational Price Adders are applied when LDAs are constrained, resulting in higher prices than the rest of the RTO.[52]

For the 2026/2027 and 2027/2028 BRAs, PJM applied or will apply a cap and floor to the VRR Curve (e.g., $329.17 cap and $177.24 floor for the 2026/2027 BRA). Offers above the cap are not cleared, while offers below the floor are cleared.[53] Clearing prices vary by LDA depending on constraints. Mitigation limits offer prices to the lesser of the Market Seller Offer Cap (MSOC) or the submitted price. For example, in the 2026/2027 BRA, all LDAs cleared at the cap price of $329.17/MW-day UCAP.[54]

2.2.1.4. Cycle and Timing of PJM Capacity Auctions

PJM's RPM follows a structured, multi-year timeline designed to ensure resource adequacy three years in advance of each delivery year. The auctions include the BRA and Incremental Auctions (IA).

The BRA is held three years prior to the delivery year (e.g., the BRA for the 2027/2028 Delivery Year is scheduled for December 2025).[45] The BRA is designed to secure the bulk of capacity

---

[50] PJM Capacity Emergency Transfer Object, (CETO) is the amount of capacity imports needed by an LDA to meet its reliability criteria under peak load emergency conditions. The PJM Capacity Emergency Transfer Limit (CETL) is the actual amount of capacity that can be imported into an LDA before reaching transmission limits (thermal, voltage, or voltage collapse).

[51] PJM 2026/2027 "Base Residual Auction Report", July 22, 2025, https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2026-2027/2026-2027-bra-report.pdf

[52] Ibid.

[53] Ibid.

[54] Ibid.

needed to meet forecasted peak demand plus reserve margin. Participants in the BRA include generators and demand response providers.

IAs are held three times before the delivery year to adjust commitments made in the BRA based on updated forecasts or changes in resource availability. The first IA is held approximately 20 months before the delivery year (typically September), the second IA is held approximately 10 months before the delivery year (typically July), and the third IA is held approximately 3 months before the delivery year (typically February).[46]

PJM publishes a detailed timeline of activities leading up to the BRA, including a notice of Intent to Offer (approximately 180 days before), MOPR exemption requests (approximately 120 days before), Market Seller Offer Cap notifications (approximately 90 days before). The final planning parameters and accredited UCAP factors are released approximately five months before the delivery year.[47] These steps ensure transparency and compliance with market rules.

PJM is working to resume its three-year-forward planning cycle after many recent adjustments due to regulatory and market design changes. This cycle is meant to provide long-term investment signals and helps maintain reliability across its 13-state and District of Columbia footprint.[48]

2.2.1.5. Resource Accreditation in PJM

PJM's resource accreditation construct, which is centered around the ELCC and enhanced performance- and weather-based modeling, is designed to ensure that capacity resources are evaluated based on their actual contribution to reliability. As described earlier in this report, ELCC is a statistical measure of a resource's ability to contribute to system reliability during peak demand and risk periods. It accounts for availability, performance history, weather impacts, load correlation and outage risks. PJM categorizes resources into ELCC classes. Each class has its own modeling assumptions and performance metrics. PJM defines five resource class categories, with each category having multiple individual classes: Variable Resources (e.g., wind, solar), Limited Duration Resources (e.g., batteries), Combination Resources (e.g., solar + storage hybrids), Unlimited Resources (e.g., thermal generation), and Demand Resources (e.g., demand response).[55]

---

[55] PJM Manual 21B: "PJM Rules and Procedures for Determination of Generating Capability", Revision O2, July 23, 2025, https://www.pjm.com/-/media/DotCom/committees-groups/committees/mrc/2025/20250618/20250618-item-06a---8-manual-21b-revisions---redline.pdf

The Accredited UCAP is derived from ELCC class rating, resource performance adjustment, seasonal capability and deliverability, and weather-based modeling. This value sets a cap on how much capacity a resource can offer in PJM's capacity market.[56]

PJM is enhancing its accreditation to better reflect winter performance, especially for thermal resources. It defines a Winter Installed Capacity (ICAP) based on historical winter peak conditions, Winter Capacity Interconnection Rights (CIRs) granted based on winter deliverability tests, and Annual UCAP that can exceed summer CIRs if winter capability is demonstrated. PJM does not require seasonal pairing, aiming to simplify auction participation by removing the need to pair summer and winter offers.[57]

PJM uses weather rotations, cycling historical weather years, and temperature binning, sorting hours by temperature, to simulate resource performance under various historical weather scenarios. Enhancements include aligning weather days across load and performance models and applying greater weight to recent performance to reflect evolving fleet behavior.[58]

Resource owners must submit detailed data on their hourly output profiles, outage statistics, ambient derates, and performance adjustments. PJM publishes ELCC class ratings and supporting data regularly to ensure transparency.[59]

2.2.1.6. Need Determination in PJM

PJM determines capacity needs through a multi-step process designed to ensure that sufficient resources are available to meet future electricity demand reliably. This process combines demand forecasting, reliability modeling, and resource accreditation to establish the amount of capacity that must be procured. The Forecast Pool Requirement (FPR) represents the total capacity needed to meet expected peak demand plus a reserve margin, derived from the Installed Reserve Margin (IRM). The IRM is determined through probabilistic modeling, load forecasts, and historical performance data to account for uncertainties and maintain reliability under stressed system conditions.

Resources are accredited based on their IICAP, the maximum rated output under ideal conditions, and their (UCAP, which adjusts for forced outages and performance factors to reflect the resource's dependable contribution to reliability. To participate in PJM's capacity

---

[56] Ibid.
[57] PJM, "Accreditation Methodology, PJM Proposal," ELCCSTF presentation, June 17, 2025, https://www.pjm.com/-/media/DotCom/committees-groups/task-forces/elccstf/2025/20250617/20250617-item-02a---elccstf-accreditation-reforms---pjm-proposal.pdf
[58] Ibid.
[59] PJM, "Effective Load Carrying Capability (ELCC)," https://www.pjm.com/planning/resource-adequacy-planning/effective-load-carrying-capability

market, resources must also hold CIRs, which are granted through deliverability and system impact studies and define the maximum capacity a resource may offer. PJM annually updates and publishes ELCC results and UCAP values, which are used in its Base Residual and Incremental Auctions to align resource supply with the system's FPR. Regular backcasts are conducted to validate modeling assumptions and improve forecast accuracy over time.[60]

2.2.2. MISO Capacity Market

Like PJM, MISO serves as an intermediary between energy sellers and buyers in its region through its Planning Resource Auction (PRA). MISO's resource adequacy construct complements the jurisdiction that regulatory authorities have in determining the necessary level of adequacy. It also works in concert with utilities that provide demand forecasts that help drive the development of local and regional requirements. MISO recently began determining resource adequacy on a seasonal, rather than annual, basis and moved to the seasonal capacity construct starting with the delivery year beginning June 1, 2023.

The annual MISO PRA demonstrates if there are sufficient resources and allows market participants to sell capacity, via an auction, to other market participants. MISO sets the capacity requirements in its region for a year starting on June 1 and ending on May 31.[61]

MISO bases the region's capacity needs, including a planning reserve margin, on multiple studies including members' demand forecasts for peak use. It determines the reserve margin from the annual Loss of Load Expectation study. MISO typically accepts auction offers the last four business days of March, applies constraints calculators, then approves or rejects the transactions within the first 20 business days of April.

The PRA is designed to provide a price signal to loads and generators which reflects how well-supplied the MISO market is for resource adequacy. In practice, most LSEs in MISO, particularly vertically integrated utilities, meet the majority of their capacity obligations through owned generation or bilateral contracts, leaving only a small portion of their requirement to be procured through the auction. As a result, the PRA functions as a "residual auction," where the clearing price applies primarily to the remaining MW that LSEs have not already secured through their internal fleets or contracts.

[60] PJM Manual 21B, https://www.pjm.com/-/media/DotCom/documents/manuals/m21b.pdf.
[61] MISO Resource Adequacy Business Practices Manual BPM-011, Section 5.5, https://cdn.misoenergy.org/WPPI%20Feedback%20on%20RASC%20BPM-011-r29%20(20230822-23)%20Redline630187.pdf.

2.2.2.1. Cycle and Timing of Auctions

Seasonal Planning Resource Auctions are conducted in the first twenty business days of April, with results posted near the end of April which is approximately one month before the beginning of the first Season of the associated Planning Year (PY). All four seasonal (Summer, Fall, Winter and Spring) PRAs are conducted in April prior to the following year.[62]

Recognizing that resource adequacy is no longer solely dependent on meeting a potential one-time annual peak day issue, MISO uses a seasonal construct for its PRM evaluations. The seasons include: Summer (June through August), Fall (September through November), Winter (December through February) and Spring (March through May). For these seasons, MISO determines Seasonal Accredited Capacity (SAC) values for all qualified Capacity Resources, and Load Modifying Resources for each Season within the Planning Year. They then calculate LOLE values for the year overall, and for each season.

2.2.2.2. Local Resource Zones (LRZ)

MISO developed Local Resource Zones (LRZ) to reflect the need for an adequate amount of Planning Resources to be in the appropriate physical locations within the MISO Region to reliably meet Demand and LOLE requirements.[63] MISO will provide the details of each LRZ no later than September 1 of the year prior to a Planning Year. MISO Zone 4 is located in the State of Illinois, as well as small sections of Zones 1 and 3 (Figure 2-1).

Figure 2-1: Map of Load Zones in MISO

Source: MISO.org

[62] Ibid., Section 5.5.1.

[63] Ibid., Section 5.2.

The geographic boundaries of each of the LRZs are based upon analysis that considers: (1) the electrical boundaries of Local Balancing Authorities; (2) state boundaries; (3) the relative strength of transmission interconnections between Local Balancing Authorities; (4) the results of previous LOLE studies; (5) the relative size of LRZs; and (6) market seams compatibility. MISO may re-evaluate the boundaries of LRZs if there are changes within the MISO Region including, but not limited to, any of the preceding factors, significant changes in membership, the Transmission System and/or Resources.

2.2.2.3. Bilateral Contracts

In addition to their own resources, MISO Market Participants may enact bilateral contracts with others to achieve their required minimum PRM among other benefits of doing so. LSEs in MISO use bilateral contracts to procure Zonal Resource Credits (ZRCs) to meet their PRMR and ensure sufficient resources to meet forecasted demand plus reserve margins. LSEs can also use these contracts to facilitate the transfer of ZRCs between LSEs. LSEs using the Reliability-Based Demand Curve (RBDC) Opt-Out option can meet their PRMR and LCR obligations through resources secured via bilateral contracts. Lastly, in cases of shortfalls, bilateral contracts can be used to acquire additional ZRCs to meet compliance requirements.

Bilateral contracts play an important role in maintaining resource adequacy by providing load-serving entities (LSEs) with flexibility and cost certainty. These contracts allow LSEs to negotiate terms, prices, and contract durations that align with their specific needs and risk preferences. By securing capacity through bilateral agreements, LSEs can reduce their exposure to the PRA and mitigate the price risks associated with uncertain auction outcomes. In doing so, bilateral contracts can act as financial hedges, locking in capacity costs and protecting customers from price volatility. Hedging on capacity prices carries the risk of locking into contracts that are more expensive than future auction results. Overall, they offer a mechanism for more predictable and stable cost management while supporting the broader objective of ensuring sufficient resources to meet demand.

2.2.2.4. MISO Determination of Resource Adequacy Need

Beginning with the 2028–2029 Planning Year, MISO will replace much of its legacy accreditation framework with the Dependable Load-carrying Operational Limit (DLOL) methodology, recently approved by FERC. Under DLOL, accreditation reflects a resource's expected *operational* ability to contribute during tight system conditions, incorporating factors such as forced outage risk, ambient derates, start-time limitations, and the resource's demonstrated ability to sustain output during net-peak periods. This approach is designed to more accurately represent the real-world contribution of all resource types under increasingly variable system conditions. While elements of the prior Seasonal

Accredited Capacity (SAC) framework will remain relevant during the transition, the DLOL replaces multiple legacy metrics with a unified accreditation method tied to performance during periods of greatest system need.

Because the new DLOL framework will not fully take effect until PY 2028–2029, MISO continues to use SAC-based accreditation for current PRA cycles. Under the SAC construct, thermal resources rely on Generator Verification Test Capacity and outage rates, intermittent resources receive accreditation based on Effective Load Carrying Capability (ELCC), and demand response, storage, and behind-the-meter resources are evaluated according to performance demonstrated during historical peak conditions. As MISO transitions to DLOL, these legacy processes remain in place but gradually will be superseded by a performance-based approach that applies consistently across all technologies.

MISO determines capacity needs through a multi-step process that integrates forecasting, reliability standards, and market mechanisms. Coincident Peak Demand forecasts are submitted by LSEs and validated by MISO to determine both system-wide and zonal capacity requirements. To ensure local reliability, each LSE must meet a portion of its PRMR within its Local Resource Zone (LRZ), reflecting the Local Clearing Requirement (LCR) and accounting for import and export constraints defined by Capacity Import Limits (CIL) and Capacity Export Limits (CEL). System reliability is assessed through probabilistic Loss of Load Expectation (LOLE) analysis, which enforces the standard of no more than one day of expected load loss in ten years (0.1 LOLE). Each LSE's PRMR is calculated as its Coincident Peak Demand plus transmission losses and the applicable Planning Reserve Margin (PRM), with future PRM determinations expected to increasingly rely on the performance-based risk metrics incorporated in DLOL.

Seasonal variations in demand and resource availability are captured through MISO's Seasonal Resource Adequacy assessments across summer, fall, winter, and spring. The PRA then clears any residual capacity needs, using a Reliability-Based Demand Curve (RBDC) to balance supply and demand efficiently. Finally, MISO's decentralized framework allows LSEs flexibility in meeting their PRMR and LCR obligations through bilateral contracts, Fixed Resource Adequacy Plans (FRAPs), or participation in the PRA. This comprehensive process in MISO ensures that resource accreditation reflects the anticipated capability and availability of resources during times of greatest system need, maintaining reliability across all seasons.

2.3. Illinois Resource Adequacy Context

2.3.1. Defining Illinois Resource Adequacy within Markets

As discussed in Chapter 1, Illinois was one of the many states that restructured its electric industry across the late 1990s and early 2000s. In practice, restructuring shifted the day-to-day responsibility for organizing resource adequacy from vertically integrated utilities to the regional transmission organizations (PJM and MISO), which design and administer the primary RA constructs for Illinois utilities and competitive suppliers.

Capacity markets as described in Section 2.2 are the primary way in which resource adequacy is assessed, measured, and compensated for capacity obligations. While the settlement of capacity is assessed for each load serving entity (e.g., Ameren Illinois or ComEd), the restructured nature of the Illinois electricity markets results in several different mechanisms to compensate capacity resources.

For eligible retail customers—defined as the residential and small commercial customers of Ameren, ComEd, and MidAmerican who have not switched to an Alternative Retail Electric Supplier (ARES) or enrolled in real-time pricing—the IPA determines, through its annual Electricity Procurement Plan, how to procure the capacity obligations needed to serve such customers. The IPA, and by extension the utilities, currently utilize different approaches to secure capacity for these residential and small commercial customers, along with hourly pricing default service customers. Through the 2025 Electricity Procurement Plan, the IPA has only sought to secure a capacity hedge on behalf of Ameren eligible retail customers. Subject to the terms of the IPA Electricity Procurement Plan, any capacity obligations not secured through an IPA electricity procurement event are acquired by Ameren through the MISO PRA. ComEd currently secures all capacity obligations for default service customers through the PJM BRA. For default service customers on hourly pricing service, Ameren or ComEd procure capacity through the MISO PRA or PJM BRA, respectively and pass those costs on directly to customers. For ARES customers, ARES are responsible for meeting the energy and capacity needs of their customers. For MidAmerican, the level of exposure to capacity markets faced by eligible retail customers is negligible.[64]

Municipal electric utilities and rural electric cooperatives are LSEs and thus responsible for obtaining the capacity obligations of their customers. Unlike Ameren and ComEd, municipal

[64] In April, 2015, MidAmerican first requested that the IPA procure a portion of the energy needed to serve MidAmerican's eligible retail customer load starting in 2016. Each year since, MidAmerican has remained a part of that process to meet the remaining "portion" of its load not served by MidAmerican owned generation.

utilities and cooperatives either own generation resources or have entered into contracts with generators to meet their resource adequacy needs.

The different mechanisms and different types of LSEs and ARES contribute to challenges in managing future resource adequacy. Each entity is focused on serving the immediate needs of their customers, and it may be difficult to plan for the long-term resource adequacy challenges. For example, an ARES cannot guarantee what its market share will be over time. The ARES may gain or lose customers. As a result, there is an inherent risk for an ARES to enter into long-term capacity contracts. Similarly, the IPA has hedged capacity for Ameren Illinois eligible retail customers as a way to manage price volatility in the MISO PRA rather than creating any long-term capacity commitments. Like an ARES, the IPA must consider the risk of customer switching prior to determining the amount of capacity to hedge.

The prospect of facilitating long-term commitments that are likely to have a meaningful impact to the resource adequacy paradigm is challenging under the Illinois market construct. Capacity prices are difficult to forecast past the next delivery year that will be cleared via auction, with evolving methodologies and processes that underpin those auctions. Furthermore, PJM and MISO are continually changing the market rules in their tariffs which add to the risk and challenges with long-term capacity planning and pricing.

2.3.2. ComEd, Ameren, MidAmerican, and Other Load Serving Entities

Electricity customers in Illinois are served by either an investor-owned utility (e.g., Ameren Illinois, ComEd, MidAmerican, or Mount Carmel Public Utility), a municipal electric utility, or a rural electric cooperative. Approximately 89.8% of customers are served by either Ameren, ComEd, or MidAmerican. Table 2-2 details how many customers are served by each type of electric provider in Illinois.

Table 2-2: Illinois Customers Served by Provider Type (2023)[65]

Provider type	Entity	Customers	Share of Illinois total
Investor-owned utilities (IOUs)	ComEd	4,130,538	68.2%
	Ameren Illinois	1,226,027	20.2%
	MidAmerican (Illinois)	85,611	1.4%

[65] Sources: APPA *2025 Public Power Statistical Report*, "Public Power Data by State and Territory — Illinois;" ICC 2024 Annual Utilities Report; Association of Illinois Electric Cooperatives, "Illinois Electric Co-ops by the numbers."

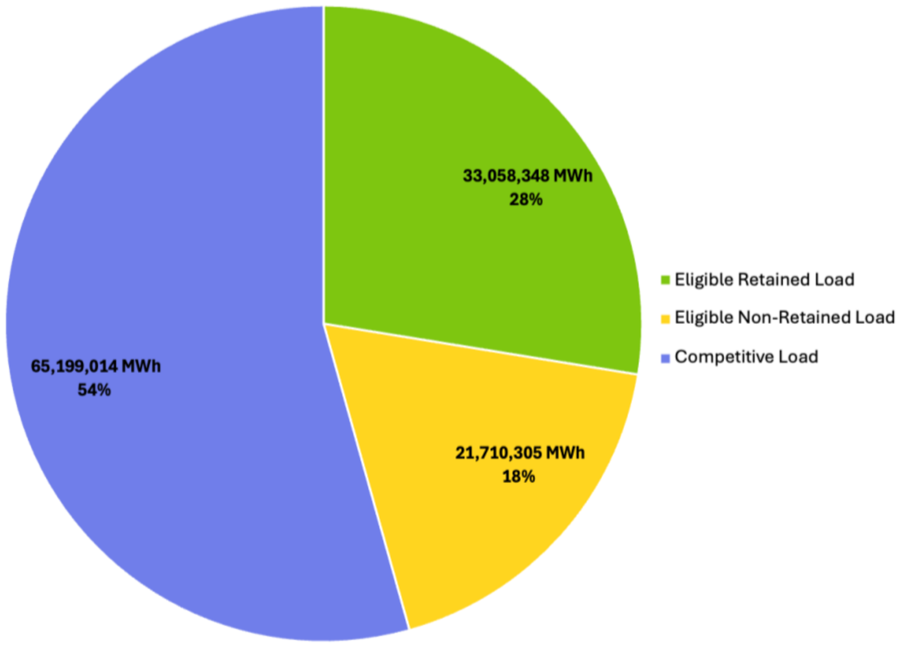
	Mt. Carmel	5,236	0.1%
Public power (munis)	(all Illinois munis)	279,019	4.6%
Electric cooperatives	(all Illinois co-ops)	332,002‡	5.5%
Total		**6,058,433**	**100%**

‡Note: Co-op figure is reported as meters served.

As discussed above, residential and small commercial customers[28] of Ameren, ComEd, and MidAmerican have the ability to take electric service either from their utility at fixed prices, to take electric service from their utility on an hourly or time-of-use basis, or to take service from an ARES. Larger customers must take service either from an ARES or purchase electricity based on wholesale markets by taking hourly or time-of-use pricing service from their utility. Figure 2-2 provides a summary break-down of Investor-Owned Utility Load on Default Service, with 28% of supply being comprised of those customers who are eligible to choose their power supplier and whom chose default service supply, 18% of supply being comprised of eligible customers that switched to an ARES or took hourly pricing rather than default service supply, and the remaining 54% of supply is comprised of large customers who are not eligible to receive default service supply.[66]

[66] IPA 2026 Electricity Procurement Plan (September 29, 2025), pp.18, 25, 32, https://ipa.illinois.gov/content/dam/soi/en/web/ipa/documents/20250929-2026-electricity-procurement-plan-filed-29-sept-2025.pdf.

Figure 2-2: Forecasted 2026-2027 Investor-Owned Utility Load on Default Service



Source: IPA 2026 Electricity Procurement Plan (September 29, 2025)

The large portion of load served by ARES, significantly comprised of large customers who are not eligible for default service supply, creates an added challenge for considering how to manage resource adequacy for customers. As a reminder, the obligation of a LSE is to procure sufficient capacity to meet their customer needs, and that obligation is largely filled through the PJM and MISO capacity markets described above. However, those obligations are not static, the obligations are annually determined and change over time. In any given year, an ARES may gain or lose customers, so their obligation and the default service providers obligations related ebb and flow over time. For customers on default service, the IPA, through its annual electricity procurement plan process, hedges capacity for Ameren Illinois customers, but those hedges are designed to provide protection from price volatility in MISO capacity auctions rather than serve as a capacity planning construct for meeting resource adequacy needs. Like ARES, the IPA must manage the risk of customers leaving default service supply or returning to default service supply, which has restricted the term of a prospective capacity contract and resulted in the use of short-term capacity agreements, not long-term ones.[67]

[67] Illinois energy supply planning faces load migration concerns more acutely than would be the case if customer switching was driven only by individual customer selection. This is due to Section 1-92 of the IPA Act authorizing opt-out municipal aggregation, which can allow for much larger and more sudden shifts in whether residential and small commercial customers are served by competitive suppliers. A list of communities that

2.3.3. Procurement and Roles to Meet Obligations

As a restructured state, there is not a unified procurement approach in Illinois for new or existing resources, with different considerations for ARES, default service, and municipal utilities/rural electric cooperatives.

ARES are not regulated and can determine their own approaches for procuring power for their customers. In some cases, ARES are owned by or affiliated with generation resources that can be accessed to meet their supply obligations; in other cases, the ARES may enter into a variety of market transactions to secure necessary load and related services. These transactions are typically short-term transactions. A notable exception would be the recent deal announced between Constellation and Meta to provide supply from the Clinton nuclear plant.[30] ARES do not have any renewable or clean energy procurement obligations.

For default service customers, the IPA develops an annual electricity procurement plan and through that plan assesses load forecasts, including estimating switching between default service and ARES service, market conditions, and other factors to develop a proposed set of procurements to meet the needs of default service customers. The IPA then conducts procurements through its Procurement Administrator to procure the needed resources, with the applicable utility serving as the counterparty to the resulting contracts.

To support the development of new renewable energy resources, the IPA develops a biennial Long-Term Renewable Resources Procurement Plan that includes how the IPA will conduct procurements for RECs from new utility-scale wind, solar, hydroelectric, and brownfield projects, how the IPA will implement the Illinois Shines and Illinois Solar for All programs to support the development of community solar and photovoltaic distributed generation projects, the parameters of the Large Customer Self-Direct Program, and the requirements for program participants to meet Minimum Equity Standards. Funding to support the programs and procurements in the Long-Term Plan are supported by all retail customers of Ameren, ComEd, and MidAmerican. For more information on the Long-Term Plan, see Section 3.1.3 below.

The IPA's annual Electricity Procurement Plan and the biennial Long-Term Renewable Resources Procurement Plan both go through a process of being released as a draft plan for stakeholder feedback and then are litigated before the ICC in docketed proceedings. The ICC approves each Plan and may order modifications in those docketed proceedings. The ICC also approves the results of each competitive procurement conducted by the IPA and the approval of contracts for RECs from community solar and photovoltaic distributed

have pursued a referendum authorizing municipal aggregation and basic terms of any such agreements can be found here: https://plugin.illinois.gov/municipal-aggregation/municipal-aggregation-list.html.

generation projects that result from the IPA's programs. Illinois utilities then are the counterparties for the resulting contracts. This process was first developed for electricity procurement with the establishment of the IPA in 2007, and then later extended to renewable resources functions as a set of checks and balances, with the IPA tasked with developing plans, and the ICC approving the plans and subsequent procurements. In this way the IPA can focus on its statutorily defined role to research, analyze, and consider the dynamic elements of procurement and program design and weigh competing interests and considerations. The ICC in turn is able to use its powers as a regulatory agency to consider the viewpoints of parties in docketed proceedings to approve and modify plans.

A limitation of this structure is that each agency is limited in its role. The IPA cannot develop or propose procurements for resources beyond those specified in the IPA Act. Similarly, the parameters for approving plans and procurements by the ICC is set out in the IPA Act and the Public Utilities Act. A clear example of this limitation is that the IPA can only procure capacity in a very limited scope: the hedging of capacity for eligible retail customers, a limited group of retail customers. There is not an existing process that would allow for a broader scope of capacity procurement to address resource adequacy concerns.

2.4. Key Resource Adequacy Risk Factors & Industry Trends

This section describes the key risk factors and industry trends shaping resource adequacy outcomes and capacity market pricing in PJM and MISO. While recent attention has focused on changes to capacity accreditation methodologies and the introduction of price caps and floors, these developments occur alongside a broader set of structural forces influencing capacity needs and costs. These include accelerating load growth and changing seasonal usage patterns, rising demand from data centers, the pace and composition of generator retirements, persistent constraints on new resource additions due to interconnection and supply chain challenges, and evolving federal and state policy frameworks. Together, these factors interact to affect both the quantity of dependable capacity required to meet reliability standards and the prices needed to attract and retain that capacity in regional markets.

2.4.1. Implications of Evolving Accreditation for Resource Capacity

As PJM and MISO modernize their accreditation frameworks, new ELCC- and UCAP-based methods are significantly reducing the accredited capacity of many thermal resources, particularly units that have shown higher forced outage rates or weaker winter performance. These changes do not create "new" reliability needs so much as reveal risk that was previously masked by overly optimistic nameplate- or ICAP-based credits. When resources are re-scored using more granular weather, outage, and performance data, systems often appear shorter on dependable capacity than past accounting suggested, which in turn drives higher procurement quantities and, in some cases, higher clearing prices in capacity auctions to meet the same LOLE and PRM standards.

For Illinois, this evolution in accreditation is best understood as a recalibration of how much dependable capacity actually exists in PJM and MISO. By correcting historic overestimation of thermal capability, especially under extreme conditions, new accreditation rules better align market outcomes with the reliability risks customers already faced. In the near term, this can increase procurement volumes and costs; over the longer term, it provides a more accurate signal of the portfolio additions, retirements, and complementary investments (such as transmission and demand-side resources) needed to sustain resource adequacy for Illinois customers.

2.4.2. Impacts of Price Caps

Price caps and floors in RTO capacity auctions, such as those recently implemented in PJM, can have significant impacts on market dynamics. In the immediate term, price caps limit volatility by preventing clearing prices from reaching extreme highs during periods of tight supply and demand. For example, PJM's 2026/27 auction reached the FERC-approved cap of $329.17/MW-day; without the cap, prices would have cleared at $388/MW-day.[68] Even with the price cap in place, capacity costs still rose 9.5% year over year, contributing to retail bill increases of 1.5–5% for many customers.[69] At the same time, price floors can create revenue certainty for developers, helping stabilize investment expectations and improving access to financing for new resources.[70] Unlike PJM, MISO does not currently have price floors or caps for capacity prices cleared through the PRA.

High capacity prices are meant to attract new resources when supply is tight, but new resource development may face many other challenges as well, including interconnection processes, siting and permitting, sourcing major equipment from global supply chains, and market risks. Looking ahead, continued evolution in capacity market design is occurring. Even with caps in place, PJM prices have increased nearly tenfold since 2024, pointing to underlying structural issues like transmission congestion and slow interconnection timelines rather than short-term market distortions.[71] Policymakers and regulators are exploring reforms such as accelerated interconnection processes, updates to seasonal

---

[68] "RTO Insider: PJM Capacity Prices Hit $329/MW-day Price Cap," Advanced Energy United, Devin Leith-Yessian, July 22, 2025, https://blog.advancedenergyunited.org/articles/rto-insider-pjm-capacity-prices-hit-329/mw-day-price-cap.

[69] Ibid.

[70] "What PJM's New Capacity Market Cap & Collar Means for Market Participants," Syso Technologies (May 5, 2025): https://www.sysotechnologies.com/2025/05/06/pjm-new-capacity-market-cap-and-collar/.

[71] RTO Insider (July 22, 2025).

accreditation methods, and greater state involvement in capacity planning.[72] These developments reflect a broader shift toward balancing consumer protection, reliability, and investment efficiency in increasingly constrained and policy-driven electricity markets.

2.4.3. Load Growth and Seasonal Usage Patterns

Over the past two decades, U.S. electricity demand remained relatively flat as population and economic growth were largely offset by efficiency improvements and a shift from manufacturing to service-based industries.[73] Looking ahead, the Energy Information Administration (EIA) projects average annual electricity consumption growth of 1.7% from 2020 to 2026, led by the commercial (+2.6%) and industrial (+2.1%) sectors, with more modest residential growth (+0.7%).[74]

Data centers are becoming a major driver of U.S. electricity demand growth. In 2023, they accounted for roughly 4.4% of total U.S. electricity consumption—rising sharply from 58 TWh in 2014 to 176 TWh in 2023.[75] Their impact is projected to grow substantially in the coming years, with forecasts suggesting that by 2028, data centers could consume between 6.7% and 12% of total U.S. electricity, equivalent to 325–580 TWh, potentially tripling current usage.[76] Within the commercial sector, the Energy Information Administration projects that computing, including data centers, will rise from 8% of commercial electricity use in 2024 to 20% by 2050.[77] This rapid growth is outpacing efficiency improvements and reversing earlier declines in electricity intensity per square foot, signaling a fundamental shift in commercial energy consumption patterns.

Historically, residential electricity consumption in the U.S. showed strong seasonality, with clear peaks in both summer and winter. Summer peaks were largely driven by air conditioning loads, while winter peaks reflected a combination of electric heating and the

---

[72] "Drivers of PJM's Capacity Market Price Surge and its Impacts on Electricity Consumers in the District of Columbia," Synapse Energy Economics, Inc., Prepared for the Office of the People's Counsel for the District of Columbia (April 25, 2025): https://opc-dc.gov/wp-content/uploads/2025/05/PJM-Capacity-Market-Report-FINAL-OPC-Synapse-7.15.pdf.

[73] "After more than a decade of little change, U.S. electricity consumption is rising again," U.S. Department of Energy (DOE) Energy Information Administration (EIA) (May 13, 2025): https://www.eia.gov/todayinenergy/detail.php?id=65264.

[74] US Energy Information Administration: https://www.eia.gov/todayinenergy/detail.php?id=65264.

[75] "DOE Releases New Report Evaluating Increase in Electricity Demand from Data Centers," U.S. Department of Energy (December 20, 2024): https://www.energy.gov/articles/doe-releases-new-report-evaluating-increase-electricity-demand-data-centers.

[76] Ibid.

[77] "Electricity Use for Commercial Computing Could Surpass Space Cooling and Ventilation," U.S. EIA (June 24, 2025): https://www.eia.gov/todayinenergy/detail.php?id=65564.

electricity required to power components of heating systems such as fans and pumps.[78] This pattern held for much of the past decade, as both heating and cooling needs shaped annual load profiles across most regions. In recent years, this balance has shifted toward higher summer electricity use. Hotter temperatures, more frequent heatwaves, and increased reliance on air conditioning, which accounts for roughly 19% of household electricity use, have driven steady growth in summer demand.[79] Expanding commercial cooling needs, including those from data centers, have further amplified this trend.[80] While near-term winter load may decrease due to an increase in average temperatures, winter electricity demand is expected to increase in MISO and PJM, driven largely by electrification and data centers.[81] PJM's winter peak is expected to experience an average of 3.8% annual growth in winter peak over the next 10 years, and 2.4% over the next 20 years.[82]

Seasonal patterns also vary by sector. The residential sector continues to exhibit the greatest variation, with pronounced sensitivity to temperature extremes in both summer and winter. The commercial sector shows moderate seasonality, with higher summer peaks from cooling loads but limited winter variation, while the industrial sector remains relatively stable year-round, driven more by economic activity than weather conditions.[83] These evolving patterns have important implications for grid planning: system operators must increasingly plan for higher summer peaks, particularly in regions with growing data center and electrification demands, while maintaining flexibility during lower-demand shoulder seasons used for maintenance.[84] Peak demand records are now more frequently set in summer months, as seen in July 2025, reflecting the growing importance of managing summer reliability challenges.[85]

---

[78] "Homes show greatest seasonal variation in electricity use," EIA Today in Energy (March 4, 2013): https://eia.gov/todayinenergy/detail.php?id=10211.

[79] "Residential Energy Use," U.S Environmental Protection Agency (EPA), p.1 (December 2024): https://www.epa.gov/system/files/documents/2024-12/residential-energy_td.pdf.

[80] "After More than a decade..." EIA (May 13, 2025): After more than a decade of little change, U.S. electricity consumption is rising again - U.S. Energy Information Administration (EIA).

[81] MISO Long-Term Load Forecast Whitepaper (2024): https://cdn.misoenergy.org/MISO%20Long-Term%20Load%20Forecast%20Whitepaper_December%202024667166.pdf.

[82] PJM Long-Term Load Forecast Report (2025): https://www.pjm.com/-/media/DotCom/library/reports-notices/load-forecast/2025-load-report.pdf.

[83] "Homes show greatest seasonal variation..." EIA (March 4, 2013): Homes show greatest seasonal variation in electricity use - U.S. Energy Information Administration (EIA).

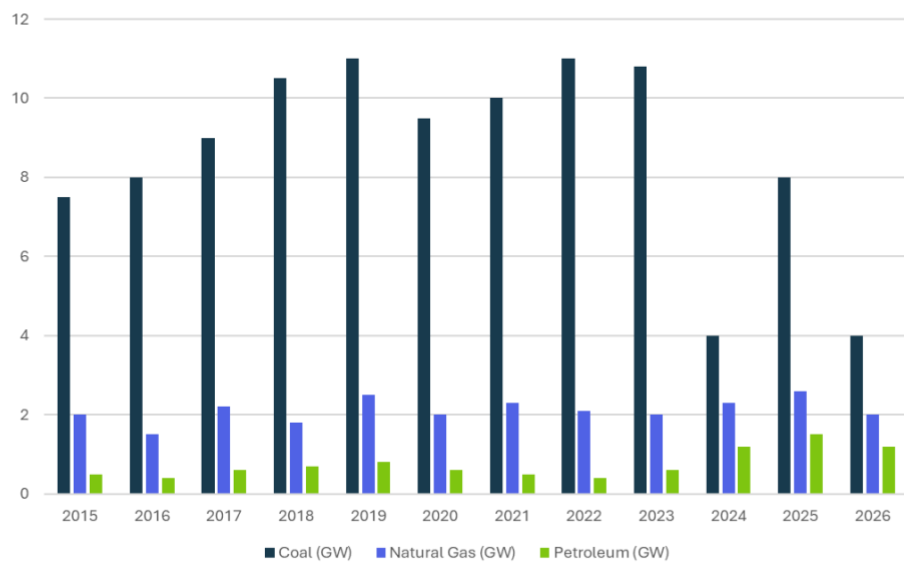
[84] "What is the shoulder season in electricity markets?", EIA *Today in Energy* (December 16, 2024): https://eia.gov/todayinenergy/detail.php?id=64044.

[85] "U.S. electricity peak demand set new records twice in July," EIA *Today in Energy* (August 5, 2025): https://www.eia.gov/todayinenergy/detail.php?id=65864.

2.4.4. Generator Retirements: The National Perspective

This load growth and shifts is seasonal electricity usage must also be considered against the backdrop of generator retirements across the country. As seen in Figure 2-3, from 2015-2024 there was an average of 9.8 GW of coal generation retired each year, however, in 2024, coal retirements dropped sharply to 4.0 GW, the lowest since 2011.[86] Natural gas retirements have varied, but in 2024, only 2.4 GW of natural gas capacity was retired, representing 0.5% of the fleet.[87] Petroleum has typically been a small share of retirements, with 1.6 GW retired in 2024.[88] In 2024 just 7.5 GW of generation retired, the lowest annual total since 2011.[89]

Figure 2-3: U.S. Electric Generation Retirements by Fuel Type (2015-2026)



Source: US EIA

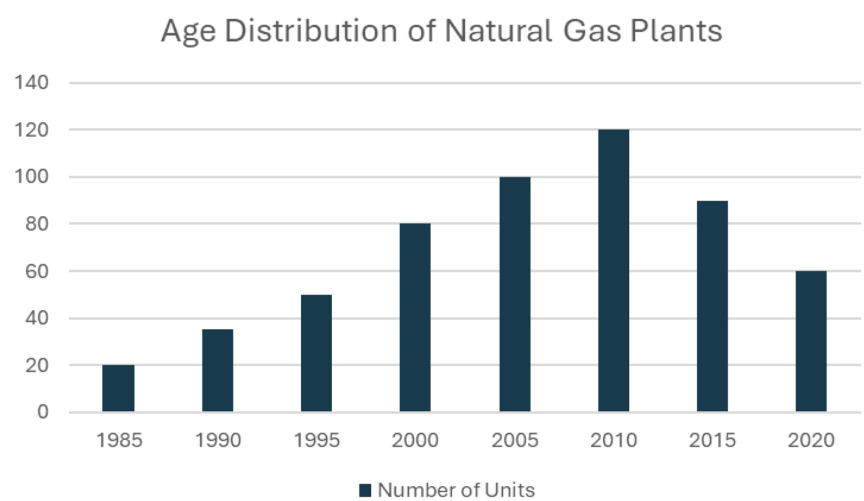
Looking ahead, there is a sharp increase in retirements expected in 2025, with 12.3 GW of total retirements planned, a 65% jump from 2024.[90] This is in part driven by the age of the coal fleet in the US. The average age of coal-fired electric generation capacity in the U.S. is approximately 45 years, based on the U.S. Energy Information Administration data, which

[86] "Planned retirements of U.S. coal-fired electric-generating capacity to increase in 2025," U.S. EIA *Today in Energy (*February 25, 2025): https://www.eia.gov/todayinenergy/detail.php?id=64604.
[87] "US electric-generating capacity retirements in 2024 to be lowest in 16 years: EIA," S&P Global (February 20, 2024): https://www.spglobal.com/commodity-insights/en/news-research/latest-news/electric-power/022024-us-electric-generating-capacity-retirements-in-2024-to-be-lowest-in-16-years-eia.
[88] EIA *Today in Energy* (February 25, 2025).
[89] Ibid.
[90] Ibid.

notes that most coal plants were built in the 1970s and 1980s.[91] The average retirement age for coal plants is around 50 years.

In contrast to coal, the average age of natural gas-fired electric generation capacity in the U.S. is approximately 22 years.[92] Many natural gas plants were built in the early 2000s, especially combined-cycle gas turbine (CCGT) units, as seen in Figure 2-4. The newest plants, built since 2014, have higher efficiency and capacity factors (around 66%). Older plants, commissioned in the 1980s, still operate but with lower efficiency (capacity factors around 36%). The fleet includes a mix of technologies: combined-cycle gas turbines (CCGT, 58%), simple-cycle gas turbines (26%), steam turbines (15%), and internal combustion engines (1%).[93]

Figure 2-4: Age Distribution of Natural Gas-Fired Generating Plants in the US



Source: US EIA

U.S. generation retirements are being driven by a rapid shift away from coal, as aging infrastructure, environmental regulations, and competition from renewables and natural gas that make many plants uneconomic to operate. Older natural gas units are increasingly being replaced by more efficient aeroderivative turbines, while renewable additions continue to surge, projected at 26 GW of solar and 8 GW of wind in 2025 alone.[94] However,

[91] "Nearly 60 GW of coal-fired capacity to retire by 2035, EIA says," Power Engineering *Factor This*, Kevin Clark (December 20, 2021): https://www.power-eng.com/coal/nearly-60-gw-of-coal-fired-capacity-to-retire-by-2035-eia-says.

[92] "Natural gas-fired generation, the backbone of U.S. electricity generation, varies by region," EUCI *Energize Weekly* (February 28, 2024): https://www.euci.com/natural-gas-fired-generation-the-backbone-of-u-s-electricity-generation-varies-by-region.

[93] "Use of natural gas-fired generation differs in the United States by technology and region," *Today in Energy*, (February 22, 2024): https://www.eia.gov/todayinenergy/detail.php?id=61444.

[94] Ibid.

the pace and timing of retirements remain subject to change as policy, reliability, and market conditions continue to evolve.

2.4.5. Resource Additions & Constraints

Interconnection queues have become one of the most significant barriers to bringing new generation online, prompting major reforms at the federal and RTO levels to improve transparency, efficiency, and readiness of projects entering the grid. FERC Order No. 2023 replaced the long-standing “first-come, first-served” model with a “first-ready, first-served” framework that emphasizes site control, financial readiness, and clustered studies to reduce speculative activity and study backlogs. These requirements, along with new withdrawal penalties and proportional cost allocation rules, aim to ensure that viable, construction-ready projects advance through the queue while maintaining grid reliability and open-access principles established under Order No. 888. Together, the federal reforms set the foundation for a more predictable and equitable process that supports the integration of diverse resources needed to meet future reliability and policy goals.

Building on this federal direction, both MISO and PJM have undertaken sweeping queue reforms to address acute regional delays. MISO strengthened its Definitive Planning Phase (DPP) requirements by raising milestone payments, tightening site control standards, increasing withdrawal penalties, and implementing a Queue Cap Tracker to better manage study volumes beginning in 2025. It also created the Expedited Resource Addition Study (ERAS) to fast-track projects needed for near-term reliability. PJM is similarly transitioning to a clustered “first-ready, first-served” process, dramatically reducing its transition backlog and accelerating the timeline to secure interconnection agreements, while launching initiatives like the Reliability Resource Initiative and a proposed Expedited Interconnection Track to prioritize ready-to-build generation and storage projects. Despite progress, both RTOs continue to face challenges related to transmission upgrades, permitting, and alignment with state policies, underscoring the ongoing need for coordinated planning and continued reform. Further details on interconnection reform efforts at each RTO can be found in Appendix B.

2.4.6. Federal Policy Driving Price & Market Uncertainties

2.4.6.1. Effects of Rolling Back IRA Incentives

Due to the enactment of the FY 25 Federal Reconciliation Bill passed on July 4th, 2025, the rolling back of federal incentives established under the Inflation Reduction Act (IRA) has significant implications for electric system planning, resource adequacy, and long-term reliability. The loss of IRA incentives may increase system costs and create new reliability challenges. Without the cost advantages provided by clean energy tax credits, utilities will depend more heavily on gas-fired generation, leading to higher fuel and operating expenses that could raise delivered electricity prices by 7–10% by the end of the decade.[95] Slower renewable and storage deployment will also reduce reserve margins and increased reliance on thermal resources that have longer development timelines. With demand expected to rise by roughly 50% over the next ten years, these dynamics may make it more difficult to maintain reliability during the transition to a higher-load, more electrified system.[96]

2.4.6.2. FY25 Reconciliation Bill and Foreign Entity of Concern Designation Implications on Clean Energy Supply Chains

The Foreign Entity of Concern (FEOC) designation refers to companies that are owned, controlled, or influenced by governments of China, Russia, Iran, or North Korea.[97] Under the Inflation Reduction Act, FEOC restrictions initially applied to the Section 30D Clean Vehicle Credit, which prohibits the use of battery components or critical minerals sourced from such entities starting in 2024–2025.[98] The FY25 Reconciliation Bill broadened the scope of FEOC rules to include six additional tax credits.[99] It also introduced two new classifications: Specified Foreign Entities (SFE),[100] which include companies tied to China's military, implicated in forced labor practices, or banned under federal procurement rules, and Foreign Influenced Entities (FIE), defined as firms with significant ownership or control (over 25%) by covered nations or those receiving material support from them.[101] Projects are now ineligible for credits if they source components or make payments exceeding 5% of total project costs to prohibited entities, or if they enter licensing agreements above $1 million.[102] These changes, combined with accelerated credit phase-outs, which requires most clean

---

[95] Ibid.
[96] Ibid.
[97] The statutory definition of "Foreign Entity of Concern" (FEOC) originates from Section 40207 of the Bipartisan Infrastructure Law (BIL), also known as the Infrastructure Investment and Jobs Act (IIJA) (42 U.S.C. §18741(a)(5)).
[98] "Foreign Entity of Concern Requirements in the Section 30D Clean Vehicle Credit," (September 30, 2024): https://www.congress.gov/crs_external_products/IN/HTML/IN12322.web.html.
[99] "Understanding foreign entity of concern (FEOC) provisions in the OBBBA of 2025," Baker Tilly (July 30, 2025): https://www.bakertilly.com/insights/understanding-foreign-entity-of-concern.
[100] Ibid.
[101] "A practical discussion of the One Big Beautiful Bill's (OBBB) Foreign Entity of Concern (FEOC) rules," Norton Rose Fulbright LLP (October 1, 2025): https://www.projectfinance.law/media/6082/nrf-presentation-a-practical-discussion-of-feoc-rules-10012025-revised-100125-2504922632.pdf.
[102] "Key Provisions of the One Big Beautiful Bill (H.R.1) Related to Foreign Ownership and Foreign Supply (FEOC)," Foley & Lardner LLP (June 13, 2025): https://www.foley.com/p/102kflw/key-provisions-of-the-one-big-beautiful-bill-h-r-1-related-to-foreign-ownership/.

energy projects to be placed in service by 2027, have tightened timelines and compliance requirements for developers and utilities.[103]

These revisions introduce new supply chain and resource adequacy challenges. Many renewable, battery, and inverter components currently rely on suppliers now classified as SFEs, forcing a rapid shift toward alternative sources. This transition is expected to increase project costs and extend development timelines, particularly for solar and storage.[104] Developers must implement detailed ownership tracing and procurement audits to verify FEOC compliance, adding administrative complexity and potential financial exposure if violations trigger credit recapture.[105]

In the broader market, these supply chain constraints are likely to contribute to upward pressure on electricity prices. Restricting access to components from major foreign suppliers amplifies scarcity, increasing the cost of critical equipment such as transformers, batteries, and solar modules. These dynamics can lead to tighter capacity conditions and higher clearing prices in regional capacity markets, as seen in PJM's recent auctions. Meanwhile, domestic manufacturing expansion, though aligned with long-term policy goals, often entails higher labor and input costs in the near term.

[103] "One Big Beautiful Bill: New Law Disrupts Clean Energy Investment," Latham & Watkins LLP, *Client Alert* (July 8, 2025): https://www.lw.com/admin/upload/SiteAttachments/One-Big-Beautiful-Bill-New-Law-Disrupts-Clean-Energy-Investment.pdf.
[104] Ibid.
[105] Norton Rose Fulbright LLP (October 1, 2025).

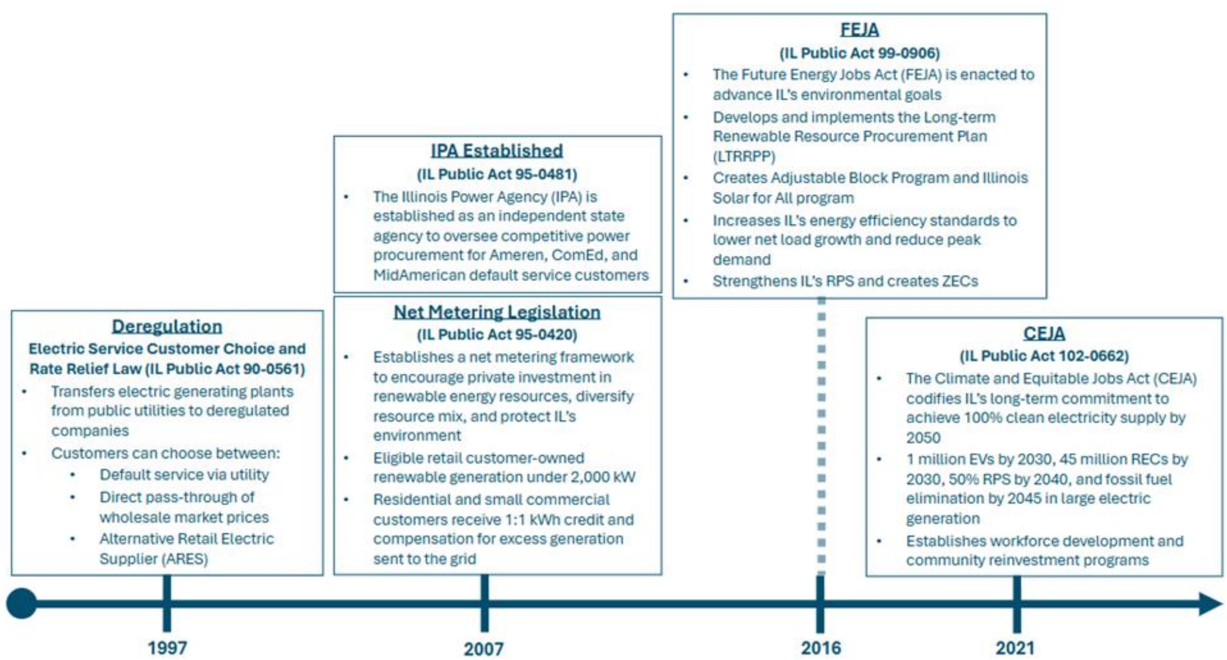
3. State of Illinois Policy

3.1. Legislative Summary on Emissions & Clean Energy Goals

Illinois clean energy and emissions policies have been developed through a series of major legislative actions that build upon the state's restructured, market-based electric system established under the 1997 Electric Service Customer Choice and Rate Relief Act. Over time, laws such as the Illinois Power Agency Act, which created the Illinois Power Agency and the Renewable Portfolio Standard, the Future Energy Jobs Act (FEJA), and CEJA have progressively advanced the state's environmental and clean energy goals. These statutes introduced renewable and zero-emission energy targets, expanded energy efficiency and community solar programs, and established mechanisms such as renewable energy credits (RECs) and zero emission credits (ZECs) to support decarbonization while maintaining competitive market structures. Collectively, these policies have guided Illinois toward a more reliable, equitable, and sustainable energy future grounded in both market efficiency and public policy objectives.

3.1.1. History of Clean Energy Policy in Illinois

Figure 3-1: Timeline of Illinois Energy Legislation



In 1997, Illinois became one of only a handful of states to restructure its electric markets. Pursuant to the Illinois Electric Service Customer Choice and Rate Relief Act of 1997, electric distribution was maintained as a fully regulated utility service, but transmission planning and control gravitated to independent RTOs. Generation resources were spun off as independent entities, separate from the regulated distribution and transmission systems, to participate in the wholesale market, which created a path towards retail competition for electric supply service. The idea behind the electricity industry restructuring set in motion by the Illinois Electric Service Customer Choice and Rate Relief Act of 1997 was that resource adequacy could be more efficiently provided through market mechanisms, particularly competitive wholesale power markets.

Since this restructuring, Illinois has enacted environmental policies that coexist with its competitive market-based approach. Since 2008, the Illinois Renewable Portfolio Standard has required a percentage of each utility's total procured supply to serve its customers be generated from cost-effective renewable energy resources. Also starting in 2008, Illinois has required Illinois utilities, through the Energy Efficiency Portfolio Standard, to use cost-effective energy efficiency and demand-response measures to reduce delivery load.

Public Act 95-0418, known as the Illinois Power Agency Act (IPA Act), took effect in August 2007. The IPA Act created the Illinois Power Agency and established the Illinois Renewable Portfolio Standard. It declared that energy efficiency, demand-response measures, and renewable energy are resources underused in Illinois and that "the health, welfare, and prosperity of all Illinois citizens require the provision of adequate, reliable, affordable, efficient, and environmentally sustainable electric service at the lowest total cost over time, taking into account any benefits of price stability."[106]

The Act required investment in energy efficiency and demand-response measures and supported the development of clean coal technologies and renewable resources. It directed ComEd and Ameren Illinois to procure a diverse electricity supply portfolio, including cost-effective renewable resources that "will reduce long-term direct and indirect costs to consumers by decreasing environmental impacts and by avoiding or delaying the need for new generation, transmission, and distribution infrastructure."[107]

The IPA was directed to develop electricity procurement plans, beginning in 2008 and updated on an annual basis, that also included renewable energy resources sufficient to achieve the standards of the Illinois RPS. The procurement plans from these earlier statutory provisions (having since been superseded by new provisions in 2017 and 2021 discussed later in this chapter) required a minimum percentage of each utility's total supply be

[106] 20 ILCS 3855/1-5(1).
[107] 20 ILCS 3855/1-5(6).

generated from cost-effective renewable energy resources, starting with a minimum of 2% in 2008 and reaching a minimum of 25% by June 1, 2025.

The Act set sub-targets such that of the renewable energy resources procured, 75% were required to come from wind, 6% from photovoltaics, and 1% from distributed generation. Prior to June 1, 2011, resources from Illinois were explicitly prioritized (looking only to adjoining states if none was available, and then to elsewhere). After June 1, 2011, the RPS allowed resources in adjacent states to also be included as the first priority with Illinois resources, with the ability to source resources from elsewhere if there were insufficient resources available to meet targets.

While the annual renewable resources procurement plans generally called for the purchase of RECs, the IPA, as part of its 2009 Annual Procurement Plan, held a 2010 procurement event for "bundled" (energy and REC) 20-year contracts from renewable energy suppliers.

The IPA's renewable resources procurement plans, which were part of the annual procurement plans developed primarily to procure the energy, capacity, and other standard wholesale product requirements, only applied to "eligible retail customers," or those customers still taking default supply service from their incumbent electric utility (ComEd and Ameren Illinois, and starting in 2016, MidAmerican).

The ARES were subject to a similar but separate renewable portfolio standard. Adopted in 2009, the ARES were also required to meet a percentage-based renewable portfolio standard as a percentage of their sales. However, each ARES could satisfy its obligation by making alternative compliance payments at the rate paid by the electric utility's eligible retail customers for no less than 50% of its obligation, and it could self-procure RECs for the remainder of its obligation. The RECs purchased by ARES could be produced by facilities anywhere within the regional transmission territories of PJM or MISO.

As the annual renewable resources budget was tied to the load of eligible retail customers, customer switching to and from ARES service caused significant volatility in each year's budget available for the IPA's renewable resources procurements. This budget uncertainty made entering into any additional long-term agreements unworkable and caused purchases by the utilities to be mostly one-year REC contracts. One notable exception was the Supplemental Photovoltaic Procurement, pursuant to 2014's Public Act 98-0672, which resulted in the development of roughly 30 MWs of new distributed generation photovoltaics in Illinois through five-year REC contracts.

The IPA Act limited the total renewable energy resources procured in 2008 to no more than 0.5% of the amount paid per kilowatt hour by the utilities' eligible retail customers during the year ending May 31, 2007. This cap increased annually to no more than 2.015% of the amount paid per kilowatt hour by those customers during the year ending May 31, 2007, by 2011. This limit remained in place until Public Act 102-0662, referred to as the Climate and Equitable Jobs Act, or CEJA, raised it to 4.25% of the amount paid per kilowatt hour by customers during the year ending May 31, 2009, beginning in 2022.

3.1.2. Net Metering Legislation

A separate piece of legislation, Public Act 95-0420, also effective August 2007, established a net electricity metering framework under Section 16-107.5 of the PUA, with the intent to "encourage private investment in renewable energy resources, stimulate economic growth, enhance the continued diversification of Illinois' energy resource mix, and protect the Illinois environment." It established that any retail customer that owned or operated a solar, wind, or other eligible renewable electrical generating facility, such as solar, wind, dedicated energy crops, anaerobic digestion, renewable fuel cells or small hydro, with a rated capacity of not more than 2,000 kilowatts that is located on the customer's premises and was intended primarily to offset the customer's own electrical requirements was eligible for net metering. Starting April 2008, both customers receiving supply from the electric utility or an ARES were eligible for net metering.

Residential and small commercial customers on a fixed supply rate (either from the electric utility or an ARES) received full retail net metering (supply and delivery credits) through a 1:1 per-kWh credit. This meant that for every 1 kWh of energy a net metering customer exported to the grid, the customer received a 1 kWh bill credit. These resulting credits offset any kWh of energy the net metering customer used from the grid. For residential customers, this kWh credit included all variable charges on their bill. Large commercial and industrial customers received supply-only net metering credits for excess generation sent to the grid. Residential customers and small commercial customers that were on the hourly supply rate also received compensation for each kWh of excess generation sent to the grid. Due to the nature of the hourly supply option, each kWh was compensated at the hourly rate at the time the energy was provided to the grid, and therefore the compensation was presented on the bill as a monetary bill credit rather than a kWh credit.

Net metering customers retained ownership of all renewable attributes, RECs, and emissions credits from their systems. Electricity providers had to offer net metering until participation reached 1% of the provider's previous-year peak load, though they could voluntarily exceed this threshold. Providers could also choose whether to allow meter aggregation.

3.2. The Future Energy Jobs Act or FEJA

In December 2016, Illinois enacted Public Act 99-0906, also known as the Future Energy Jobs Act (FEJA), which became effective June 1, 2017. FEJA further advanced Illinois' efforts to meet environmental goals. This section briefly summarizes the most relevant aspects of FEJA for the Resource Adequacy Study, and a more detailed summary of the legislation can be found in Appendix C.

FEJA reshaped Illinois' supply mix in ways directly tied to long-term resource adequacy. By accelerating the development of distributed, community, and utility-scale renewable resources and preserving existing nuclear generation, FEJA expanded and stabilized the clean resource portfolio available to meet Illinois' load over time. Its creation of the Adjustable Block Program and Illinois Solar for All provided predictable, bankable REC prices that enabled rapid solar deployment, while updates to Illinois' energy efficiency standards set higher cumulative energy efficiency targets to lower net load growth and reduce peak demand. For resource adequacy, these programs contributed to both sides of the reliability equation: they aimed to increase supply diversity while lowering demand.

FEJA also strengthened Illinois' renewable portfolio standard and centralized renewable procurement under IPA's Long-Term Renewable Resources Procurement Plan (IPA Long-Term Plan), as described further below. This transition created a more stable and scalable mechanism for bringing new renewable resources onto the grid, an important prerequisite for ensuring sufficient qualifying capacity in both PJM and MISO over time. Coupled with expanded net-metering provisions, smart-inverter requirements, and distributed-generation rebates, these changes intended to accelerate behind-the-meter solar adoption.

Another consequential provision of FEJA for reliability was the creation of the Zero Emission Credit (ZEC) program, which ensured continued operation of at-risk nuclear units through 2027. Preserving these large, capacity-dense generators avoided abrupt capacity shortfalls and mitigated the risk of large upward shocks to Illinois' resource adequacy position, particularly in ComEd's territory that rely heavily on nuclear baseload units for both energy and capacity. FEJA's nuclear preservation provisions ensured that Illinois maintained a balanced supply portfolio while its renewable and distributed-energy programs ramped up.

3.3. IPA Long-Term Renewable Resources Procurement Plan

As established under FEJA, the IPA develops a Long-Term Renewable Resources Procurement Plan (Long-Term Plan) on a biennial basis. The Long-Term Plan serves as a roadmap for renewable energy programs and procurements managed by the IPA, with a focus on incentivizing the development of new renewable energy generation.

Key activities outlined through the Long-Term Plan include:

- Competitive procurements to support the development of new utility-scale wind and hydropower projects, utility-scale solar, and brownfield site photovoltaic projects. Subject to the passage of P.A. 99-0906, competitive procurements include a locational standard, providing the opportunity for projects in adjacent states to Illinois to provide RECs, but only if they meet the public interest criteria defined in law and effected through the Long-Term Plan.
- The Illinois Shines Program (also known as the Adjustable Block Program) to support the development of distributed generation solar projects for Illinois homes and businesses, and the development of community solar projects. The Illinois Solar for All (ILSFA) Program to support solar for income-eligible households and communities.
- A large customer self-direct program through which large electric customers are eligible for bill credits through the Self-directed procurement of Renewable Energy Credits (RECs)—certificates that represent the environmental benefits of electricity generated from renewable energy generation.
- Consumer protection requirements applicable to IPA incentive programs.
- The Minimum Equity Standard (MES), a statutorily mandated requirement that establishes a minimum level of equity-eligible persons for the project workforce of entities participating in the IPA's Illinois Shines Program, Self-direct Program or competitive renewable energy procurements.

The objectives behind these renewable energy programs and procurements are to provide support to renewable projects, enabling their development and ultimately achieving the Illinois clean energy targets. Details of the progress to date of the Illinois RPS and the IPA's programs and procurements are contained in Section 3.5.1.

Importantly, FEJA transitioned the state's RPS to a streamlined, centralized planning and procurement process, with both RPS targets and available budgets determined on the basis of an electric utility's load for all retail customers with funding collected through a delivery services charge. In other words, following a two-year transition period, separate RPS obligations for ARES ended and an electric utility's total load, whether served by the utility or an ARES, was subject to the RPS charge that funds the renewable resources procurements, thereby eliminating the prior budget uncertainty caused by customers switching supply service to and from ARES.

FEJA additionally included a provision that RECs could not be counted toward RPS targets if they are sourced from a generating unit "whose costs were being recovered through rates regulated by this State or any other state or states on or after January 1, 2017."[108]

3.4. CEJA

Enacted in 2021, the Climate and Equitable Jobs Act (CEJA), Public Act 102-0662, represented, at the time, Illinois' most comprehensive clean energy and decarbonization legislation, building on the foundation laid by the 2016 Future Energy Jobs Act. CEJA codified Illinois' long-term commitment to achieve a 100 percent clean electricity supply by 2050 and accelerated interim RPS targets, while introducing new mechanisms to ensure an equitable transition. The law restructured and expanded renewable procurement programs such as the adjustable block program and Illinois Solar for All, created new market instruments like Carbon Mitigation Credits to preserve non-emitting resources, and established programs for workforce development and community reinvestment. CEJA's reforms align clean energy deployment with affordability and reliability goals, with the aim of integrating climate, equity, and resource adequacy objectives into energy policy. In addition to this section's brief summary of CEJA, further detail on CEJA can be found in Appendix D. Table 3-1 below summarizes CEJA's goals and legislative requirements.

Table 3-1*: CEJA Goals and Legislative Requirements*

CEJA Goals	Description
100% Clean Energy by 2050	Achieve carbon-free electricity and large-scale electrification of all energy systems. "Clean energy" refers to energy generation that is 90% free or greater of carbon dioxide emissions.
Electrification in Transportation	State should have one million electric vehicles (EVs) by 2030.
Solar and Wind Procurement Targets	Procurement of at least 45 million annual RECs from new solar and wind projects by 2030. At least 45% of RECs should come from wind, and 55% from solar.
CEJA Legislative Requirements	**Description**
50% Renewable Portfolio Standard by 2040	Requires REC procurements to cover 40% of load by 2030 and 50% by 2040. RPS requirements apply to Ameren and MidAmerican retail customers within MISO's footprint and ComEd retail customers within PJM's footprint. Large customers have a self-

[108] 20 ILCS 3855/1-75(c)(1)(J).

	supply option that is paired with a reduced RPS charge. The RPS requirements do not apply to municipal utilities, rural cooperatives, and Mount Carmel Public Utility. Budget caps are in place to limit the incremental costs to consumers from procuring renewable energy, but such budget caps also limit utility's ability to meet the RPS targets and goals.
Fossil Fuel Emissions Elimination by 2045	**Privately Owned Generation:** Coal and oil-fired generation must reduce emissions to zero by 2030. Gas fired generation must reduce emissions to zero by 2045, with accelerated emissions reductions based on emissions intensity, location to equity zones or equity investment eligible communities, and heat rates. Annual emissions caps in place based on 2018-2020 levels, with compliance demonstrated through rolling 12-month average emissions. **Publicly Owned Generation:** Coal and oil-fired generation must reduce emissions by 45% by 2035, with an extended deadline of 2038, and to zero by 2045. Gas fired generation must reduce emissions to zero by 2045, with no phaseout schedule. All mandates apply to generating units over 25 MW. Private and publicly owned gas generating facilities can either retire or convert to 100% green hydrogen or similar technology to comply. Exceeding emissions restrictions is allowed in certain instances if the RTO in which the facility participates determines that the facility is necessary to maintain power grid supply and reliability or the facility is a necessary emergency backup to operations.
Utility Electrification Plans	Utilities serving greater than 500,000 customers in the State are required to file a Beneficial Electrification Plan, primarily providing programs that foster electric vehicle adoption, with ICC for programs starting by January 2023.
Nuclear Resource Retention	Authorizes CMC payments through mid-2027 to sustain Illinois' existing nuclear fleet. CEJA authorizes CMC credits for nuclear facilities in PJM. CMC-contracted facilities include Braidwood Units 1 and 2, Byron Units 1 and 2, and Dresden Units 2 and 3.

CEJA includes fossil-plant decarbonization and retirement schedules for coal- and gas-fired units. These timelines establish clear glide paths for retiring or converting substantial portions of Illinois' thermal fleet to decarbonized fuels by 2045, with earlier deadlines for plants near environmental justice communities. While these provisions advance long-term emissions goals, they also introduce significant planning considerations for resource adequacy: as large thermal plants retire or reduce operations, Illinois will rely increasingly on new renewable, storage, demand-side, and transmission resources to maintain sufficient accredited capacity. CEJA includes procedural protections, such as RTO notification requirements, must-run limitations, and reliability-based exceptions, to ensure that retirements occur in coordination with grid needs.

CEJA also restructured and expanded the Adjustable Block Program (rebranded in 2023 to Illinois Shines) and Illinois Solar for All, increasing project size limits, adding new sub-categories, and allocating fixed shares of capacity to key customer groups (e.g., schools, equity-eligible contractors). These changes intend to facilitate faster growth of distributed and community solar, resources that reduce net load, support local resilience, and diversify the state's portfolio of RA-eligible resources. CEJA similarly updated net-metering and DG rebate rules, raising system-size limits to 5 MW, enabling storage co-location, and ensuring full net-metering eligibility for customers who interconnected before 2025. These provisions collectively expanded behind-the-meter and community-scale generation that may reduce peak demand and supplement accredited capacity.

A direct RA implication of CEJA is its introduction of Carbon Mitigation Credits (CMCs) to prevent retirement of economically at-risk nuclear units. Building on FEJA's earlier Zero Emission Credits, CEJA created a five-year CMC program supporting specific PJM-connected nuclear facilities whose continued operation is critical to Illinois' near-term capacity outlook. Nuclear units provide large quantities of firm, accredited capacity; preventing their retirement aimed to avoid shortfalls in northern Illinois while renewable procurement ramps up. CEJA's CMC framework ties payments to market revenues and includes customer-protection caps, creating a cost-controlled mechanism for retaining zero-carbon baseload resources essential for reliability.

Finally, CEJA established multiple programs that indirectly support RA by expanding system flexibility and enabling replacement resources. These include the Coal-to-Solar and Coal-to-Storage programs, which aim to convert retired coal sites into renewable or storage facilities, and DCEO-administered grants supporting more than 185 MW of storage at MISO-region locations. CEJA also required a comprehensive ICC/IPA proceeding on storage deployment and mandated development of a cost-benefit frameworks to evaluate storage's system-level contributions.

3.5. Current Status of CEJA Goals

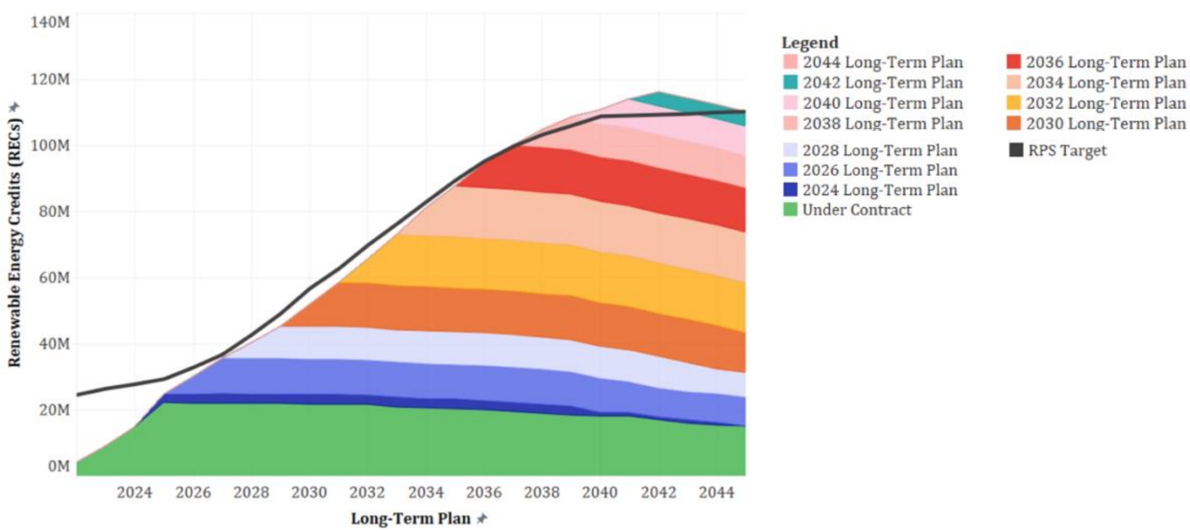
3.5.1. Renewable Energy Resource Development Goals

The Illinois RPS has the goal of matching 25% of retail load with RECs by 2025, with that goal rising to 40% in 2030, and 50% in 2050. As of October 20, 2025, the IPA has procured RECs for the utilities to meet 24% of utility load.[109] Through the remainder of 2025 and the first half of 2026, the IPA will continue to implement the programs and procurements authorized in the 2024 Long-Term Plan. The IPA is currently in the approval process for the 2026 Long-Term Plan which outlines how the IPA will continue to procure RECs for the 2026-2027 and 2027-2028 delivery years.

To meet the Illinois RPS goals, the IPA will need to continue to expand programs and procurements. However, as the IPA has noted over a series of RPS Budget Updates and Long-Term Plan budget analyses,[110] the current structure of funding for the Illinois RPS is insufficient to support the level of procurement needed to meet those goals.

Figure 3-2 shows programs and procurement conducted to date, and those projected to be needed will meet the Illinois RPS.

Figure 3-2: Current and Future Expected REC Procurement Volumes



Source: IPA 2026 Long-Term Renewable Resources Procurement Plan, October 2025.

A challenge for meeting the RPS targets has been the rapid change in future load forecasts over the past year as the impact of the increased electric demand from data centers has been incorporated into planning forecasts. For example, in the 2024 Plan, the 2030 40% RPS goal was forecast to be 46.5 million RECs, while in the 2026 Plan that has risen to 53 million RECs, while the 2040 50% RPS goal had been 60.6 million RECs and is now forecast to be 108 million RECs.

---

[109] IPA Long-Term Renewable Resources Procurement Plan (October 20, 2025), https://ipa.illinois.gov/renewable-resources/long-term-plan.html.

[110] Illinois Power Agency, Updated Renewable Portfolio Standard Budget Forecast (May 12, 2025), https://ipa.illinois.gov/content/dam/soi/en/web/ipa/documents/rpsbudgetupdate51225.pdf.

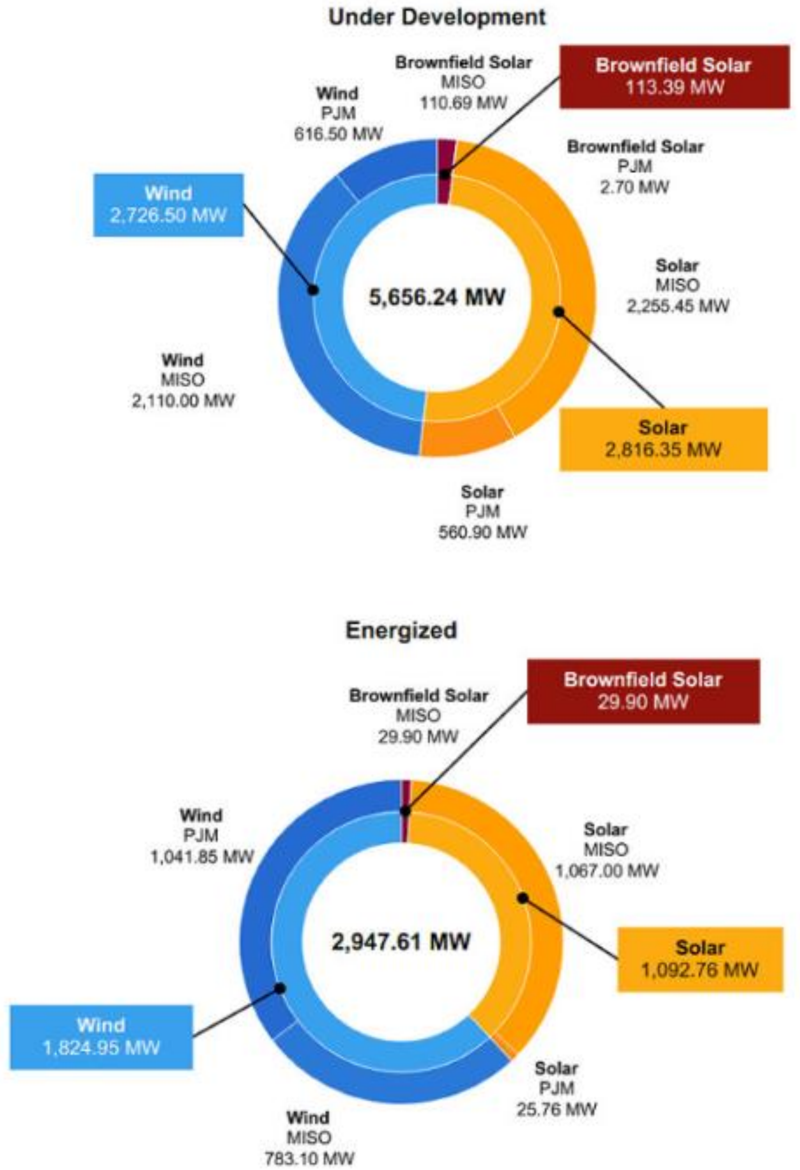
For the context of resource adequacy in Illinois, it should be noted that the RPS is based upon the delivery of RECs in annualized quantities, and that does not necessarily match managing the supply needed to meet load at the critical times needed to maintain reliability. First, while both of the REC tracking systems used for the Illinois RPS, PJM GATS and CleanCounts (formerly known as M-RETS) are in various states of implementing REC tracking that is tied to hourly generation, the Illinois RPS does not currently have that level of granularity. The RECs used to meet the RPS only need to be tied to eligible generation, the hour or day of that generation is not a factor. In addition, the Illinois RPS allows for certain renewable resources in states adjacent to Illinois to qualify. While the IPA has developed a mechanism for applying statutory public interest criteria[111] used to qualify adjacent state renewable resources that factors in the deliverability of power to Illinois, that criteria is broad in scope and only includes loose provisions related to reliability in Illinois, with most of the criteria focused on environmental and emissions considerations.[112] For the Indexed REC procurements conducted by the IPA across 2022 through 2025, 14% of the RECs procured have come from utility-scale wind or solar resources in adjacent states.

As of August 2025, IPA Procurements of utility-scale resources have supported the development of 2,947.61 MW of utility-scale renewable energy resources with an additional 5,656.24 MW of projects under development, as seen in Figure 3-3. While the majority of resources that have been energized have been wind, there is currently slightly more utility-scale solar under development than utility-scale wind.

[111] Adjacent state criteria includes: (1) minimizing sulfur dioxide, nitrogen dioxide, particulate matter and other pollution, (2) increasing fuel and resource diversity, (3) enhanced reliability and resiliency of the electric distribution system, (4) meeting goals to limit carbon dioxide emissions, and (5) contribution to a cleaner and healthier environment.

[112] 20 ILCS 3855/1-75(c)(1)(I). The reliability and resiliency adjacent state criteria defined a threshold based upon proximity of renewable generation resources to Illinois. This criterion does not consider the reliability statistics and considerations defined in the RA Study, IRP, or other similar market and system analysis of such modeling and reports.

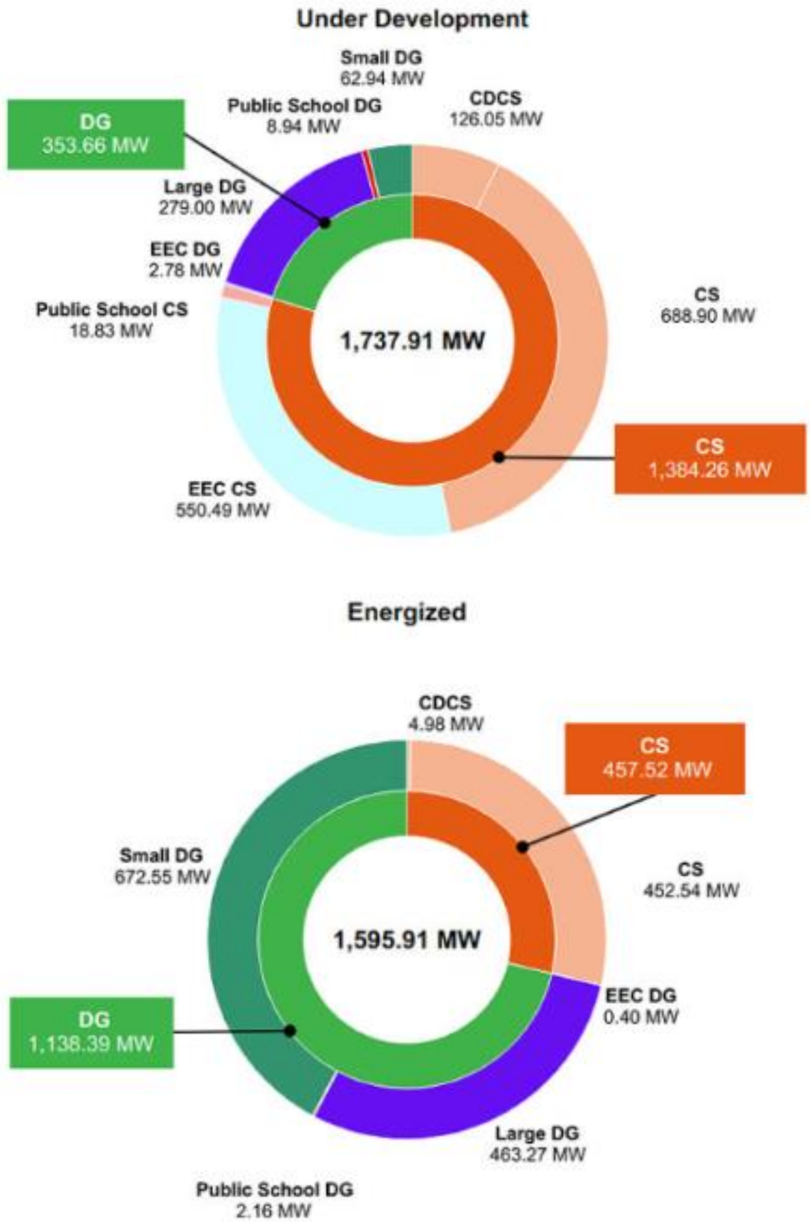
Figure 3-3: IPA Supported Competitive Procurements



Source: Illinois Clean Energy Dashboard, https://cleanenergy.illinois.gov/.

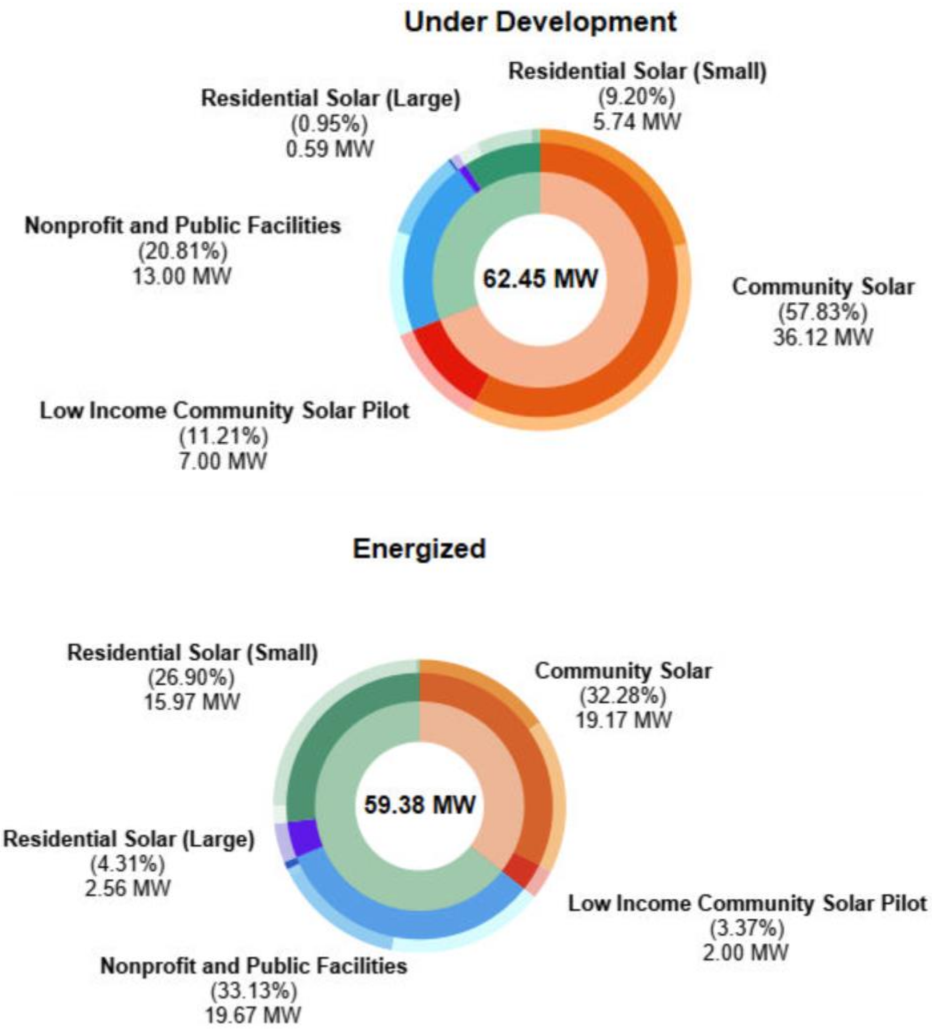
In addition to utility-scale resources, the IPA has supported the development of photovoltaic distributed generation and community solar projects with over 1,600 MW of projects energized and approximately 1,800 MW of projects under development. Figure 3-4 and Figure 3-5 show how Illinois Shines and Illinois Solar for All operate on a continuing basis of taking project applications and these values continue to grow.

Figure 3-4: Illinois Shines Under Development and Energized Resources



Source: Illinois Clean Energy Dashboard, https://cleanenergy.illinois.gov/.

Figure 3-5: Illinois Solar for All Under Development and Energized Project Categorization



Source: Illinois Clean Energy Dashboard, https://cleanenergy.illinois.gov/.

While the Illinois RPS and the programs and procurements conducted by the IPA have been vital to the development of renewable energy resources in Illinois, it should be noted that not all resources in Illinois have been supported by the RPS (especially wind projects). For example, there is 32.9 MW hydroelectric and 55.2 MW of biomass operating in Illinois that have not been supported by RPS incentives. Of the 10,326 MW of wind projects and 6,187 MW of solar in Illinois, the Illinois RPS has heavily supported distributed generation and community solar but has also supported utility scale solar and wind.[113]

[113] IPA FY 24 Annual Report, p. 122 (February 18, 2025): https://ipa.illinois.gov/content/dam/soi/en/web/ipa/documents/20250218-annual-report-fy24-final.pdf.

Developers of renewable energy projects in Illinois would have a variety of reasons for not having the project participate in the RPS and thus be counted to the state's renewable energy goals. The Illinois RPS is based on Illinois utilities buying the RECs from projects and retiring those RECs to ensure that the utility retains the rights to the environmental attributes of the energy that was generated to support the RECs. Some developers have sold the RECs from projects to RPS compliance programs in other states, while other developers have sold the RECs to corporate buyers to help those entities meet their sustainability goals.

3.5.2. Fossil Fuel Phase-Out

Energy sector fossil fuel emissions in Illinois have already been declining over the last decade due to a number of market and regulatory factors. While the first mandated zero emission deadlines under CEJA for large greenhouse gas emitting units are still on the horizon in 2030, CEJA requirements limiting those units to their previous existing emissions also ensures emissions are not growing prior to those dates and that emissions from retiring fossil fuel units cannot simply be shifted to other fossil fuel units in Illinois. This further incentivizes the growth and development of cleaner renewable energy resources in Illinois in addition to the provisions of CEJA aimed directly at that goal.

In the four years since CEJA became law, all of the large greenhouse gas emitting units that are potentially subject to the law have been identified and an inventory of their emissions was compiled by Illinois EPA in the first *Annual Greenhouse Gas Emissions Report for Sources Subject to the Illinois Climate and Equitable Jobs Act - 2024* required under 415 ILCS 5/9.15(n). It is anticipated that units at five of the seven remaining operating coal-fired power plants in Illinois will be retired prior to January 1, 2030.

3.5.3. CO_2e and Co-Pollutant Emissions Reductions

As this is the first quinquennial report required under 415 ILCS 5/9.15(o), and the first annual emissions report required under 9.15(n) was completed in June 2025, it is difficult to quantify the emission reductions directly attributable to CEJA since its passage in 2021. Emissions of GHG and co-pollutants from electric generation have been declining in Illinois for some time, and that trend has continued since the enactment of CEJA. These co-pollutants include sulfur dioxide (SO_2), oxides of nitrogen (NOx), volatile organic material (VOM), and carbon monoxide (CO) from electrical generation.

Below in Table 3-2, shows the CO_2 and co-pollutant emission reductions since CEJA was signed into law in 2021, and the percentage reduction of those pollutants in 2024, the most recent full calendar year that data is available.

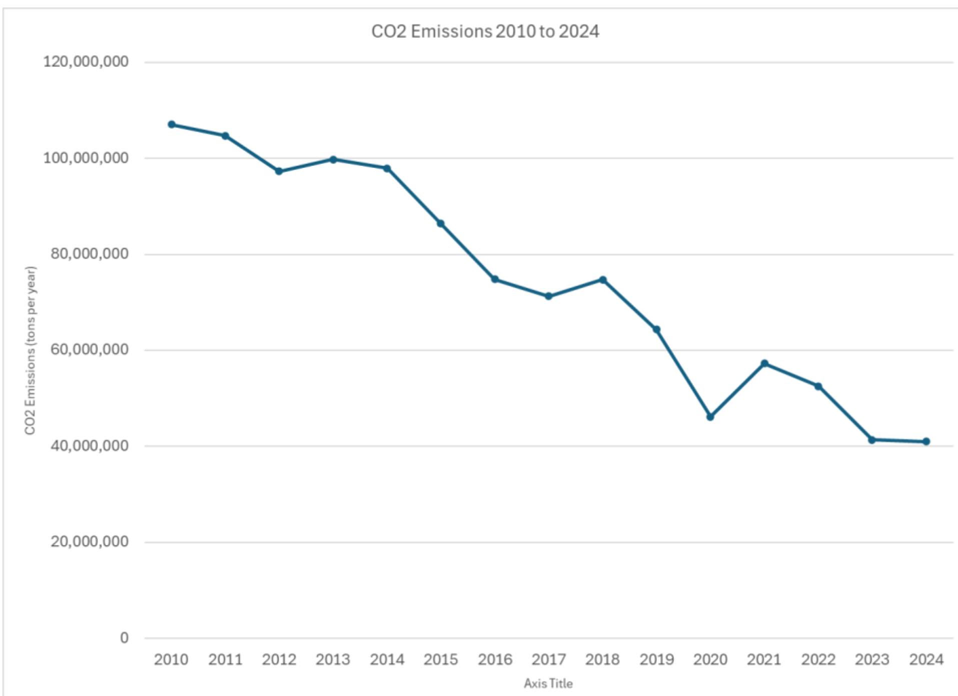
Table 3-2: CO2 and Co-pollutant Emissions Reductions since CEJA

	CO_2	NOx	SO_2
2021	57,315,745	23,195	46,333
2024	41,052,125	11,941	22,874
% Reduction	28.4%	48.5%	50.6%

Note: All data in tons per year. Calculated based on facility reported data submitted to the US EPA.

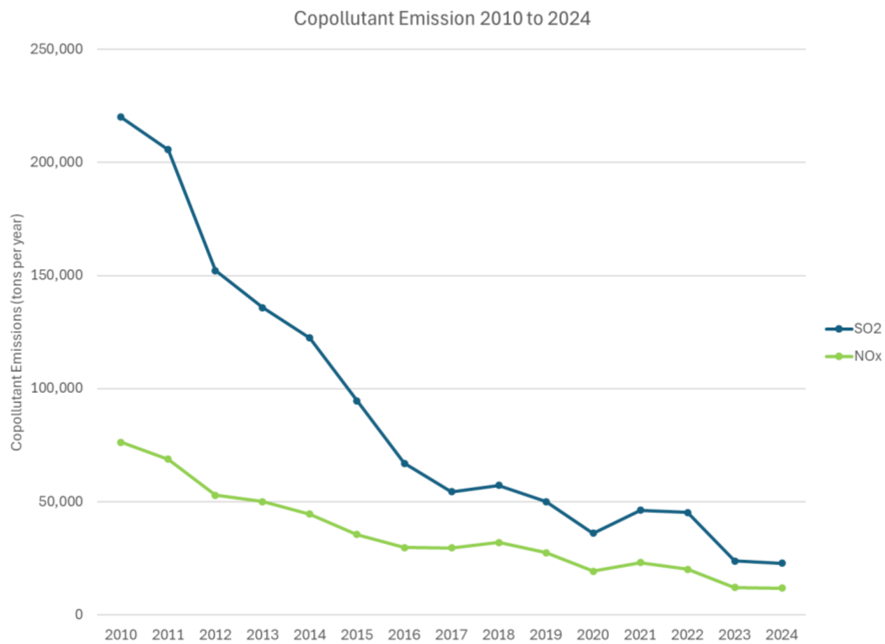
Figure 3-6 and Figure 3-7 illustrate historical emissions reductions from the power sector that will continue and accelerate under CEJA in the near future. The chart shows CO_2 emissions and the most commonly tracked co-pollutants, NOx and SO_2.

Figure 3-6: CO2 Emissions (2010-2024)



Source: USEPA's Clean Air Markets Program Data. https://campd.epa.gov/.

Figure 3-7: Common Co-Pollutant Emissions (2010-2024)



Source: USEPA's Clean Air Markets Program Data. https://campd.epa.gov/.

3.5.4. Green Hydrogen Technology Development & Implementation

Section 9.15(f) of the Environmental Protection Act defines "green hydrogen" as power generation using electrolytic hydrogen created solely from 100% renewable or zero carbon emission energy sources, producing zero emissions. Sections 9.15(i), (j), and (k) allow emissions reductions at large gas-fired and combined heat and power units from "… the use of 100% green hydrogen or other similar technology that is commercially proven to achieve zero carbon emissions."

Subsequent to the effective date of CEJA, the Hydrogen Economy Act created the Hydrogen Economy Task Force to (1) develop a state plan and leverage federal funding for a hydrogen hub; (2) identify opportunities to use hydrogen in energy, transport and industry; (3) assess barriers to deployment, especially in environmental justice communities; and (4) recommend supportive policies.

The Hydrogen Economy Task Force report[114] identified two clean hydrogen incentives as key to project viability: the Federal Section 45V Clean Hydrogen Production Tax Credit and Illinois' state tax incentive for the use of qualifying hydrogen. The report states "these credits can make clean hydrogen projects in Illinois attractive to investors; without them, most

[114] Hydrogen Economy Task Force 2024 Annual Report, Illinois Department of Commerce & Economic Opportunity, Hydrogen Economy Task Force 2024 Annual Report.

clean hydrogen projects are not likely to be viewed as economically feasible."[115] However, Federal Public Law 119-21 (2025) shortened eligibility for the 45V credit to projects beginning construction by December 31, 2027, which the Task Force warns may make many Illinois projects infeasible.[116]

The Midwest Alliance for Clean Hydrogen (MachH2) brings together partners from Illinois, Indiana, Michigan, Missouri and Wisconsin to develop large-scale hydrogen projects. On October 13, 2023, MachH2 announced that it was selected by the US Department of Energy's Office of Clean Energy Demonstrations (OCED) to develop a Regional Clean Hydrogen Hub (H2Hub).[117] MachH2 was awarded up to $1 billion of Federal cost share for Midwest H2Hub, expected to produce tens of thousands of metric tons of hydrogen annually and create about 12,000 direct jobs.[118] Recent reports, however, note uncertainty about sustained federal support.

Despite reductions in federal support, there remains potential to develop clean hydrogen technologies in Illinois. As reported in "An Atlas of Carbon and Hydrogen Hubs for the United State Decarbonization" published by the Great Plains Institute (GPI), there are currently six hydrogen-producing facilities in Illinois, five of which, GPI notes, are generally clustered in an areas of industrial activity and fossil fuel use.[119] Research institutions such as GTI Energy in Des Plaines and the University of Illinois Department of Environmental Engineering are also advancing hydrogen production, storage and infrastructure computability studies.[120,121] As GPI notes, "[c]lusters of hydrogen production and fossil fuel demand can facilitate technology deployment and jumpstart the transition to hydrogen."[122]

Stakeholders are also exploring the use of clean hydrogen for energy production, particularly for large industrial customers, within the Commission's Future of Gas proceeding.[123] This exploration has highlighted work being done in Illinois by entities such as GTI Energy and

---

[115] Ibid.
[116] Federal Public Law 119-21 (2025): https://www.congress.gov/119/plaws/publ21/PLAW-119publ21.pdf.
[117] Midwest Alliance for Clean Hydrogen Press Release (2023): https://machh2.com/oced/.
[118] Gulf Coast and Midwest Hydrogen Hub Announcement: https://www.energy.gov/articles/biden-harris-administration-announces-awards-22-billion-two-regional-clean-hydrogen-hubs.
[119] *Great Plains Institute Carbon and Hydrogen Hubs Atlas (2022)*: https://scripts.betterenergy.org/CarbonCaptureReady/GPI_Carbon_and_Hydrogen_Hubs_Atlas.pdf.
[120] GTI Energy, "World-class R&D and Technology Deployment to Enable the Hydrogen Economy,": https://www.gti.energy/hydrogen-technology-center/.
[121] UIUC, "Hydrogen Storage,": https://isgs.illinois.edu/research/hydrogen-storage/.
[122] *Great Plains Institute Carbon and Hydrogen Hubs Atlas (2022)*: https://scripts.betterenergy.org/CarbonCaptureReady/GPI_Carbon_and_Hydrogen_Hubs_Atlas.pdf.
[123] ICC Future of Gas Proceedings: https://icc.illinois.gov/programs/Future-of-Gas-Workshop.

includes development of pilot projects that could further inform hydrogen usage for Illinois energy generation.[124]

While research and exploration of clean hydrogen technologies continue in Illinois, there are no current independent power producers or electric utilities using hydrogen to fuel utility-scale generation in Illinois. There is also no current infrastructure in Illinois for the transmission of hydrogen to such generation. More work is, therefore, necessary before Illinois is positioned to widely deploy clean hydrogen in the Illinois energy economy.

3.5.5. Economy Wide Decarbonization and Beneficial Electrification Targets

Economy wide decarbonization is key to Illinois' climate goals, including Illinois' 100% clean energy by 2050 goal. It is a multi-faceted endeavor including strategies involving electric vehicle adoption and other transportation measures, building electrification, grid modernization, expansion of renewable energy resources, and promotion of energy efficiency.

Building electrification focuses on replacing natural gas, oil, and wood-based heating and water systems with electric heat pumps and heat pump water heaters to reduce GHG emissions from residential and commercial buildings. To this end, Illinois continues to develop and implement robust building regulations and policies. Improving energy efficiency in buildings and across sectors is also crucial for decarbonization and reducing energy consumption. Illinois has consistently ranked among the top states for LEED-certified buildings per capita.[125]

To advance decarbonization, Illinois has mobilized approximately $1B in green building financing and investments, combining efforts from the Illinois Climate Bank ($250M), utilities ($400M+), federal grants (~$200M), and CEJA-sponsored initiatives ($1M+). Illinois is leveraging funding to support renewable energy and grid modernization, accelerate clean and efficient building adoption, deploy clean transportation and freight measures, support industrial decarbonization, and expand climate-smart agricultural practices.

With respect to the transportation sector, CEJA states, within Section 45 of The Electric Vehicle Act (20 ILCS 627/45) that "Illinois should increase the adoption of electric vehicles in the state to 1,000,000 by 2030." To facilitate achievement of this goal, Section 45 requires Ameren Illinois and ComEd to file Beneficial Electrification Plans with the Commission and to periodically update the plans. The Beneficial Electrification Plans address, among other

[124] GTI Energy, "RNG and Hydrogen – Opportunities for Decarbonization," ICC Future of Gas Proceeding (1/13/2025): https://www.documentcloud.org/documents/25953013-gti-energy-icc-future-of-gas-1-13-25-rng-hydrogen-opportunities-for-decarbonization/.

[125] U.S. Green Building Council's annual Top 10 States for LEED: https://www.usgbc.org/top-10-leed-2024.

things, make-ready investments, incentives for charging equipment and electric vehicles, and enabling rates structures and optimized charging programs to facilitate deployment of electric vehicle adoption throughout the State.

As of October 2025, there are 156,425 electric vehicles registered in the State of Illinois according to the Secretary of State.[126] This is a 370% increase over the number of EV's registered when CEJA passed in September 2021 (33,343 electric vehicles).[127]

Ameren Illinois' initial Beneficial Electrification Plan was filed in June of 2022 and approved through a series of Commission Orders between March 23, 2023 and July 13, 2023.[128] The initial plan covers years 2023–2025.[129] Ameren Illinois' Beneficial Electrification Plan 1 2025 Annual Report contains a summary of its programs and program metrics through 2024.[130] For example, Ameren Illinois' Residential ChargeSmart Program includes bill credits, preferred charging period delivery credits, peak hourly delivery charges, and charger rebates for equity-investment-eligible or low-income customers. Ameren Illinois estimates that through 2024 this program supported 3,254 electric vehicles and 3,379 charging ports.[131] Similarly, Ameren Illinois estimates its Non-Residential ChargeSmart Program supported 13 charging ports through 2024. These and Ameren Illinois' full Beneficial Electrification Plan 1 measures and estimated impacts are summarized in the Annual Report.

ComEd's initial Beneficial Electrification Plan was filed in July of 2022 and approved through a series of Commission Orders between March 2023 and May 2023.[132] The initial plan covers years 2023–2025.[133] ComEd's Beneficial Electrification Plan 1 2024 Annual Report contains a summary of its programs and program metrics through 2024.[134] For example, ComEd estimates that its EV Charger and Installation Sub-Program supported 2,361 charging ports through 2024. It estimated its EV Dealer Network Program to have incented 172 electric vehicles through 2024.

---

[126] Illinois Electric Vehicle Statistics (October 15, 2025): https://www.ilsos.gov/content/dam/departments/vehicles/statistics/electric/2025/electric101525.pdf.

[127] Ibid.

[128] Ameren filed its initial plan in Docket Nos. 22-0431 and 22-0443 (consolidated).

[129] Ameren Illinois, Beneficial Electrification Plan 1 (July 18, 2023): https://www.icc.illinois.gov/docket/P2022-0431/documents/340139/files/593399.pdf.

[130] Ameren Illinois Beneficial Electrification Plan 1 (2025 Annual Report) (April 1, 2025): https://www.icc.illinois.gov/docket/P2022-0431/documents/363430/files/636427.pdf.

[131] Ibid., p. 8.

[132] ComEd filed its initial plan in Docket Nos. 22-0432 and 22-0442 (consolidated).

[133] ComEd Beneficial Electrification Plan 1 (May 2023): https://www.icc.illinois.gov/docket/P2022-0432/documents/338224/files/589765.pdf.

[134] ComEd Beneficial Electrification Plan 1 (2023-2025) 2024 Annual Report: https://www.icc.illinois.gov/docket/P2022-0432/documents/363473/files/636492.pdf.

Recently, both utilities filed and received approval for their second beneficial electrification plans. Both plans modify the initial plans to address learnings to date and will be applicable for the years 2026–2028.[135,136]

While the utility beneficial electrification programs are relatively new, they and other state and federal electric vehicle incentive programs have the potential to increase electricity use in the transportation sector over time.

With respect to building electrification, CEJA amended both Ameren Illinois' and ComEd's electric energy efficiency programs to explicitly allow for the inclusion of electrification measures. In particular, the utilities are permitted to count toward their appliable annual total savings requirements electrification savings up to 5% per year from 2022-2025, up to 10% per year from 2026-2029, and 15% thereafter. In 2024, Ameren Illinois included among its energy efficiency programs, a program providing income qualified customers whole home projects that feature the displacement of propane-fired appliances and mechanicals in favor of high-efficiency electric appliances and mechanicals.[137] ComEd similarly provided within its energy efficiency portfolio a program to convert income-eligible single family and multi-family homes and buildings to all-electric using highly efficient technologies.[138]

As with utility beneficial electrification programs, the programs offered pursuant to the new electrification measures in CEJA are relatively new. They and other state and federal building electrification programs have the potential to increase electricity use in the building sector over time.

3.5.6. Renewable Energy Access Plan

CEJA required the Commission, no later than December 31, 2022, to open an investigation to develop and adopt a renewable energy access plan (REAP) that, at a minimum, does the following:

- Designate renewable energy access plan zones throughout this State in areas in which renewable energy resources and suitable land areas are sufficient for developing generating capacity from renewable energy technologies;

---

[135] ComEd Beneficial Electrification Plan 2 (2026-2028): https://www.icc.illinois.gov/docket/P2024-0484/documents/366102/files/641295.pdf.
[136] Ameren Illinois' Beneficial Electrification Plan 2 (2025): https://www.icc.illinois.gov/docket/P2024-0494/documents/366191/files/641613.pdf.
[137] Ameren Illinois Q4 2024 Energy Efficiency Program Quarterly Report: https://www.ilsag.info/wp-content/uploads/PY2024-Ameren-Illinois-Quarterly-Report-Q4-2024_FINAL.pdf.
[138] ComEd Q4 2024 Energy Efficiency Program Report: https://www.ilsag.info/wp-content/uploads/CY2024-Q4-ComEd-EE-Report.pdf.

- Develop a plan to achieve transmission capacity necessary to deliver the electric output from renewable energy technologies in the renewable energy access plan zones to customers in Illinois and other states in a manner that is most beneficial and cost-effective to customers;
- Use this State's position as an electricity generation and power transmission hub to create new investment in this State's renewable energy resources;
- Consider programs, policies, and electric transmission projects that can be adopted within this State that promote the cost-effective delivery of power from renewable energy resources interconnected to the bulk electric system to meet the renewable portfolio standard targets under subsection (c) of Section 1-75 of the Illinois Power Agency Act;
- Consider proposals to improve regional transmission organizations' regional and interregional system planning processes, especially proposals that reduce costs and emissions, create jobs, and increase State and regional power system reliability to prevent high-cost outages that can endanger lives, and analyze how those proposals would improve reliability and cost-effective delivery of electricity in Illinois and the region;
- Make findings and policy recommendations based on technical and policy analysis regarding locations of renewable energy access plan zones and the transmission system developments needed to cost-effectively achieve the public policy goals identified herein; and
- Present the Commission's conclusions and proposed recommendations based on its analysis and use the findings and policy recommendations to determine actions that the Commission should take.

No later than December 31, 2025, and every other year thereafter, the Commission is to open an investigation to develop and adopt an updated renewable energy access plan that, at a minimum, evaluates the implementation and effectiveness of the renewable energy access plan, recommends improvements to the renewable energy access plan, and provides changes to transmission capacity necessary to deliver electric output from the renewable energy access plan zones.

The first REAP was developed by the ICC and the Brattle Group beginning in 2022. In December 2022, the ICC opened Docket No. 22-0749 to investigate the REAP and adopted a final REAP in 2024. The REAP is an actionable plan for meeting Illinois clean energy goals, which will ultimately culminate in the state using 100% clean energy by 2050. The REAP is an iterative process, with two-year updates to its findings and methodologies. The first REAP identified core five strategic elements: (1) Tracking progress toward Illinois' policy goals, (2) Transitioning to a 100% clean energy mix, (3) Managing land use in renewable development, (4) Effective transmission planning and utilization, and (5) Leveraging regional electricity markets and trade.

The 2024 REAP cast a wide net in terms of its solutions to realize clean energy state policy. Generally, across these elements, the 2024 REAP report's themes highlighted the need for thinking creatively, gathering data, and setting up relationships with other organizations such as the RTOs, utilities, and other state agencies. The first REAP mapped out an institutional foundation for meeting the state's clean energy goals that future REAPs could build upon. In addition, the first REAP did the important work of identifying the first set of potential REAP zones, which can now be used to direct ongoing, refined thinking about transmission planning in Illinois.

The REAP was useful in guiding ICC Staff actions since mid-2024. To highlight a few of those ICC Staff efforts, the ICC staff has worked with both RTOs on interconnection queue reforms. In addition, ICC staff has pressed MISO and PJM to expand their seams work. ICC staff has been involved in market reforms in both RTOs as well. In PJM, ICC Staff was part of a group that explored a clean capacity market in the PJM region. In addition, ICC Staff supported MISO's accreditation reforms and adoption of a sloped demand curve. The REAP has served as an important document in directing staff efforts on specific issues and shaping the particular reforms the ICC seeks in achieving clean energy goals.

Since the adoption of the first REAP, ICC Staff has begun to develop the next REAP. The second REAP docket will open in December 2025, with a final REAP likely adopted by the commission by the end of 2026. Progress on the second REAP began in 2nd quarter of 2025. The ICC secured the services of E3 as their consultant for several forthcoming REAP cycles. E3 will specifically aid with transmission modeling issues. The ICC also brought on Viridis and 2IM to assist with the current REAP, particularly with community outreach efforts. In the first half of 2025, ICC Staff and E3 have made meaningful progress on the second REAP cycle. E3's focus, as directed by CEJA, will be on updating the REAP zones. E3 will be relying on their methodology which will begin with the REAP zones and then identify generation and transmission solutions needs to meet CEJA goals. This analysis will result in near-term actions that inform later transmission analysis. This transmission analysis will then guide the future REAP zones and begin the analysis process again. In pursuit of that goal, E3 has gathered data from the RTOs and utilities about the transmission system. Currently, as part of this REAP cycle, E3 and ICC Staff are requesting both RTOs to provide headroom data where not already available. E3 is also gathering other spatial data about Illinois and has recently geocoded REAP zones with support from the DOE. E3 is using this information to develop with ICC Staff an initial transmission plan that advances the state's clean energy goals. During the second REAP cycle, ICC Staff and its consultants hosted four workshops, a technical workgroup meeting, and a community education session. The second REAP is building directly from the foundation set with the initial REAP while pushing methods and policy recommendations in new directions.

3.6. Summary

Illinois' path toward a carbon-free grid under CEJA introduces structural changes that directly influence the state's resource adequacy outlook. The scheduled retirement of fossil generation, the evolving composition of renewable and storage capacity, and accelerating load growth together point toward a period of tightening capacity margins.

The following chapters evaluate these dynamics quantitatively. This report examines how Illinois' capacity needs, renewable additions, and market dependencies may interact over time, and what implications they carry for ensuring reliable, affordable, and clean electricity service consistent with the state's policy goals.

4. State of Resource Adequacy

The principal objective of this report is to assess resource adequacy for Illinois consumers over an appropriate planning horizon. The development of new electric supply resources typically takes five to seven years,[139] with certain kinds of resources and critical grid infrastructure expected to require even longer timelines, including transmission, which can often take ten years or more to develop.[140] Accordingly, this report includes an assessment of reliability needs in MISO, PJM, and Illinois from today (late 2025) through 2045 to inform how resource adequacy needs may change as the load and generation mix evolves in these regions. Many actions, which are taken today or could be regarding resource development, retirement, or extension, have longer term impacts on reliability, costs, and the landscape for future actions. Therefore, it is important to assess near-term resource adequacy needs within a longer time horizon to inform decision-making.

Assessing resource adequacy risk requires answering three principal questions:

1. What is the expected reliability requirement over the resource adequacy evaluation period?
2. How will the projected mix of existing and future resources contribute to the expected reliability requirement?
3. What are the risks to achieving resource adequacy balance in the future?

This chapter focuses on the resource adequacy risk in the near-term, specifically over the next ten years from 2026 through 2035. The next chapter of this report assesses how resource adequacy needs may evolve for Illinois within the context of the broader regional markets over a longer time horizon from 2030 through 2045.

To determine whether the current electric systems in Illinois are meeting expected reliability standards, E3 anchors its resource adequacy assessment to the latest capacity market auction outcomes from MISO and PJM.

To assess resource adequacy in the future and the risks of meeting reliability standards, E3 performed two related analyses: resource adequacy balance projections via a load and resource assessment for the near term and portfolio analysis using loss of load probability

---

[139] "Queued Up: 2024 Edition — Characteristics of Power Plants Seeking Transmission Interconnection As of the End of 2023," Lawrence Berkeley National Laboratory (April 2024): https://emp.lbl.gov/publications/queued-2024-edition-characteristics

[140] "Power Delayed: Economic Effects of Electricity Transmission and Generation Development Delays," Resources for the Future, Working Paper No. 25-14 (May 2025): https://www.rff.org/publications/working-papers/power-delayed-economic-effects-of-electricity-transmission-and-generation-development-delays

and capacity expansion modeling for the longer term. E3's load and resource projections illustrate the net effect of future load growth, planned retirements, and generator additions on the resource adequacy balance from the system today through 2035. We assess the risk of achieving near term resource adequacy targets based on the uncertainties and risk factors governing load growth, new resource development, and resource retirements.

E3's portfolio analysis addresses the longer-term resource adequacy assessment from 2030 through 2045. The portfolio analysis involves simulating forward-looking resource need and effective load carrying capabilities (ELCCs) of existing and future resources in MISO and PJM and then modeling various resource portfolios that meet the future system's resource adequacy needs under different scenarios. That portfolio analysis is presented in the next chapter (Chapter 5). We assess the risks of achieving long term resource adequacy by examining the feasibility and potential challenges of developing one or more resource adequate portfolios under current regulatory, policy, and market structures.

4.1. Resource Adequacy Today in PJM and MISO

The capacity market auctions run by PJM and MISO are forward-looking resource adequacy assessments of the supply and demand balances in each region, representing the best available data on near-term reliability needs and capacity contributions by all resources in the current system. The latest auctions covered the 2026/2027 delivery year in PJM and the 2025/2026 delivery year for MISO.

4.1.1. PJM Auction Results

The latest PJM Base Residual Auction (BRA) for the 2026/2027 delivery year cleared just below the RTO-wide resource adequacy target, but the RTO as a whole cleared just above the reliability target when including loads and resources that opted out of the BRA under the Fixed Resource Requirement (FRR) option.[141] In total, PJM secured 146,243.8 MW (unforced capacity, or UCAP) across the RTO compared to a reliability target of 146,105 MW (UCAP), representing a surplus of only 138.8 MW (or 0.1% of the total requirement). These results indicate that the PJM system today is almost exactly meeting its reliability standard of a one day in ten years loss-of-load event.

[141] The FRR allows load serving entities within PJM to opt out of the capacity auction provided that these loads meet their share of the total reliability requirements with a combination of owned and contracted resources. In the 2026/2027 auction, FRR participants contributed a slight surplus in total capacity, which allowed the entire RTO to move from a slight deficit of capacity in the BRA to a slight surplus overall.

Without the FRR commitments, the BRA itself cleared at 134,310.8 MW, equivalent to a reserve margin of 18.9% compared to a reliability target of 19.1% (0.2% short).[142] With this shortfall, the 2026/2027 auction also set a new price record at $329.17 per MW-day (UCAP)[143]—the highest RTO-wide capacity price since the auctions started in 2007/2008.[144] In PJM's own analysis, the auction would have cleared at an even higher price of $388.57 per MW-day (UCAP)[145] if not for the price cap of $329.17 implemented by PJM in response to a complaint filed by Pennsylvania Governor Josh Shapiro with FERC.[146]

The 2026/2027 auction follows a continuing trend of higher prices and tightening resource adequacy balances since 2024. Prices rose from a low of $28.92 per MW-day in 2024/2025 to $269.92 per MW-day in 2025/2026.[147] In the 2026/2027 auction, PJM's reliability requirement increased by 5,446 MW relative to 2025/2026, driven in large part by data center loads, while total cleared capacity only increased by 426 MW.[148] Table 4-1 shows the results for the 2026/2027 delivery year BRA, and Figure 4-1 shows the resulting resource mix.

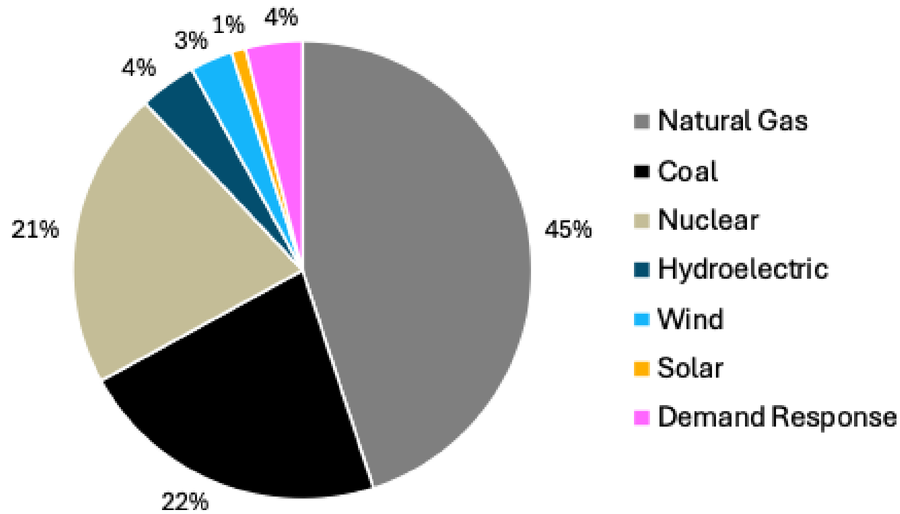
Table 4-1: PJM Capacity Auction Results for 2026/2027

Category	2026/2027 Result
Capacity Balance	PJM secured 134,311 MW of unforced capacity (UCAP) through the auction, plus 11,933 via Fixed Resource Requirement (FRR) commitments, totaling 146,244 MW. Total resources exceeded the RTO-wide target of 146,105 MW by 138.8 MW (0.1% of the total).
Reserve Margin	The BRA cleared at 18.9%, slightly below the 19.1% target.
Clearing Price	PJM-wide capacity prices hit the FERC-approved cap of $329.17/MW-day in all market zones, a 22% increase from the previous year's RTO price of $269.92/MW-day.
Total Cost	The total illustrative auction cost reached $16.1 billion, up from $14.7 billion in the previous year. Auction cost represents cleared capacity (MW) times the clearing price, but it does not account for loads which have owned or contracted resources settled bilaterally outside of the auction.

[142] "2026/2027 Base Residual Auction Report," PJM, page 3 (July 22, 2025): https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2026-2027/2026-2027-bra-report.pdf.
[143] "2026/2027 Base Residual Auction Report," page 5.
[144] "2024/2025 RPM Base Residual Auction Results," page 5, PJM: https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2024-2025/2024-2025-base-residual-auction-report.ashx.
[145] "2026/2027 Base Residual Auction Report," page 16.
[146] "Complaint of Governor Josh Shapiro and the Commonwealth of Pennsylvania," FERC (December 30, 2024): gov. shapiro and commonwealth of pa complaint(119760108).pdf.
[147] "2026/2027 Base Residual Auction Report," page 5.
[148] "2026/2027 Base Residual Auction Report," pages 3 and 11.

Source: "2026/2027 Base Residual Auction Report," PJM, July 22, 2025, https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2026-2027/2026-2027-bra-report.pdf.

Figure 4-1: PJM Accredited Capacity Resource Mix for 2026/2027



4.1.1.1. PJM Auction Results for Illinois

The ComEd zone, which represents the portion of Illinois located within PJM, cleared at the same maximum price of $329.17/MW-day (UCAP) as the rest of the RTO (and all other zones in the 2026/2027 auction)—indicating that the ComEd zone faces the same resource adequacy balance as the broader region and is not currently any more constrained than the market as a whole.

4.1.2. MISO Auction Results

MISO's 2025-2026 Planning Resource Auction (PRA) cleared with 137,559.3 MW of supply for the summer season, yielding a 2,345.9 MW surplus (1.7%) above the system target of 135,213.4 MW.[149] Most of the supply (97,811.7 MW) was contributed by self-scheduling resources, with 19,947 MW committed by participants in the FRAP and 19,800.6 MW clearing the auction based on economic bids.[150] MISO is a summer-peaking system (like PJM) which typically defines the constrained period; as such, all other seasons for 2025/2026 cleared with larger surpluses relative to the reliability targets. The auction results indicate that MISO is resource adequate today, but there is a clear trend of decreasing capacity surplus over the past three auctions, indicating a tightening of the RA market.

---

[149] "Planning Resource Auction: Results for Planning Year 2025-26," page 18, MISO (April 2025): https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250529_Corrections694160.pdf.

[150] "Planning Resource Auction: Results for Planning Year 2025-26," page 18.

The 2025/2026 PRA set a record for summer prices in the history of the auction since 2015/2016, clearing at $666.50 per MW-day—22 times higher than the summer 2024/2025 price of $30/MW-day and 66 times higher than the summer of 2023/2024 ($10/MW-day).[151,152] The summer capacity surplus has been falling from 6.5 GW (2023) to 4.6 GW (2024) to 2.3 GW (2025) due to a combination of coal and gas generator retirements or suspensions, load growth, and updates to resource capacity accreditation. From Summer 2024 to 2025, offered accredited capacity decreased from 140.7 GW to 137.8 GW as 5.1 GW of new resources were offset by 3.3 GW of thermal retirements, a 3.7 GW decline in total accreditation, and a 0.9 GW decline in external resources offered.[153] The 2025/2026 PRA also applied MISO's Reliability-Based Demand Curve (RBDC) for the first time, which provided a stronger price signal than the previous vertical demand curve as the system's capacity surpluses fall closer to the reliability target.

The results of the MISO PRA for the 2025/2026 planning year are summarized in Table 4-2 and the capacity resource mix for the summer season is presented in Figure 4-2.

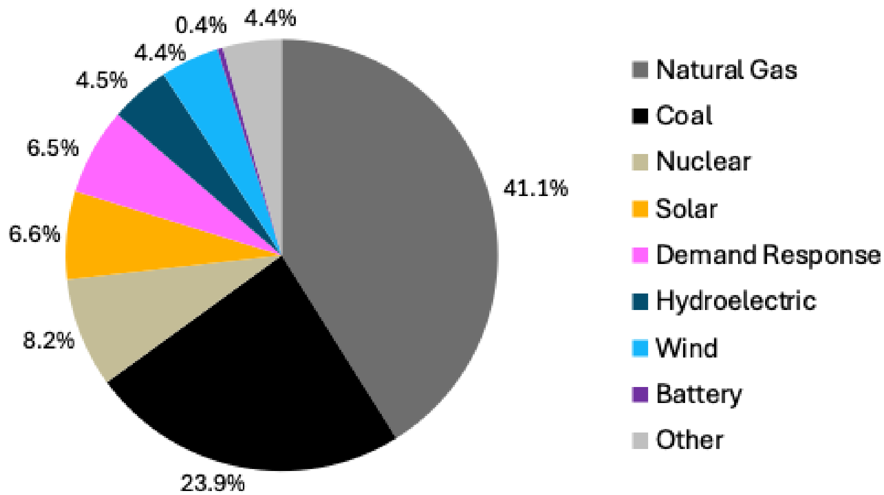
Table 4-2*: MISO Capacity Auction Results for 2025/2026*

Category	2025/2026 Result
Capacity Balance	137,559.3 MW cleared for the summer season, including 19,947 MW contributed by FRAP participants. Total resources exceeded the RTO-wide target of 135,213.4 MW by 2,345.9 MW (1.7% of the total).
Reserve Margins	Summer: 9.8% cleared vs. 7.9% target Fall: 17.5% cleared vs. 14.9% target Winter: 24.5% cleared vs. 18.4% target Spring: 26.8% cleared vs. 25.3% target
Clearing Prices	Annual Average: $217/MW-day (North/Central) and $212/MW-day (South) Summer: $666.50/MW-day across all zones Fall: $91.60/MW-day (North/Central) and $71.09/MW-day (South) Winter: $33.20/MW-day across all zones Spring: $69.88/MW-day across all zones
Total Cost	The total illustrative auction cost reached $10.5 billion across all zones and seasons. Auction cost represents cleared capacity (MW) times the clearing price, but it does not account for loads which have owned or contracted resources settled bilaterally outside of the auction.

Note: Source: "Planning Resource Auction: Results for Planning Year 2025-26," MISO, April 2025, https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250529_Corrections694160.pdf.

151 "Planning Resource Auction: Results for Planning Year 2025-26," page 27.
152 Note: MISO implemented a methodological change starting in the 2023/24 Planning Year, moving from an annual capacity price to seasonal pricing.
153 "Planning Resource Auction: Results for Planning Year 2025-26," page 6.

Figure 4-2: MISO Accredited Capacity Resource Mix for 2025/2026



4.1.2.1. MISO Auction Results for Illinois

Illinois is served by three of MISO's load resource zones: LRZ 4 (Ameren and Mt. Carmel), LRZ 1 (Jo Carroll Energy Cooperative) and LRZ 3 (Mid-American). These Illinois zones are part of the larger North/Central region of MISO which includes LRZs 1-7. All North/Central region zones cleared at the same price across all four seasons of the 2025/2026 auction. These results indicate that the Illinois portions of MISO are at a similar resource adequacy balance as the rest of MISO North/Central and are not currently constrained by transmission for meeting zonal reliability requirements.

4.1.3. Conclusions on recent RTO Capacity Auctions

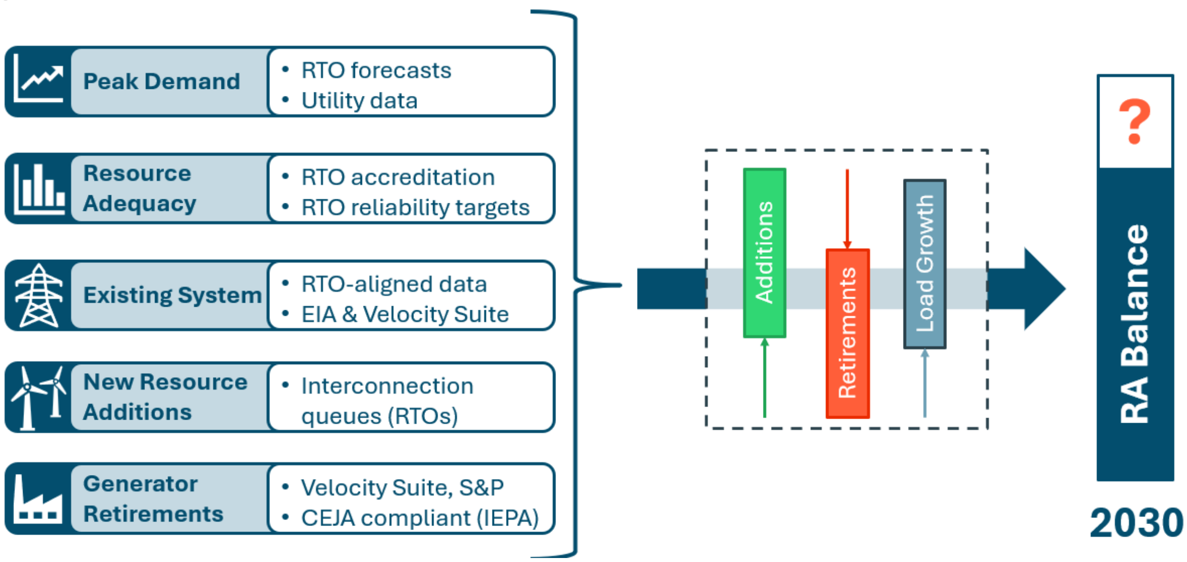
Both PJM and MISO (and by extension, Illinois zones) are resource adequate today to meet the RTOs' reliability standards of a loss of load event occurring at most one day in ten years. However, resource adequacy margins in both regions are becoming increasingly constrained, due to load growth, thermal generator retirements, and updates to resource adequacy market structure, including the resource accreditations for renewable, storage, and thermal resources. Data centers are the primary driver of load growth in the latest forecasts from utilities and the RTOs, with load growth projections at levels well above those observed in either market over the past twenty years. Combined with an aging fleet of coal and gas generators, this load growth is poised to put immense pressure on the reliability of both systems. The latest auctions in PJM and MISO each set record high capacity prices, providing an incentive for new resource development and the retention of existing generation as reliability margins become tight. While this price signal is designed to support resources needed for system reliability, it also increases costs to consumers.

4.2. Resource Adequacy Balance Projections (2026-2035)

Building from the latest capacity auction results and current system loads and resources, E3 projected resource adequacy balances for PJM, MISO, and relevant Illinois zones from 2026 through 2035. These projections evaluate whether expected supply will be sufficient to meet projected demand and to identify major drivers of risk and uncertainty in the near term. The model begins with peak load forecasts from PJM, MISO, MISO LRZ 4 (the core Illinois zone of MISO, primarily comprised of Ameren Illinois), and the ComEd zone of PJM for each year, and builds a supply stack that includes the existing resource fleet, adjusted for announced retirements and new capacity that is projected to be online based on interconnection queue data.

To estimate the reliability contribution of each resource, the model applies resource accreditation assumptions from the RTOs by technology type based on the latest capacity accreditations available. While resource accreditations utilized available RTO data for the near-term projections, E3 performed detailed loss of load analysis to estimate how ELCCs may change over the longer term, and these results are presented in the next chapter as part of E3's portfolio modeling analysis. The load-resource balance projections quantify expected surpluses or shortfalls in the near term driven by major assumptions on load growth, resource additions, and retirements, and these assumptions in turn inform scenario development and baseline data for the portfolio analysis of various resource solutions to the evolving resource adequacy needs in both markets (presented in the next chapter).

Figure 4-3: Load and Resource Balance Framework



The resource adequacy balance model includes four regions of analysis: PJM and MISO at the RTO level, and the ComEd zone (within PJM) and MISO LRZ 4 (within MISO) at the Illinois zonal level. This structure enables the analysis to account for both regional conditions and localized constraints, recognizing that Illinois' ability to maintain adequacy depends on both in-state resources and broader system conditions within each RTO.

4.2.1. Load Forecasts

4.2.1.1. PJM

The PJM load forecast used in this study is based on the 2025 PJM Long-Term Load Forecast Report[154] with targeted adjustments to better reflect long-term uncertainty. In the near term (2026–2030), the peak load forecast aligns with PJM's projections, which account for residential, commercial, and industrial growth trends, as well as rapid growth in data center loads. However, beyond 2030, this assessment assumes a more moderate pace of data center growth compared to PJM's forecast. It is assumed in our modeling that data center growth declines from the 2026-2030 annual average growth rate of 14% per year to 1% per year by 2040.

This trajectory for new data center loads is anchored to an assumption that the rapid growth of data centers is driven by new services—particularly artificial intelligence products—which will reach a 'saturation point' over the next ten years and then grow at a stable rate aligned with long term population growth. This assumption is informed by facility-level data on announced and under-construction projects from sources such as DataCenterMap[155] CBRE,[156] Baxtel,[157] JLL,[158] and EPRI[159], with long-term trends aligned to historical deceleration rates seen in earlier development cycles. Justification for these adjustments are described further in section 5.3.1.3 and Appendix F. These adjustments support a more balanced outlook on demand while maintaining the assumption of significant near-term growth.

As a result, PJM's annual summer peak demand, illustrated in Figure 4-4 below, is projected to increase 16% by 2030 and 29% by 2035, relative to 2026 levels. While data centers are modeled to have relatively steady operations across the days and seasons, they are assumed to require more electricity for cooling in the summer based on historical data.

---

[154] 2025 PJM Long-Term Load Forecast Report (January 24, 2025): https://www.pjm.com/-/media/DotCom/library/reports-notices/load-forecast/2025-load-report.pdf.
[155] Data Center Map: https://www.datacentermap.com/.
[156] CBRE: North America Data Center Trends H1 2025: https://www.cbre.com/insights/reports/north-america-data-center-trends-h1-2025.
[157] Baxtel: https://baxtel.com/data-center/united-states.
[158] JLL: North American Data Center Report Midyear 2025: https://www.jll.com/en-us/insights/market-dynamics/north-america-data-centers.
[159] EPRI: Analyzing Artificial Intelligence and Data Center Energy Consumption: https://www.epri.com/research/products/3002028905.

Accordingly, PJM is forecasted to remain a summer peaking system throughout the study period.

Figure 4-4: PJM Peak Load Forecast

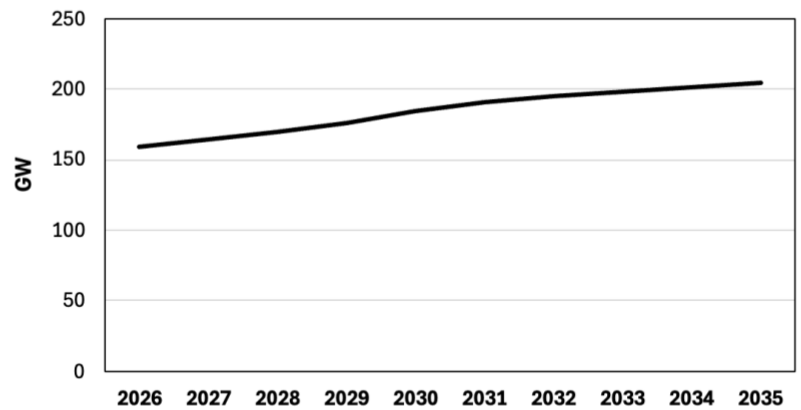
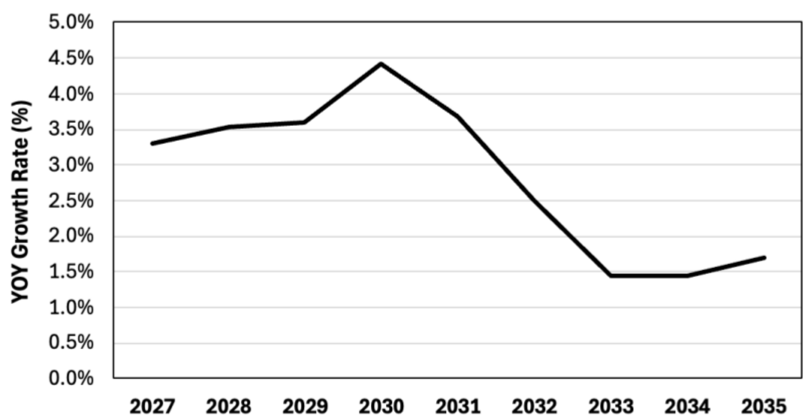


Figure 4-5: PJM Peak Load Annual Growth Rate



4.2.1.2. MISO

The MISO peak load forecast used in this study is based on the Current Trajectory scenario in MISO's 2024-2025 Long-Term Load Forecast Report.[160] MISO's baseline already incorporates adjustments for data center load realization, and this study uses MISO's data center load estimates without further adjustments. However, demand associated with green hydrogen production and Inflation Reduction Act–driven industrial growth explicitly split out in the forecast is excluded due to uncertainty around federal policy support and project viability. The resulting forecast shown in Figure 4-6 reflects steady peak load growth

[160] MISO Medium and Long-Term Load Forecast (December 18, 2024): https://www.misoenergy.org/events/2024/medium-and-long-term-load-forecast---december-18-2024/.

with a slightly higher near-term growth rate, largely driven by data center expansion, which is projected to increase from approximately 3% of total load in 2026 to 13% by 2035.

Based on this trajectory, MISO's summer peak demand is forecasted to grow by 8% by 2030 and 18% by 2035, relative to 2026 levels. As in PJM, data centers are modeled with relatively consistent usage patterns, with moderate seasonal variation due to slightly higher summer cooling requirements. MISO is expected to remain summer-peaking throughout the study horizon.

Figure 4-6: MISO Peak Load Forecast

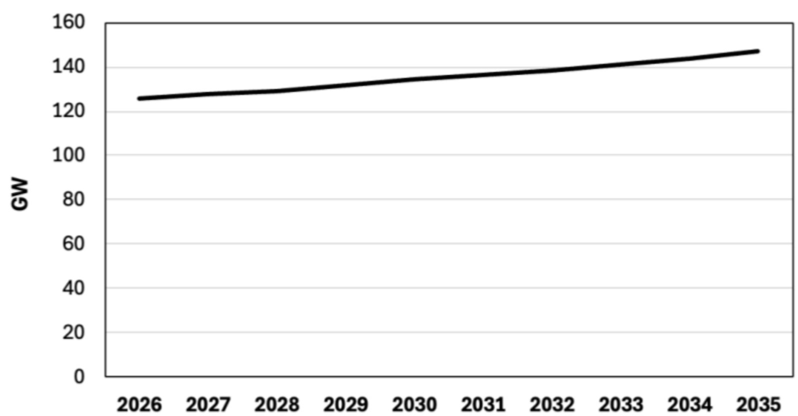
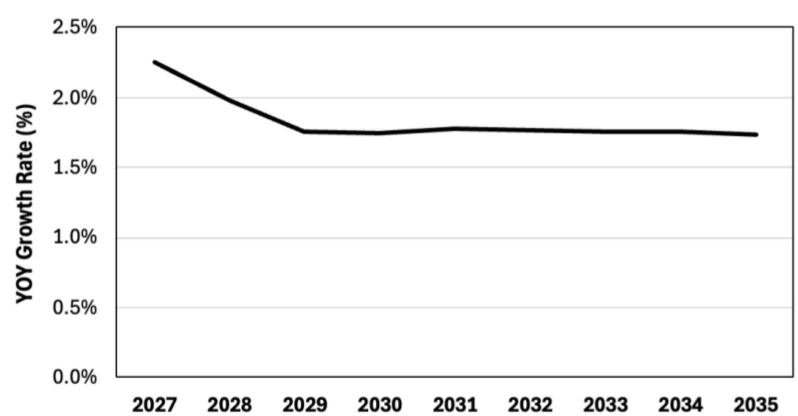


Figure 4-7: MISO Peak Load Annual Growth Rate



4.2.1.3. ComEd

The ComEd peak load forecast used in this analysis is consistent with the values published in the IPA's 2026 Long-Term Plan.[161] ComEd projects significant load growth from data

[161] IPA Long-Term Renewable Resources Procurement Plan (October 20, 2025): https://ipa.illinois.gov/renewable-resources/long-term-plan.html.

centers within its service territory, ramping up in 2030, which is a key driver of rising peak demand in the PJM ComEd zone. To account for the full zone, including load from municipal utilities and electric cooperatives not served by ComEd, PJM's 2025 load forecast is used to supplement the ComEd forecast and represent the total zonal load more comprehensively.

Based on these inputs, the ComEd zone's summer peak demand shown in Figure 4-8 is projected to grow by approximately 5% by 2030 and 36% by 2035, relative to 2026 levels. These increases are largely driven by data center expansion and other electrification trends. As with the broader PJM system, the ComEd zone is expected to remain summer-peaking throughout the forecast horizon, with data center loads modeled as relatively consistent across seasons, but slightly higher in summer months due to cooling requirements.

Figure 4-8: ComEd Zone Peak Load Forecast

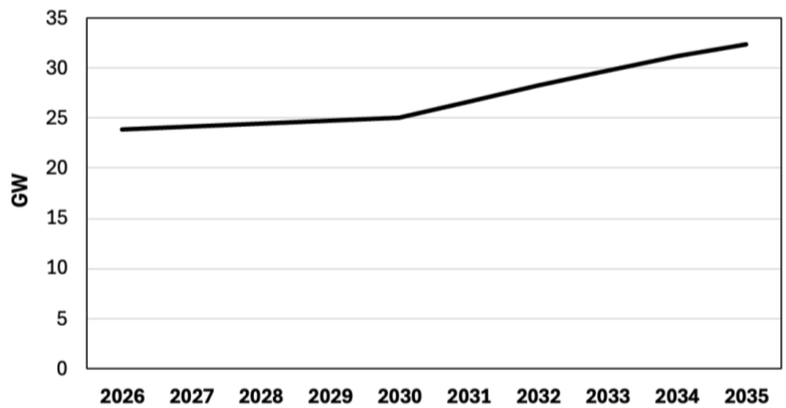
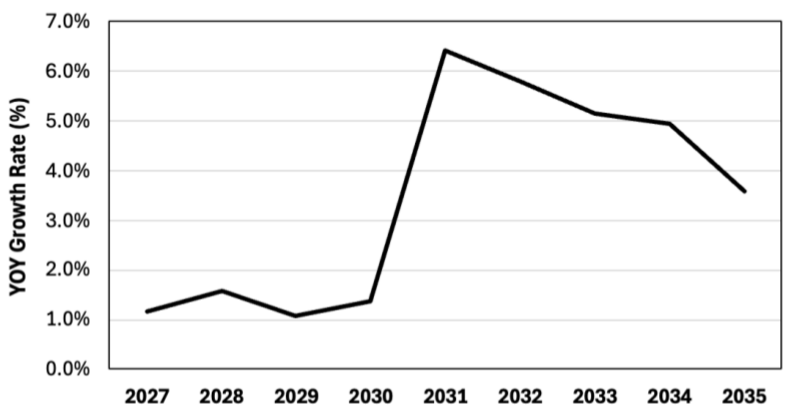


Figure 4-9: ComEd Zone Peak Load Annual Growth Rate



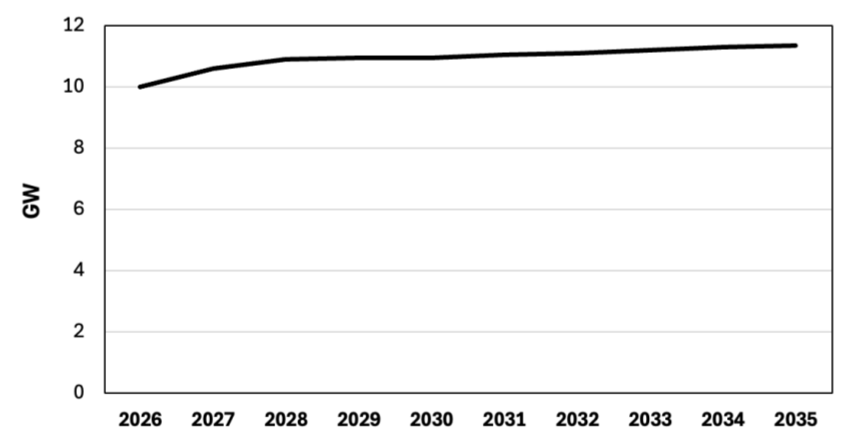
4.2.1.4. MISO LRZ 4

The MISO LRZ 4 forecast is based primarily on Ameren Illinois' service territory, which accounts for the majority of the zone's load. Ameren's load forecast in this analysis is consistent with the projections in the IPA Long-Term Plan[162], which anticipate notable near-term load growth, especially from data centers and large commercial and industrial development. To reflect total load across the zone, forecasts were supplemented with data for municipal utilities and electric cooperatives within LRZ 4, using MISO's long-term forecasting framework.

Under these assumptions, MISO LRZ 4 peak demand, illustrated in Figure 4-10, is projected to increase by approximately 10% by 2030 and 14% by 2035, relative to 2026 levels. These trends follow the broader MISO trajectory, and LRZ 4 is expected to remain a summer-peaking zone throughout the study period. No significant shifts in seasonal peak patterns are anticipated within the modeling horizon.

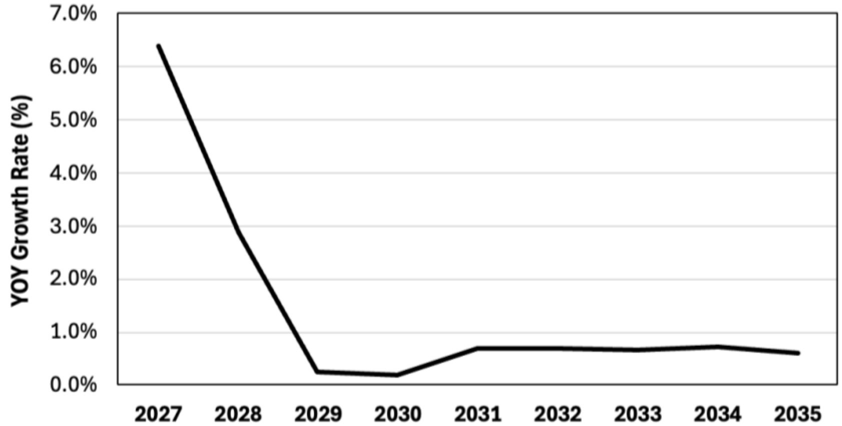
A portion of Illinois load also falls within MISO LRZs 1 and 3, which includes MidAmerican Energy's service territory and Jo Carroll Energy Cooperative's service territory in western Illinois. For this portion of the state, the load forecast is also consistent with the 2026 IPA Long-Term Plan and aligns with MISO's broader Current Trajectory forecast. Because MISO LRZs 1 and 3 includes a multi-state footprint and represents a smaller share of Illinois load, detailed analysis of this sub-region is not presented in the zonal resource adequacy results, but its contribution is captured in the system-wide MISO analysis.

Figure 4-10: MISO LRZ 4 Peak Load Forecast



[162] IPA Long-Term Renewable Resources Procurement Plan (October 20, 2025): https://ipa.illinois.gov/renewable-resources/long-term-plan.html.

Figure 4-11: MISO LRZ 4 Peak Load Annual Growth Rate



4.2.2. Generation Capacity Assumptions

The representation of installed generation capacity serves as the first key supply-side input in the resource adequacy balance. This subsection outlines assumptions for both existing resources and new resources projected to be online across the study horizon in PJM, MISO, as well as the Illinois zones of ComEd and LRZ 4. Existing resources reflect the current generation fleet, while new resources reflect expected additions drawn from interconnection queue data based on development status and commercial readiness. Capacity values are organized by technology type and planning zone.

4.2.2.1. Existing Resources

Installed generation capacity in 2026 serves as the starting point for the resource adequacy balance in both PJM and MISO. To develop a complete and accurate representation of the existing resource fleet, E3 uses plant-level data from the Energy Exemplar PLEXOS database, which is built on data from the U.S. Energy Information Administration.[163] To ensure accuracy and completeness, additional data from Hitachi Energy's Velocity Suite, S&P Global Capital IQ, and supplementary research by E3 are incorporated to refine plant attributes, ownership, and operational status. For additional details, please refer to Appendix F.

In PJM, total installed capacity in 2026 is predominantly natural gas generation, which accounts for nearly 60% of the fleet or 98 GW. The remaining thermal fleet is evenly split between coal (35 GW) and nuclear (34 GW). PJM also includes a growing base of renewable

[163] Form EIA-923 detailed data: https://www.eia.gov/electricity/data/eia923/.

and non-thermal resources: 12 GW of wind, 19 GW of solar, and other miscellaneous resource types comprising roughly 70 GW of additional capacity.

In MISO, the resource mix differs significantly. While natural gas generation remains the largest resource at 82 GW, the system includes more coal (41 GW) and less nuclear capacity (12 GW) compared to PJM. MISO also features more wind (34 GW) and solar (26 GW) than PJM, reflecting historical development patterns, regional siting preferences, renewable resource potential, and transmission access constraints.

Anticipated retirements between 2026 and 2035 reflect both economic and policy-driven trends, particularly for the aging coal fleet in PJM and MISO. In PJM, coal retirements are projected to be significant over the coming decade. Installed coal capacity is projected to decline from 35 GW in 2026 to 20 GW by 2030, and further to 17 GW by 2035. These retirements reflect the combination of plant age and environmental policy pressures at the state and federal levels. Natural gas retirements are more modest, with gas capacity falling from 98 GW in 2026 to 92 GW by 2035, reflecting the fact that gas generator fleet is younger than the coal fleet and tends to have more favorable economics.

MISO follows a similar trend, with installed coal capacity declining from 41 GW in 2026 to 32 GW by 2030, and 23 GW by 2035. As in PJM, these retirements are largely concentrated among older units facing unfavorable economics, environmental compliance costs, or both. Gas retirements in MISO are projected to reduce total capacity from 82 GW to 71 GW over the same period. Although less numerous than coal, these gas retirements contribute to tightening reserve margins in both RTOs.

Figure 4-12 and Figure 4-13 below show the trajectory of existing resources for each RTO across the assessment horizon.

Figure 4-12: Existing Generation Resources Nameplate Capacity in PJM

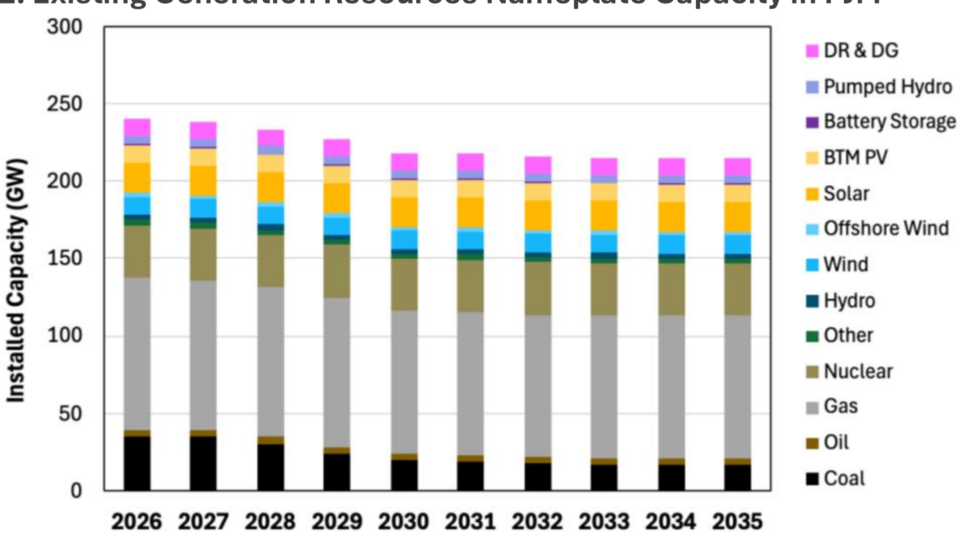
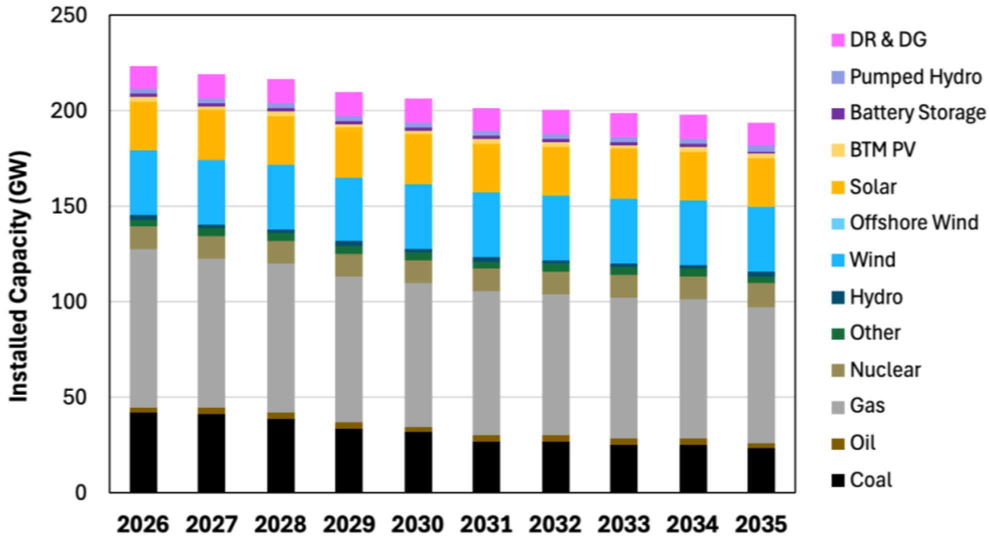


Figure 4-13: Existing Generation Resources Nameplate Capacity in MISO



Within the ComEd zone of PJM, depicted in Figure 4-14, the existing fleet consists largely of nuclear (11 GW) and natural gas (11 GW), with a relatively small remaining coal capacity (2.7 GW). Renewable generation is primarily wind, totaling 4.7 GW, along with a modest amount of utility-scale solar and growing levels of behind-the-meter (BTM) solar, modeled in accordance with statutory targets and projections in the IPA Long-Term Plan[164].

In MISO LRZ 4, which includes Ameren Illinois and municipal utilities and co-ops, the mix includes 3.8 GW of coal, 5.4 GW of natural gas, and 1.1 GW of nuclear. Wind and solar are more evenly balanced, with 4.4 GW of wind and 5.3 GW of solar in 2026. BTM solar is again included and projected to grow in line with Illinois policy requirements. These dynamics can be seen in Figure 4-15.

This study incorporates projected retirement dates for units affected by CEJA emissions standards, based on guidance provided by the IEPA. Where specific CEJA-related deadlines apply, those units are assumed to retire either in accordance with the policy, or before, if any announced retirement dates occur before the compliance date. Should a facility be identified as retiring in a given year to comply with CEJA (i.e., 2030), then that facility is assumed to be unavailable to contribute to summer resource adequacy needs in that year. This is further detailed in Appendix F.

It is important to note that the retirement assumptions represent a snapshot in time, based on the most current information. Some generating units may pursue operational changes—

[164] IPA Long-Term Renewable Resources Procurement Plan (October 20, 2025): https://ipa.illinois.gov/renewable-resources/long-term-plan.html.

such as fuel switching, emissions controls, or limited seasonal operation—to comply with CEJA without retiring. Therefore, inclusion of a retirement in this study does not constitute a legal or regulatory determination, nor does it imply that a particular unit will retire in practice. These assumptions should be interpreted as analytical inputs only and not definitive forecasts of future generator status.

Figure 4-14: Existing Generation Resources Nameplate Capacity in ComEd Zone

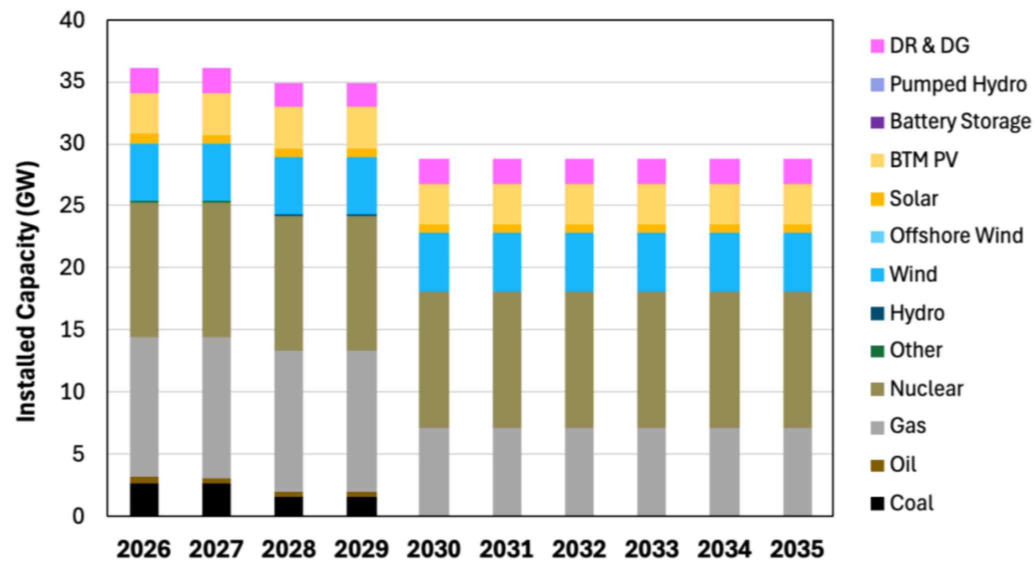
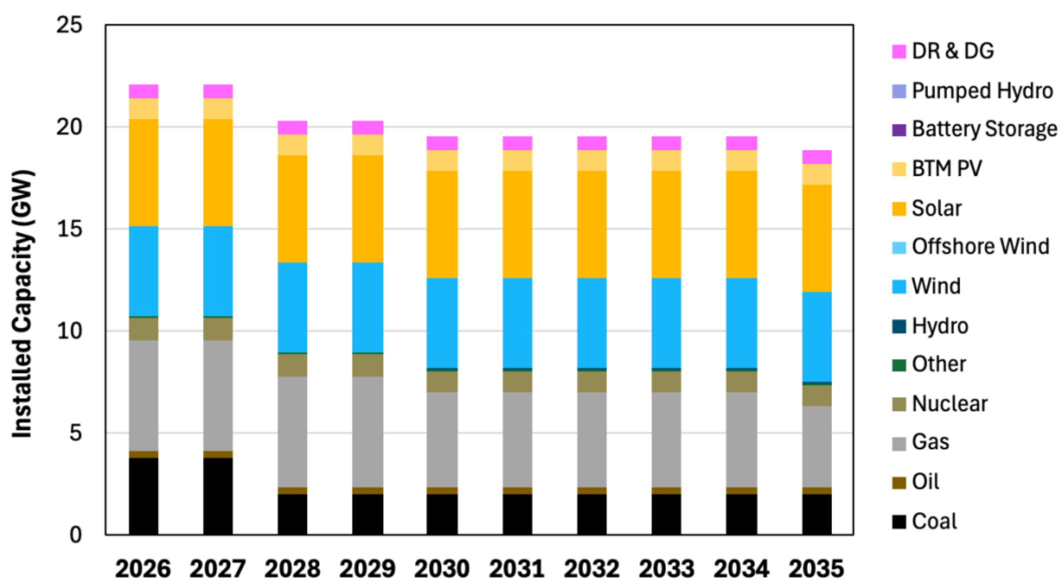


Figure 4-15: Existing Generation Resources Nameplate Capacity in MISO LRZ 4



In addition to the base retirement assumptions, this assessment evaluates a sensitivity case in which some units delay their retirement in response to evolving reliability needs or market conditions. These delayed retirements are applied to resources outside of Illinois only as units subject to CEJA policy are assumed to retire in accordance with the schedules discussed above. The goal of this sensitivity is to reflect the possibility that system operators or plant owners may postpone retirement decisions as resource adequacy tightens.

The effect of this assumption is illustrated in figures Figure 4-16 and Figure 4-17. In PJM, delayed retirements contribute between 12 and 17 GW of additional capacity between 2029 and 2035. In MISO, delayed retirements add between 12 and 26 GW over the same period.

Figure 4-16: Retirement Delay Sensitivity—Nameplate Capacity Impact in PJM

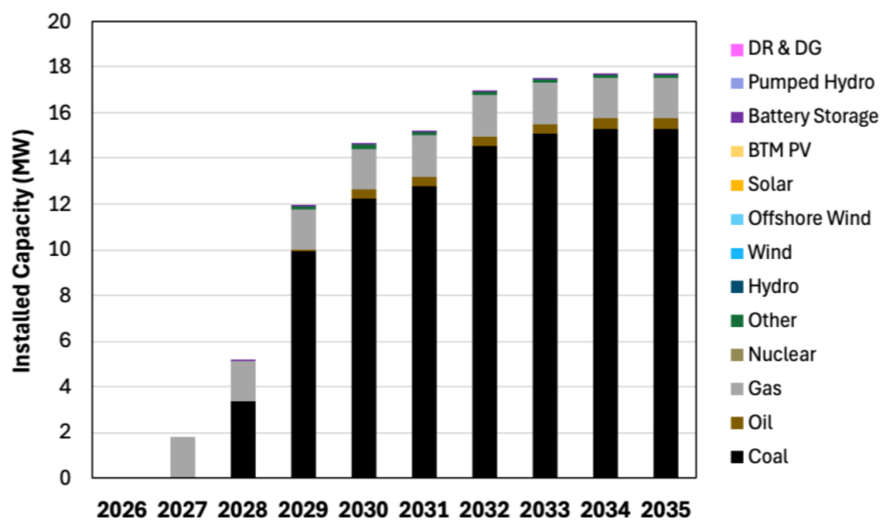
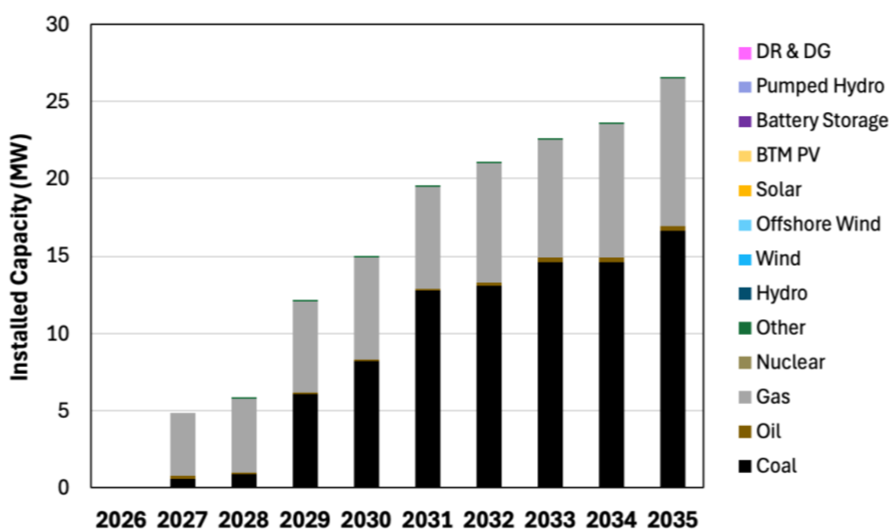


Figure 4-17: Retirement Delay Sensitivity—Nameplate Capacity Impact in MISO



4.2.2.2. New resources

Future generation capacity in both PJM and MISO over the next decade is expected to come primarily from resources currently progressing through the interconnection queues, along with a subset of fast-tracked reliability projects designated by each RTO. These new resources vary widely in development maturity, ranging from early-stage proposals to units already under construction. While the current queue is predominantly comprised of wind, solar, and battery projects, the mix of new entries to the queue could evolve over time depending on technology economics and commercial viability.

Figure 4-18 and Figure 4-19 depict all new resources in the queue that come online according to the as-reported Commercial Operation Date (COD). This data is drawn from the Velocity Suite database, which aggregates RTO queue data and applies in-house research to track project status and estimated online dates. Velocity Suite classifies queue projects into the following development categories: feasibility, proposed, application pending, permitted, under construction, and testing. Projects in the application pending, permitted, under construction, and testing stages are characterized as in an "advanced development," stage while those in feasibility and proposed stages are considered in an "early development" stage. Additional details on the assumptions for new resource capacity additions can be found in Appendix F.

The figures below show expected nameplate capacity additions in PJM and MISO by resource type and development stage. Under the as-reported COD assumption, PJM adds nearly 80 GW of new capacity by 2030, while MISO adds over 66 GW. Please note that these assumptions only add capacity based on resources currently in interconnection queues, and do not account for additional generating facilities to potentially be contracted for and energized across future years (such as new utility-scale wind or utility scale solar projects that may be supported through future procurements conducted to meet the Illinois RPS goals outlined in Chapter 3) in the Figures that follow.

Figure 4-18: Planned Resource Nameplate Capacity Additions in PJM

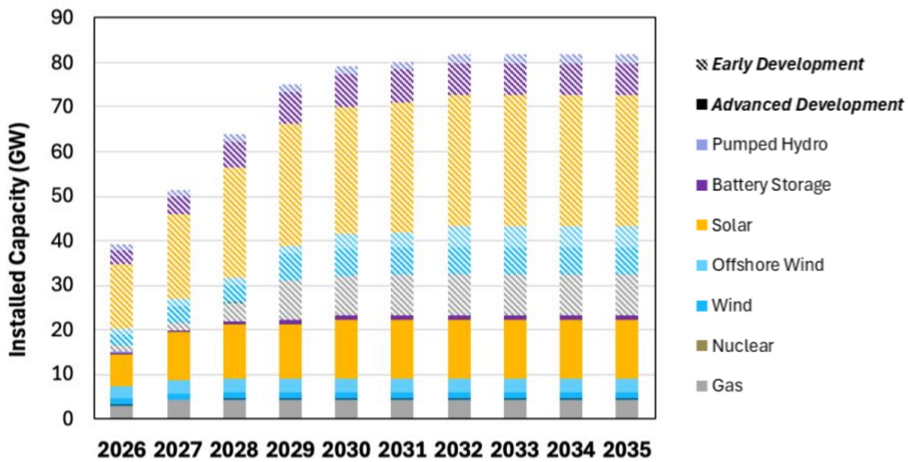
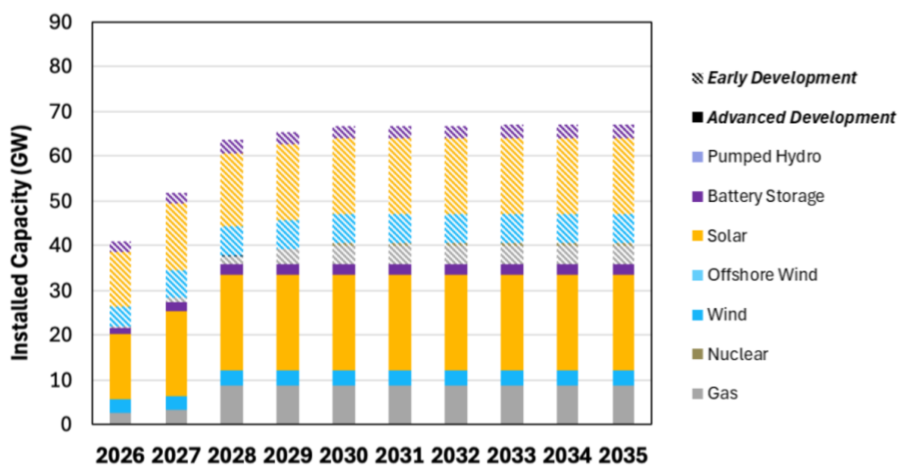


Figure 4-19: Planned Resource Nameplate Capacity Additions in MISO



Under as-reported COD assumptions, the ComEd zone is expected to add over 9 GW of new capacity by 2030, while MISO LRZ 4 adds over 11 GW, as depicted in Figure 4-20 and Figure 4-21. The values cited in this section are the plants' nameplate capacities, not the ELCC values that represent the plants' contribution to resource adequacy.

Figure 4-20: Planned Resource Nameplate Capacity Additions in ComEd Zone

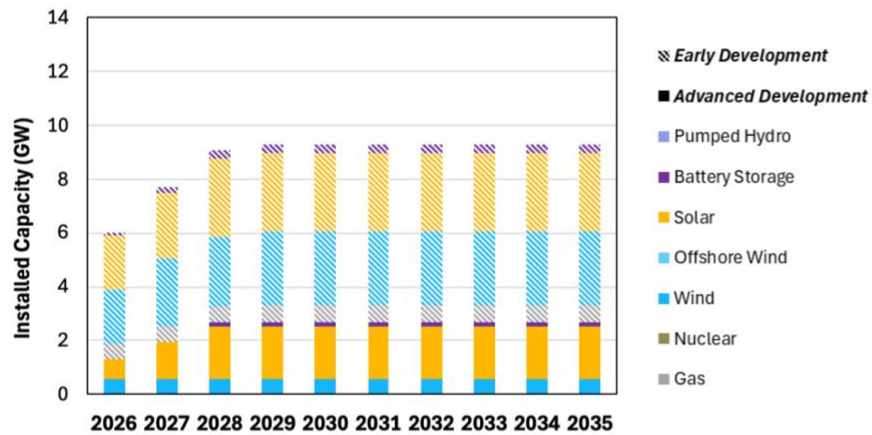
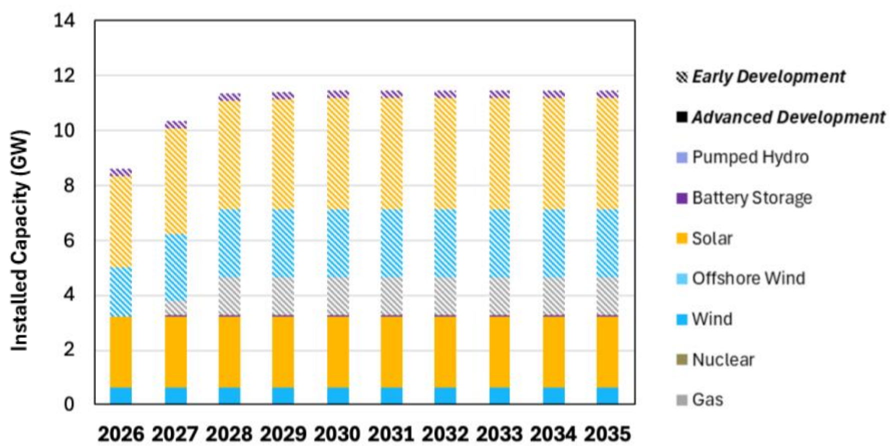


Figure 4-21: Planned Resource Nameplate Capacity Additions in MISO LRZ 4



To reflect the practical challenges developers face—including interconnection process delays, supply chain constraints, and siting or permitting issues—an alternative outlook applies realistic delays to project CODs based on project maturity. The following delays are applied based on each project's development stage and are not cumulative across stages (i.e., each project receives a single delay based on its current status, not the sum of delays across all prior stages):

- Under construction and testing: 0-1 year
- Permitted: +2 years
- Application pending: +3 years
- Feasibility: +4 years
- Proposed: +5 years

Figure 4-22 and Figure 4-23 show the impact of these delays. Under this assumption, PJM adds just over 20 GW of new nameplate capacity by 2030, while MISO adds just over 28 GW.

Figure 4-22: Planned Resource Nameplate Capacity Additions in PJM—Delay Scenario

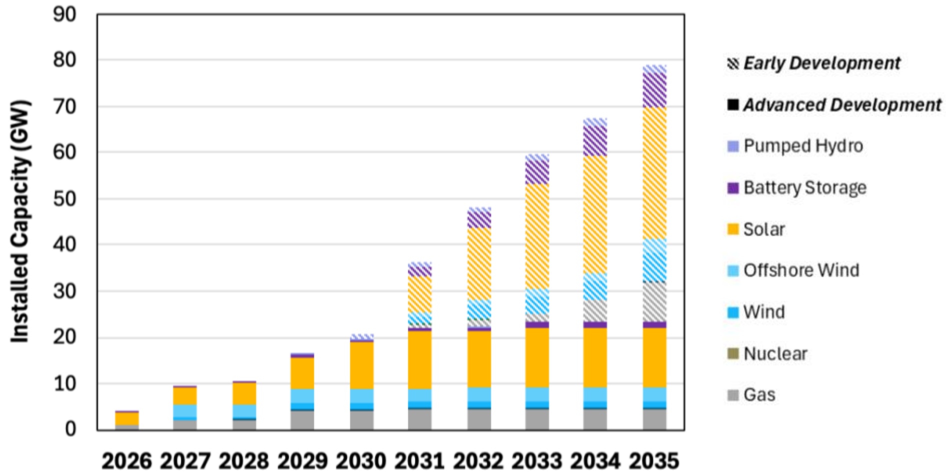
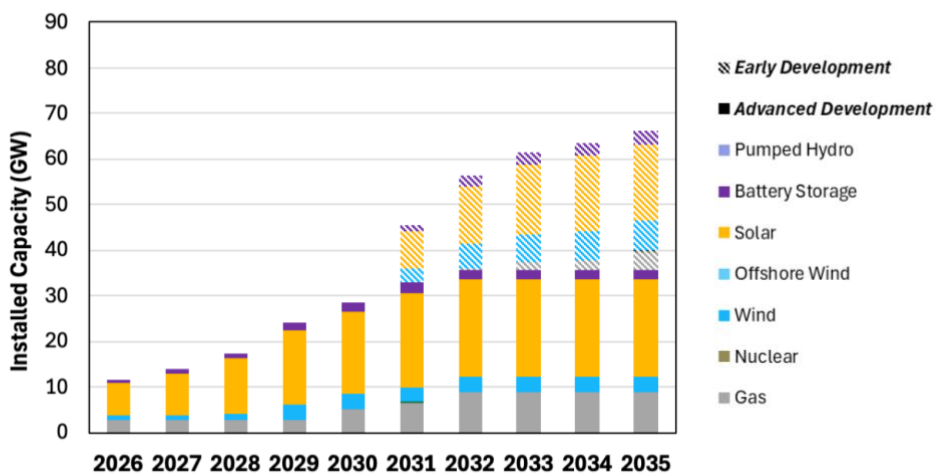


Figure 4-23: Planned Resource Nameplate Capacity Additions in MISO—Delay Scenario



When delays are applied, the ComEd zone is projected to bring online around 2 GW of nameplate capacity by 2030, with the full 9 GW realized by around 2033. Similarly, MISO LRZ 4 sees just over 3 GW by 2030, reaching the full 11 GW also by approximately 2033. These dynamics are illustrated in Figure 4-24 and Figure 4-25.

Figure 4-24: Planned Resource Nameplate Capacity Additions in ComEd Zone—Delay Scenario

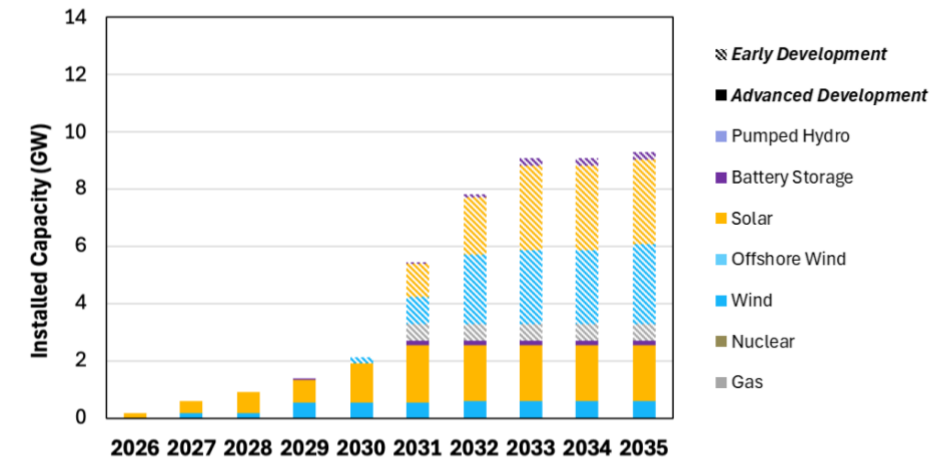
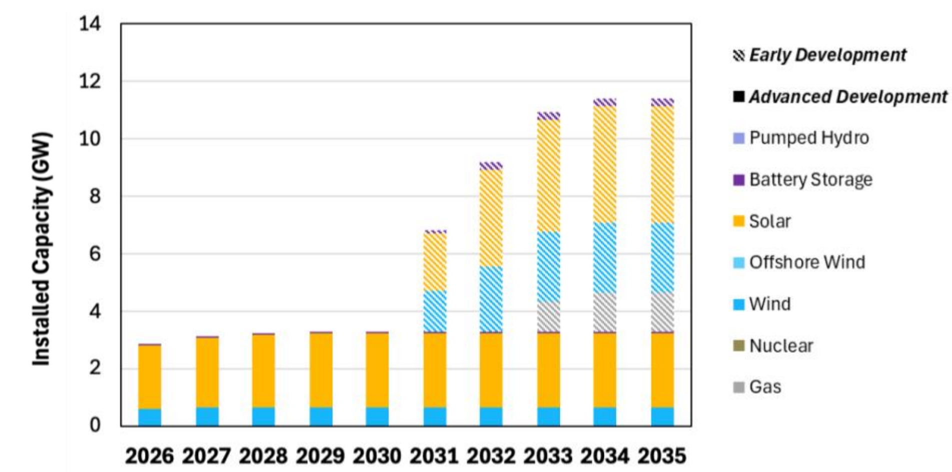


Figure 4-25: Planned Resource Nameplate Capacity Additions in MISO LRZ 4—Delay Scenario



In parallel with standard queue developments, both RTOs have identified a subset of priority reliability resources expected to come online without delay. These are treated separately from queue-based projects in this analysis.

- In PJM, the Reliability Resource Initiative (RRI)[165] identifies specific capacity additions or existing generator uprates needed to address near-term system constraints and mitigate reliability risks flagged during the 2023–2024 capacity auctions. These

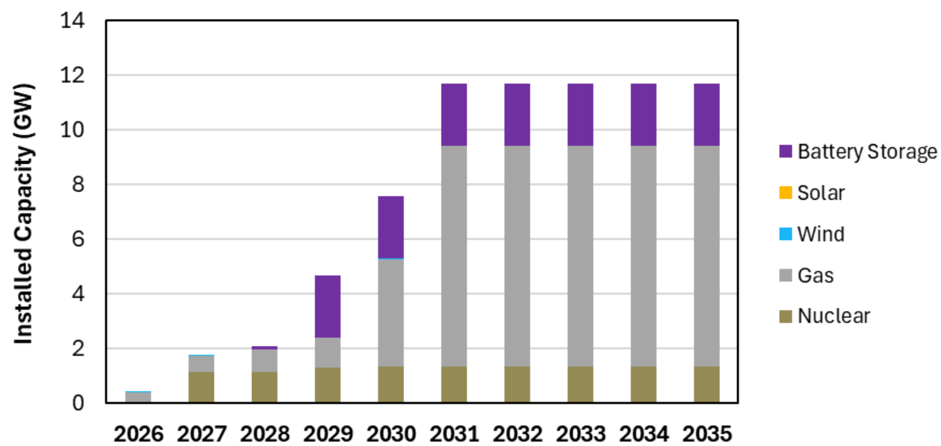
[165] Tariff Revisions for Reliability Resource Initiative, PJM Interconnection: 20241213-er25-712-000.pdf.

projects are assumed to come online as scheduled and are exempt from the COD delay assumptions.

- In MISO, the Expedited Resource Addition Study (ERAS)[166] serves a similar role, designating key capacity resources that the RTO expects to interconnect and operate on an accelerated basis to maintain system resource adequacy. While the first set of resources are reflected in this analysis, MISO is evaluating additional projects for future ERAS considerations.

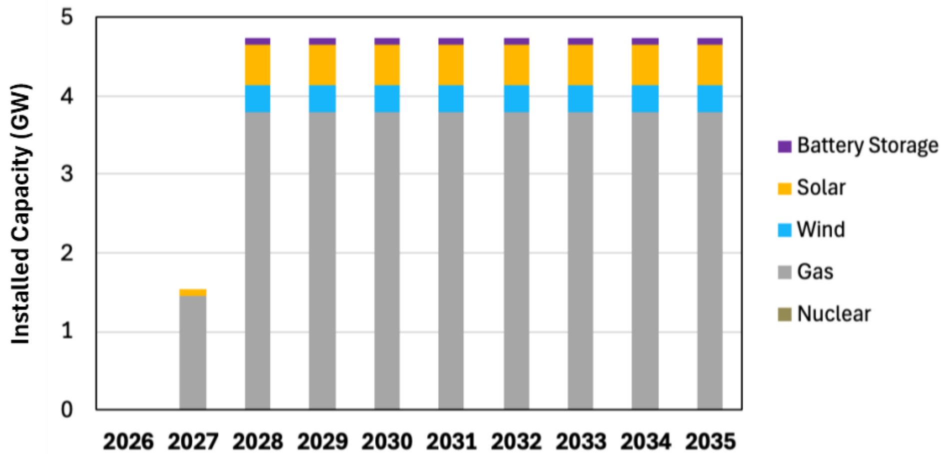
Together, these programs are projected to contribute an additional 7 GW of nameplate capacity in PJM and 5 GW in MISO by 2030 based on current reported data (subject to future increases should the RTOs expand the programs). Of these projects, the ComEd zone has capacity uprates to existing nuclear and gas facilities totaling 313 MW and the MISO LRZ 4 zone has one 125 MW solar project. These fast-tracked additions, shown in Figure 4-26 and Figure 4-27, are included in both the as-reported and delay scenarios of this analysis, given their elevated priority and explicit intent to meet short-term regional needs.

Figure 4-26: Planned Resource Capacity Additions in PJM RRI Queue



[166] FERC Approves MISO's Expedited Resource Addition Study: https://www.misoenergy.org/meet-miso/media-center/2025---news-releases/ferc-approves-misos-expedited-resource-addition-study/.

Figure 4-27: Planned Resource NRIS Capacity Additions in MISO ERAS Queue



While interconnection queue data is publicly available from PJM and MISO, this analysis uses the Velocity Suite database to enhance transparency and screening of projects by development stage. Velocity Suite not only aggregates queue data but also incorporates internal research to assess project viability and assign realistic development status categories. This screening process helps avoid overestimating near-term capacity additions. For example, MISO's interconnection queue[167] includes approximately 78 GW of active projects with assigned study phases and in-service dates 2025 and beyond, plus an additional 180 GW of projects that have not yet started the study process as of November 20, 2025. By contrast, Velocity Suite's filtered dataset for MISO includes about 67 GW, reflecting a more realistic view of probable development. In PJM, the difference is narrower: Velocity Suite identifies 83 GW of projects, compared to 88 GW in the PJM queue[168], as of November 20, 2025, after filtering for active status and in-service dates beyond 2025.

4.2.3. Resource Capacity Accreditation and Resource Adequacy Standards

To evaluate whether projected resources are sufficient to meet long-term electric reliability needs, this analysis applies capacity accreditation values and resource adequacy requirements consistent with the planning constructs used by each RTO. Together, these two inputs define how much of a resource's installed capacity can be counted toward meeting the RTO's reliability target and how much capacity is needed to satisfy those targets.

[167] Generator Interconnection Queue, MISO: GI Interactive Queue.
[168] Interconnection / Upgrade Requests, PJM: PJM - Interconnection / Upgrade Requests.

Both PJM and MISO have adopted technology-neutral capacity, "critical periods"[169] accreditation frameworks that apply probabilistic, performance-based ELCC methods across all resource types, including conventional thermal, renewable, storage, and demand-side resources. ELCC methodologies ensure that the unique operational characteristics of each resource type, including variability and uncertainty, are fairly reflected in how resources are counted toward meeting resource adequacy needs.

In parallel, each RTO sets system-level resource adequacy requirements which represent the amount of accredited capacity needed to reliably serve load while maintaining an acceptable loss-of-load expectation. In PJM, the system planning reserve margin is embedded in the FPR[170], which applies a reserve margin and derating factors to the forecasted peak load. In MISO, RA requirements are based on outputs from the annual Loss of Load Expectation Study and associated DLOL analyses[171]. These studies simulate a wide range of conditions including weather variability, forced outages, and load uncertainty to establish the planning reserve margin needed to meet the "1-day-in-10-years" reliability standard. For this study, E3 applies the most recently published ELCC accreditation values and resource adequacy targets by PJM and MISO as of the 2026/2027 planning horizon. Please see Appendix F for additional information regarding the resource adequacy targets and accreditations applied in this analysis.

4.2.3.1. PJM and MISO ELCCs

PJM employs a probabilistic based accreditation methodology to assess the contribution of each resource class to system reliability. PJM calculates resource accreditation based using its Resource Reliability Analytics (RRA) model[172] which simulates system performance under various conditions to estimate each resource's contribution to reducing system unserved energy. The primary measurement is the Marginal Reliability Improvement Metric (MRIM),[173] which evaluates how incremental capacity of a given resource type improves system reliability, measured as a reduction in Expected Unserved Energy (EUE). This

[169] "Resource Adequacy for the Energy Transition: A Critical Periods Reliability Framework and its Applications in Planning and Markets," Energy and Environmental Economics (E3), Inc. (August 2025): https://www.ethree.com/wp-content/uploads/2025/08/E3_Critical-Periods-Reliability-Framework_White-Paper.pdf.

[170] 2025 PJM Effective Load Carrying Capability and Reserve Requirement Study, PJM: 2025-pjm-elcc-rrs.pdf.

[171] Planning Year 2026-2027 Loss of Load Expectation Study Initial Report, MISO: PY 2026-2027 LOLE Study Report.

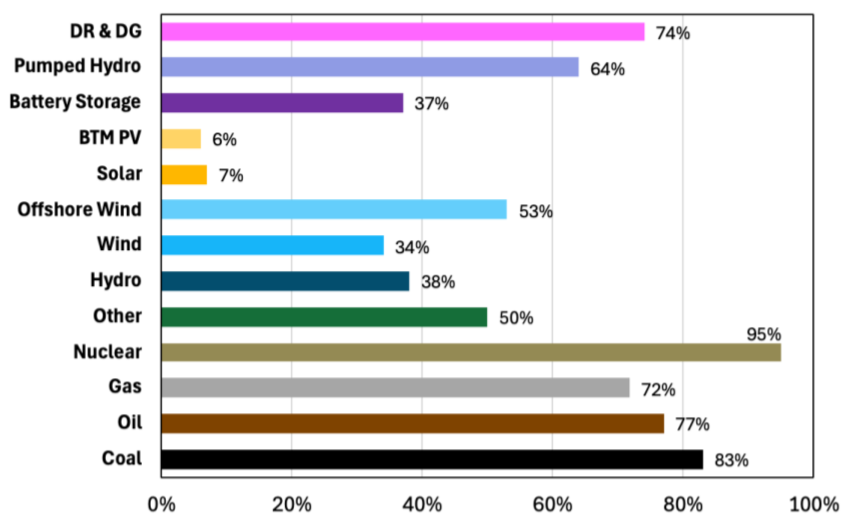
[172] 2025 PJM Effective Load Carrying Capability and Reserve Requirement Study, PJM: https://www.pjm.com/-/media/DotCom/planning/res-adeq/elcc/2025-pjm-elcc-rrs.pdf.

[173] This accreditation is called "ELCCs" or "marginal ELCCs" in PJM documents. However, there are slight differences in the way PJM calculates this accreditation and how ELCCs have been calculated for this study. To avoid confusion, we will refer to PJM's values as MRI accreditation. For more details see Appendix F.

ensures that accreditation values reflect not just a resource's availability but also its incremental value to system reliability in the context of the broader resource mix.

PJM publishes annual preliminary MRI-based ELCCs ratings that forecast accreditation factors by resource type for a 10-year horizon. The load resource balance analysis in this chapter uses the full set of MRI-based ELCCs values from PJM's 2026/2027 through 2035/2036 delivery years, as presented in the latest ratings document.[174] These MRI-based ELCCs are applied consistently to both existing and new resources in the PJM system and the Illinois ComEd zone. The values for 2030 are shown in Figure 4-28.

Figure 4-28: PJM Projected MRI-based ELCCs by Resource Type in 2030



MISO is also transitioning to a probabilistic accreditation framework. Under the methodology, all resources will be accredited using a combination of the DLOL method and seasonal UCAP calculations as described in its accreditation reform process.[175]

For the 2025–2026 planning cycle, MISO has published indicative DLOL results,[176] which provide resource-class level capacity accreditation values for wind, solar, storage, and conventional resources. These values form the starting point for accreditation assumptions used in this study's near-term resource adequacy balance and are applied uniformly across MISO-wide and Illinois (LRZ 4) zones. To reflect how accreditation values may evolve, this

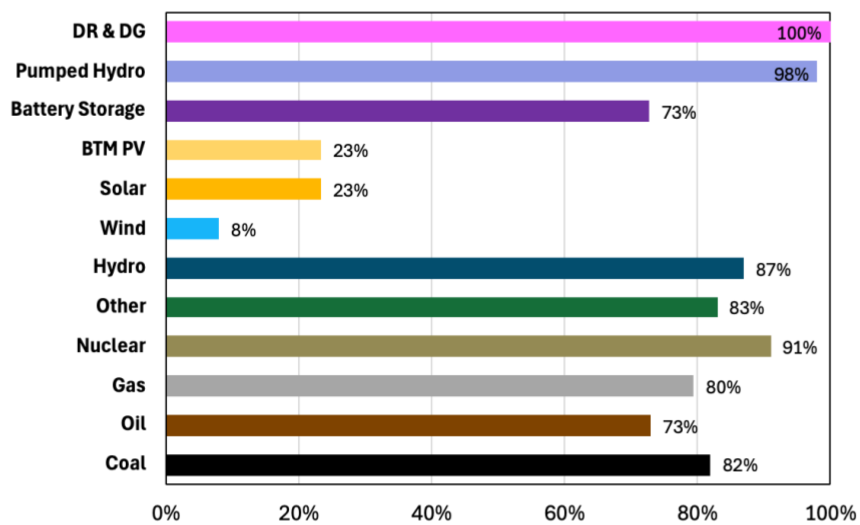
[174] Preliminary ELCC Class Ratings for Period Delivery Year 2027/28 – Delivery Year 2035/36: https://www.pjm.com/-/media/DotCom/planning/res-adeq/elcc/preliminary-elcc-class-ratings.pdf

[175] MISO Resource Accreditation White Paper Version 2.1: https://cdn.misoenergy.org/Resource%20Accreditation%20White%20Paper%20Version%202.1630728.pdf

[176] MISO Planning Year 2025-2026 Indicative Direct Loss of Load (DLOL) Results: https://cdn.misoenergy.org/PY%2025-26%20Indicative%20DLOL%20Results657893.pdf

study also draws on the forecasted DLOL results published in the technical appendix of MISO's 2024 Regional Resource Assessment (RRA). These materials indicate that DLOL values for solar and battery storage, in particular, vary meaningfully as installed capacity increases, while DLOL values for wind and conventional resources remain relatively stable over time. Accordingly, this analysis does not apply a single fixed DLOL percentage for solar and storage across the full modeling horizon but instead applies calculated DLOL values for solar and storage based on resource penetration levels, utilizing the relationship between installed capacity and DLOL observed in the 2025–2026 indicative results and forward-looking DLOL tables provided in the RRA technical appendix. For wind and other resource types whose accreditation values change minimally across the RRA projections, the 2025–2026 indicative DLOL values are held constant through 2035. The DLOL values used in this assessment for the year 2030 are shown in in Figure 4-29.

Figure 4-29: MISO Projected DLOL values by Resource Type in 2030



4.2.3.2. PJM and MISO Resource Adequacy Requirements

PJM sets its resource adequacy requirements, shown in Figure 4-30, through the Forecast Pool Requirement, a system-wide metric that translates the Installed Reserve Margin (IRM) into the amount of UCAP required to meet reliability standards. The FPR incorporates both the reserve margin and average forced outage rates across the system, allowing for a consistent planning benchmark across resource types. The FPR, shown in Figure 4-31, is applied as a multiplier to forecasted peak demand and used in all capacity market constructs, including the PJM BRA and RPM. In this study, the near-term resource adequacy balance (2026–2035) adopts PJM's FPR trajectory as published, holding those values constant beyond 2026/2027 in cases where forward estimates are not available.

Figure 4-30: PJM Resource Adequacy Requirement (GW) 2026-2035

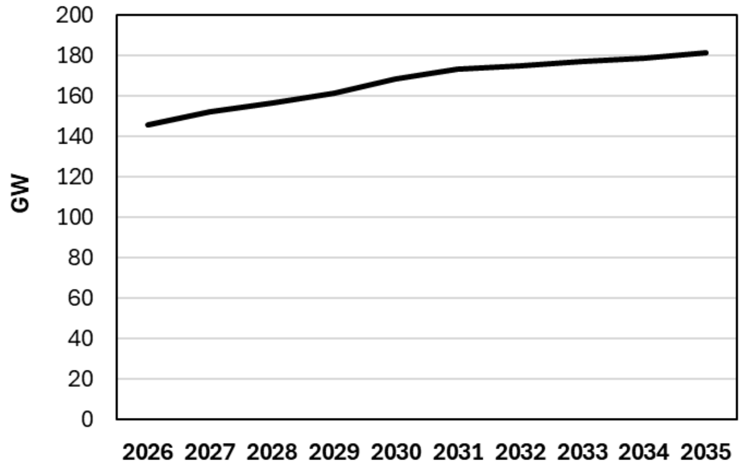
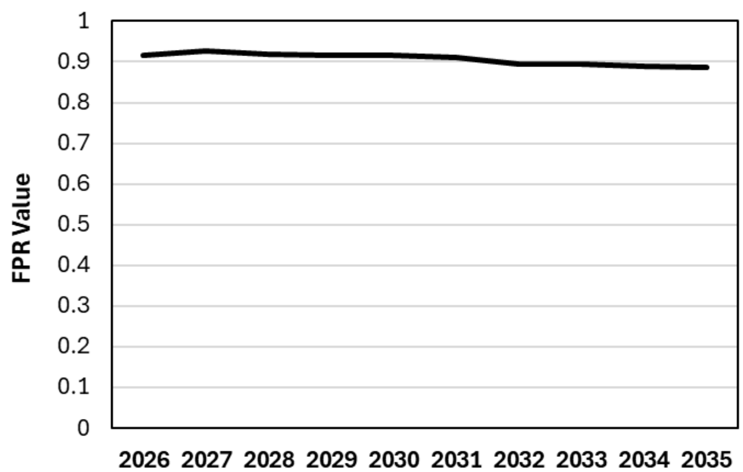


Figure 4-31: PJM Forecast Pool Requirement 2026-2035



MISO determines its system-wide capacity needs through its annual Loss of Load Expectation Study, which assesses reliability based on probabilistic modeling of generator outages, load variability, weather conditions, and system stress events. The results of this study define the Planning Reserve Margin Requirement (PRMR), the minimum accredited capacity needed to maintain a one-day-in-ten-year LOLE standard. For this study's near-term RA balance, E3 uses the PRMR and accreditation assumptions from the 2025–2026 indicative DLOL studies to define MISO-wide and zonal adequacy targets. The PRMR values are held constant through 2035, shown in Figure 4-33, and the MISO-wide requirement is shown in Figure 4-32.

Figure 4-32: MISO Resource Adequacy Requirements (GW) 2026-2035

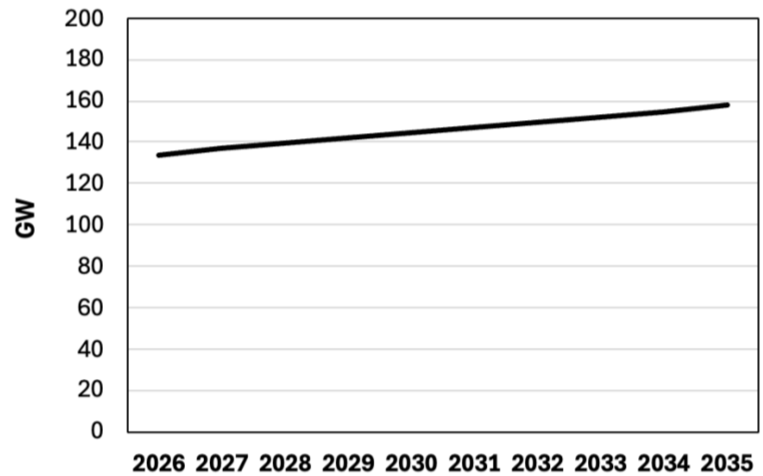
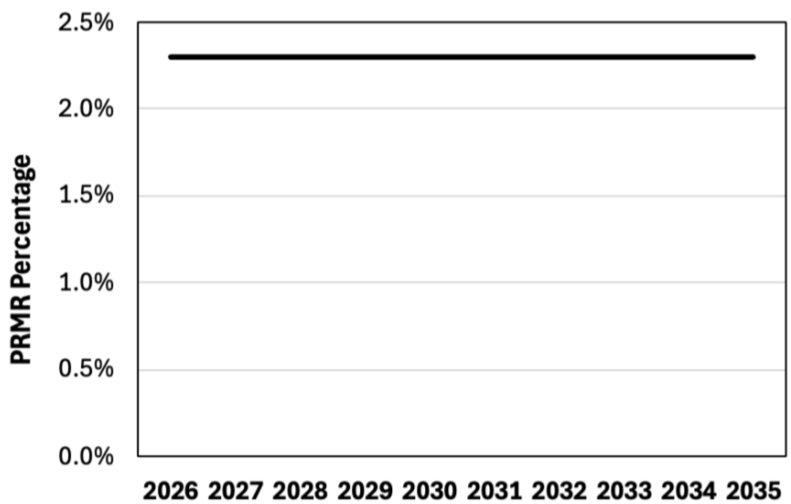


Figure 4-33: MISO Planning Reserve Margin Requirement 2026-2035



4.2.4. RTO-Wide Resource Adequacy Balances

Before evaluating resource adequacy outcomes specific to Illinois, it is important to first understand the broader conditions within the two RTOs that serve the state. Because resource adequacy is managed at the RTO level, Illinois does not function in isolation; it participates in a pooled system operated by the RTO in which all load-serving entities contribute to, and depend on, the adequacy of regional supply. As such, even if resources within an Illinois zone are sufficient to meet that zone's allocated share of the RTO's resource adequacy requirement, Illinois would still be exposed to the consequences of a system-wide shortfall. These could include higher capacity prices and elevated risks of loss of load events, potentially including rotating blackouts. The following analysis presents

RTO-wide supply and demand conditions through 2035 to establish this broader context before turning to Illinois-specific results.

Based on current load forecasts and resource adequacy targets, both PJM and MISO are projected to be at risk of facing capacity shortfalls over the coming decade unless additional new capacity resources are developed, as depicted in Figure 4-34 and Figure 4-35. PJM's resource adequacy target increases by approximately 20% between 2025 and 2030, while MISO's target grows by around 10% over the same period, driven primarily by rapid load growth from data center development on top of native load growth. Both RTOs have significant volumes of new capacity in development—nearly 87 GW in PJM and over 72 GW in MISO of new nameplate capacity by 2030. However, a majority of these new resources are variable and intermittent renewable energy projects; when the resource nameplate capacities are adjusted to reflect accredited capacity, the values decrease to 27 GW in PJM and 28 GW in MISO. At the same time, accredited capacity retirements are projected to reach nearly 15 GW in PJM and 18 GW in MISO, primarily consisting of aging thermal generators. When accounting for these supply and demand dynamics, including both announced retirements and those additional plant retirements forecast to occur to achieve CEJA emissions reduction compliance, as well as accredited new builds currently in the queue or fast-tracked through the PJM RRI or MISO ERAS programs, PJM is projected to experience a capacity shortfall beginning in 2029, with the deficit widening in subsequent years. MISO remains resource adequate through 2030, but a shortfall is projected to emerge in 2031 and grow thereafter. These projections reflect baseline conditions and assume no acceleration or delays in new resource development or retirements.

Figure 4-34: PJM RA Balance (2026-2035) | Resource Additions and Retirements "As-Reported"

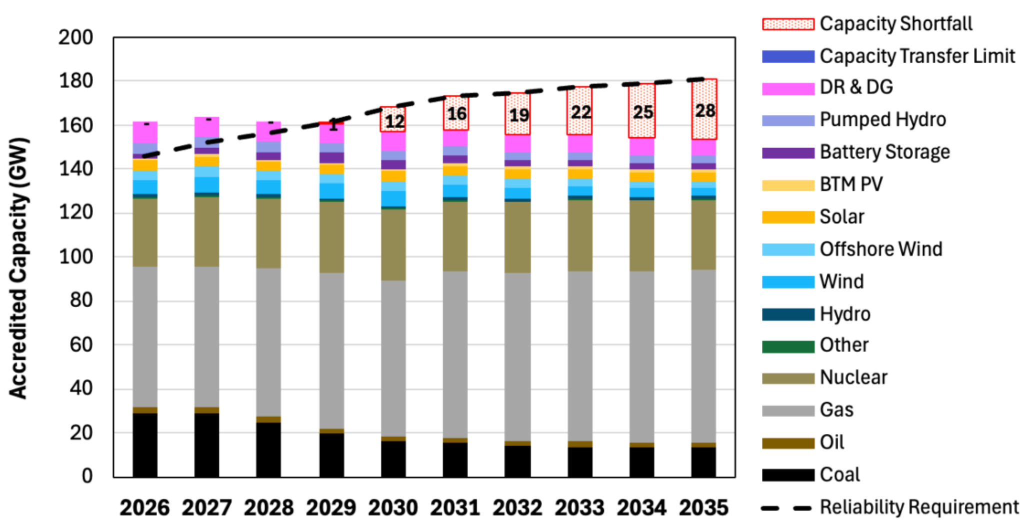
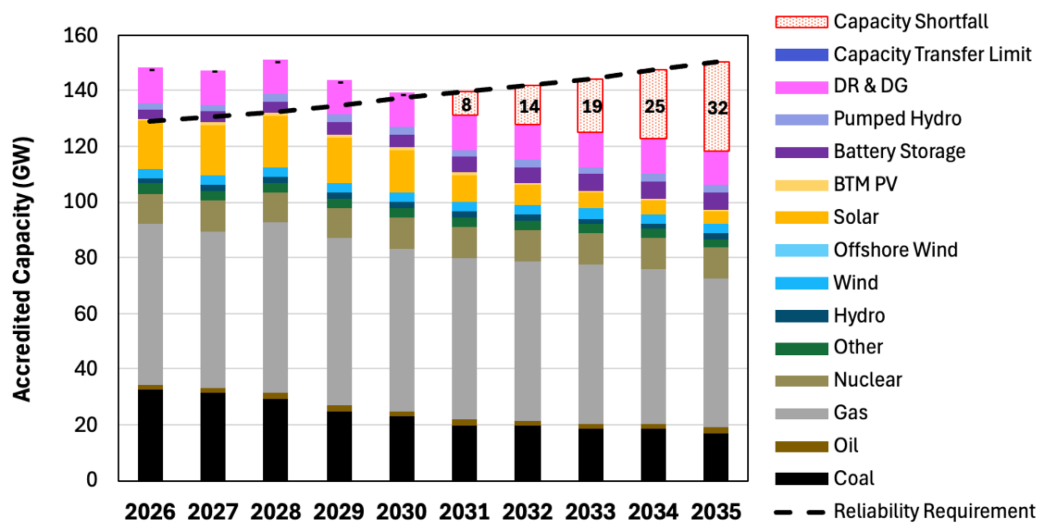


Figure 4-35: MISO RA Balance (2026-2035) | Resource Additions and Retirements "As-Reported"



When realistic development delays are applied to planned resource additions, the projected resource adequacy outlook worsens for both PJM and MISO. These projected delays reflect ongoing supply chain constraints, uncertainty related to federal trade policy and tariffs, sourcing restrictions tied to Foreign Entities of Concern (FEOCs),[177] and the extended timelines associated with navigating RTO interconnection processes. Under these assumptions, no delay is applied to fast-tracked resources in PJM's RRI and MISO's ERAS programs. However, all other resources in the interconnection queue are assumed to experience average delays as described above in 4.2.2.2.

With these adjusted timelines, PJM's projected capacity shortfall first appears in 2028, and the projected shortfall grows to 27 GW by 2030, as shown in Figure 4-36. MISO's projected shortfall emerges in 2029 and reaches 12 GW by 2030, detailed in Figure 4-37. These findings underscore the importance of timely project execution and the risks associated with relying on resources that may be in the queue but may not achieve commercial operations on schedule. Delays of this nature materially reduce the accredited capacity available to meet rising resource adequacy requirements.

[177] "One Big Beautiful Bill: New Law Disrupts Clean Energy Investment," Latham & Watkins LLP, *Client Alert*, (July 8, 2025): https://www.lw.com/admin/upload/SiteAttachments/One-Big-Beautiful-Bill-New-Law-Disrupts-Clean-Energy-Investment.pdf

Figure 4-36: PJM RA Balance (2026-2035) | Delayed Resource Additions

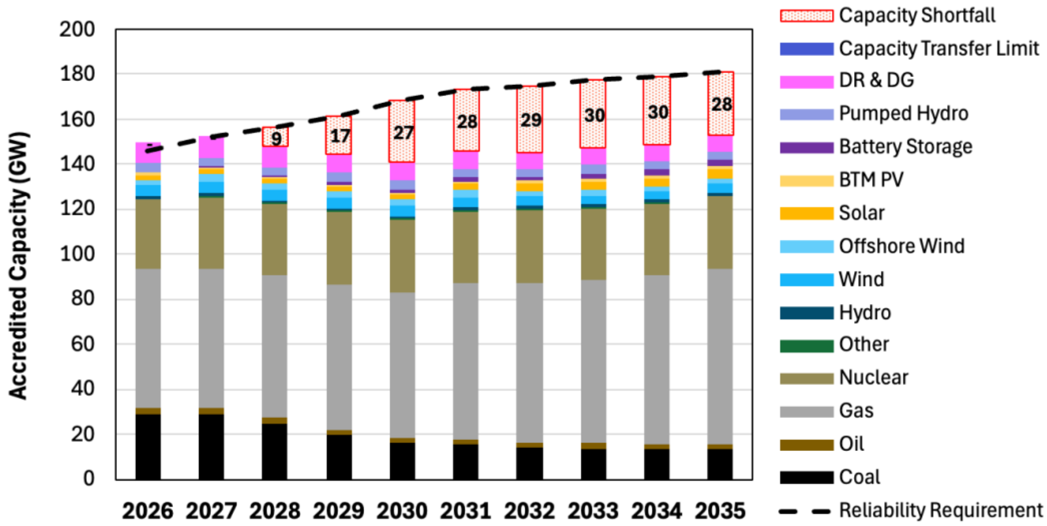
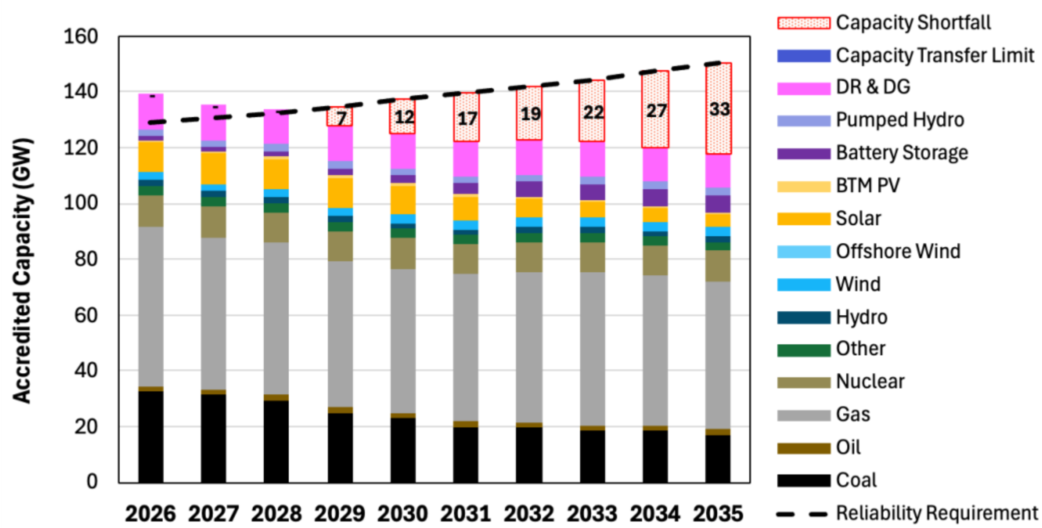


Figure 4-37: MISO RA Balance (2026-2035) | Delayed Resource Additions



In response to emerging signs of capacity shortfalls, both RTOs and developers are already adjusting their behavior—whether by seeking to defer planned generator retirements, accelerating projects through fast-track interconnection pathways like PJM's RRI and MISO's ERAS programs, or efforts to moderate large load additions like PJM's Critical Issue Fast Path (CIFP).[178] These actions reflect a clear recognition of the growing reliability risks facing the system. However, these efforts are only able to mitigate the shortfall to an extent.

[178] Critical Issue Fast Path, PJM: PJM - Critical Issue Fast Path - Large Load Additions.

When delays in new resource development are accounted for alongside assumed deferrals of retirements outside of Illinois, illustrated in Figure 4-39, the projected shortfall in PJM still begins in 2028, and by 2030 reaches 16 GW, an improvement from the 27 GW shortfall under the delayed build case. In MISO, the outcome in Figure 4-39 shows the first projected shortfall is pushed out to 2030 from 2029, and the 2030 shortfall drops to 2 GW (down from 12 GW). Retirement deferrals help reduce the magnitude of system-wide capacity gaps, but they do not eliminate the underlying need for more timely and reliable new resource development to meet growing demand. While the delays in generator retirements are assumed across each RTO, these scenarios do not assume any changes in the retirement schedule for Illinois generators covered by CEJA emissions limits.

Figure 4-38: PJM RA Balance (2026-2035) | Delayed Resource Additions & Retirements

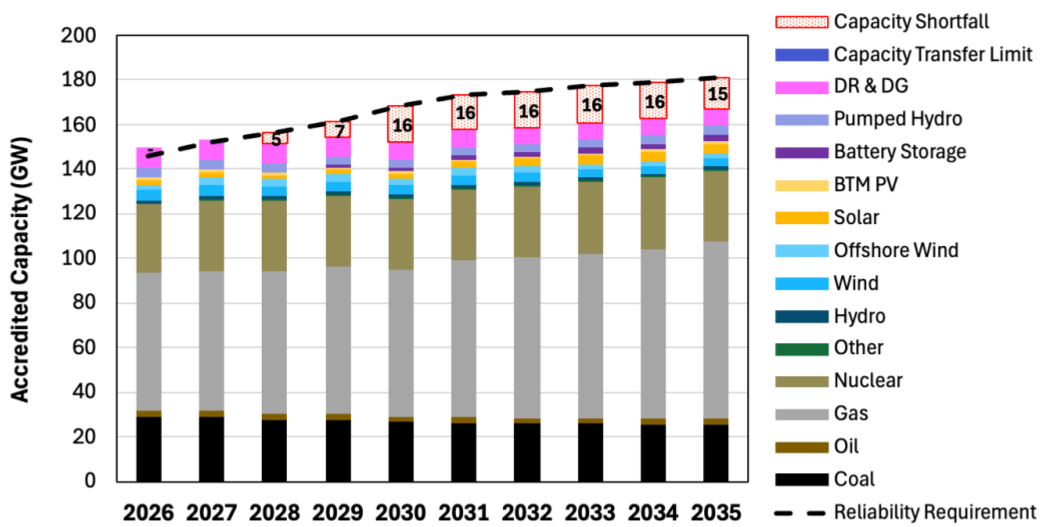
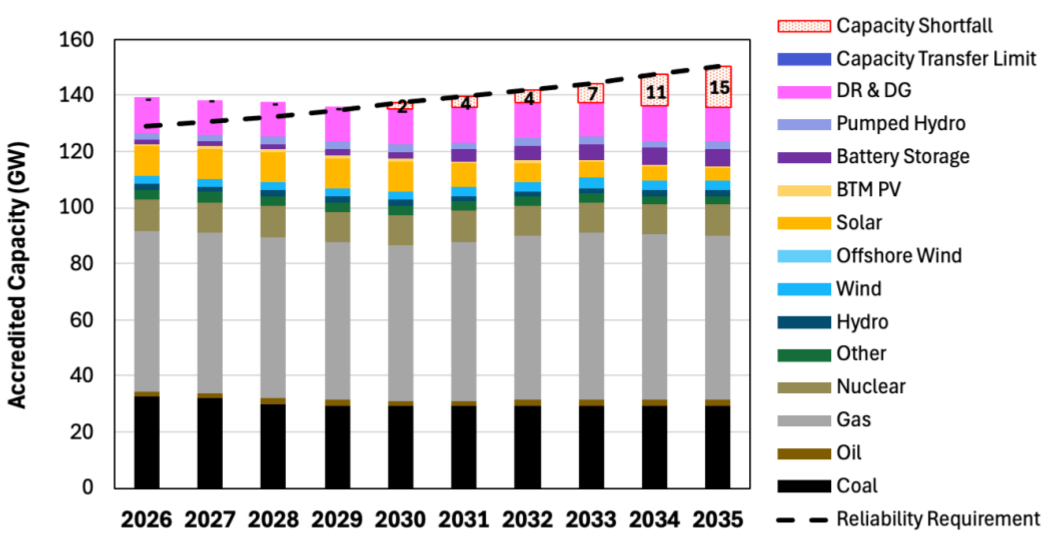


Figure 4-39: MISO RA Balance (2026-2035) | Delayed Resource Additions & Retirements



4.2.5. Illinois Resource Adequacy Balance

The preceding results illustrate the broader system-wide supply and demand conditions in PJM and MISO through 2035. As a continuation of this analysis, this section evaluates resource adequacy in the ComEd zone (the Illinois zone in PJM) and MISO LRZ 4 (the primary Illinois zone in MISO). Both PJM and MISO conduct zonal resource adequacy assessments as part of their capacity market structures to ensure that each zone has access to sufficient deliverable capacity. These zonal assessments are informed by transmission transfer capabilities, specifically the Capacity Emergency Transfer Limit (CETL) in PJM and the Zonal Import Ability (ZIA) in MISO, which define how much capacity can reliably flow into each zone from other segments of the system during critical hours.

The following figures incorporate these transfer limits to evaluate whether Illinois' zones meet their respective reliability requirements. However, it is important to note that these metrics assume the broader RTO has sufficient surplus capacity available to support these transfers. If the RTO is short on capacity during the critical hours in which imports are required, as established in the previous section, Illinois cannot rely on those imports from neighboring zones to maintain resource adequacy. In that context, system-wide resource adequacy is a prerequisite for zonal RA balances to be meaningful. Even if a zone appears to meet its internal planning requirement, it will remain exposed to the consequences of a regional shortfall, which may result in capacity price spikes, transmission line congestion, and elevated loss of load risk. This section presents the ComEd zone in PJM and MISO LRZ 4 outcomes under consistent assumptions used in the RTO-wide analysis.

Under conditions where new resources are in-service according to their reported commercial operation dates and RTO-wide retirements proceed as planned, the resource adequacy outlook for Illinois' two zones diverges notably, depicted in Figure 4-40 and Figure 4-41. The ComEd zone meets its zonal requirements through 2032 but begins to rely on imports from the broader PJM system via the CETL starting in 2030. Load growth in the zone drives a substantial increase in resource adequacy requirements, rising by 24% between 2025 and 2030, which contributes to growing dependence on external capacity even before the onset of a projected shortfall in 2032.

In contrast, MISO LRZ 4 meets its zonal requirements through 2035. The zone experiences a more modest increase in its resource adequacy requirement, approximately 11% from 2025 to 2030, and has sufficient in-zone accredited capacity to meet its needs through 2030 before beginning to rely on imports through 2035. Even though the LRZ 4 zonal capacity balance appears sufficient, emerging reliance on interzonal transfers and the MISO-wide results indicate a risk of shortfall at the system level, which poses a corresponding resource adequacy risk for Illinois consumers.

Figure 4-40: Illinois ComEd Zone RA Balance (2026-2035) | Resource Additions and Retirements "As-Reported"

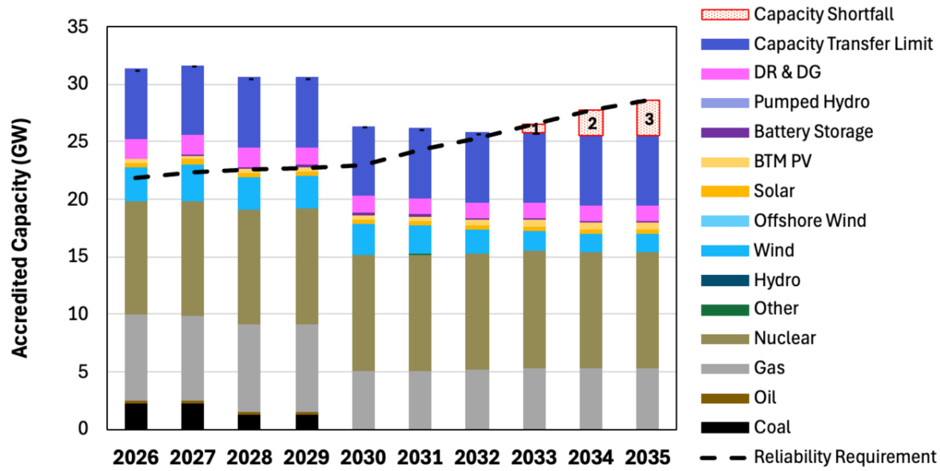
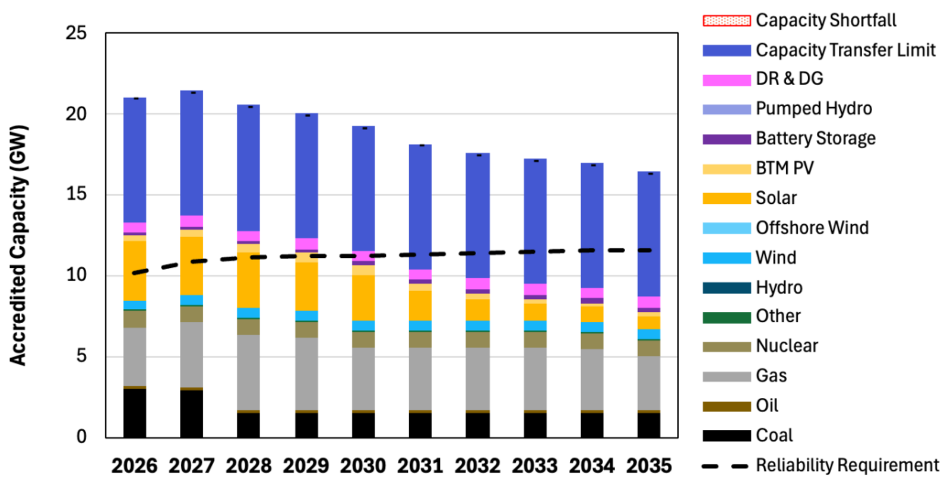


Figure 4-41: Illinois MISO LRZ 4 RA Balance (2026-2035) | Resource Additions and Retirements "As-Reported"



When delays in commercial operation dates are applied to new resource additions, both Illinois zones experience tighter supply-demand balances, shown in Figure 4-42 and Figure 4-43, though the impacts vary. In the ComEd zone of PJM, the effect is modest: the zone remains resource adequate through 2032, but only just meets its requirement that year. The zone continues to rely on imports from the broader PJM system. In MISO LRZ 4, the impact is more significant. While the zone had previously maintained a comfortable surplus, with COD delays applied, it becomes reliant on its ZIA from 2028 to 2035, and the balance between in-zone resources and demand becomes tighter. Although LRZ 4 remains adequate from its large import capability, its margin shrinks. Still, the broader concern is that both zones remain part of RTOs that are projected to face system-wide capacity shortfalls, meaning that the ability to rely on imports, even if enabled by CETL or ZIA limits, may not be feasible in practice.

Figure 4-42: Illinois ComEd Zone RA Balance (2026-2035) | Delayed Resource Additions

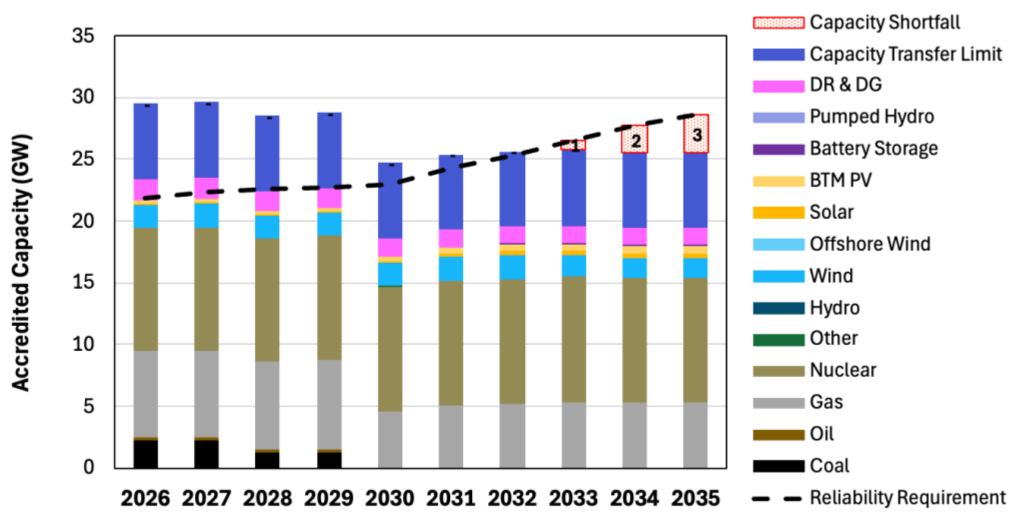
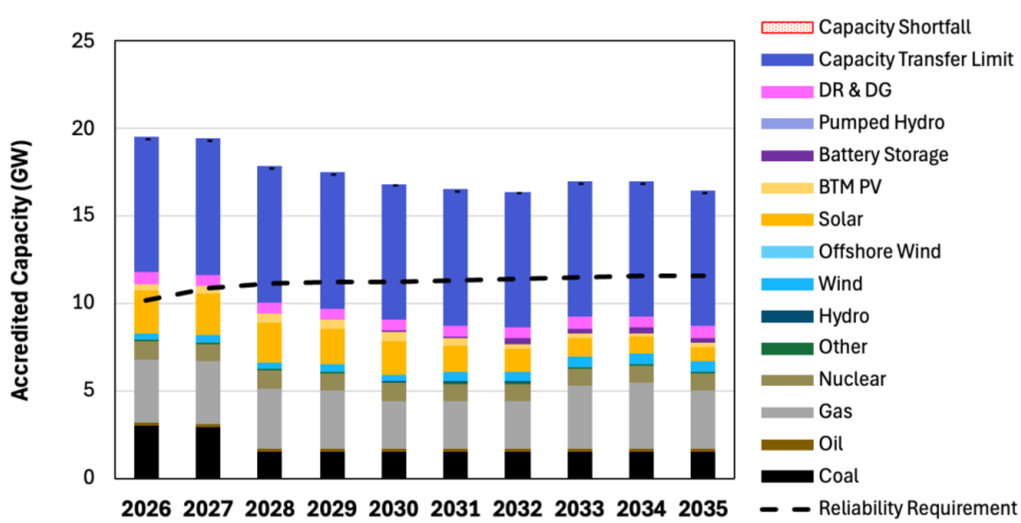


Figure 4-43: Illinois MISO LRZ 4 RA Balance (2026-2035) | Delayed Resource Additions



Building on the resource development timeline delays, this next outlook in the analysis also considers the effect of delaying the retirement of in-state generators, essentially extending the retirement date beyond those assumed to occur to comply with CEJA.

The resulting impact on Illinois' zonal outlook is modest, as illustrated in Figure 4-44 and Figure 4-45. In the ComEd zone, the previously projected shortfall is mitigated in this scenario until 2035, though the zone continues to rely on imports from PJM which has a shortfall risk. In MISO LRZ 4, the zone continues to rely on imports through its ZIA in 2028 through 2035. Overall, these in-state retirement deferrals have a modest impact on the physical resource adequacy picture, particularly given the persistent system-wide shortfall across both PJM and MISO.

Figure 4-44: Illinois PJM Zone RA Balance (2026-2035) | Delayed Resource Additions and Retirements

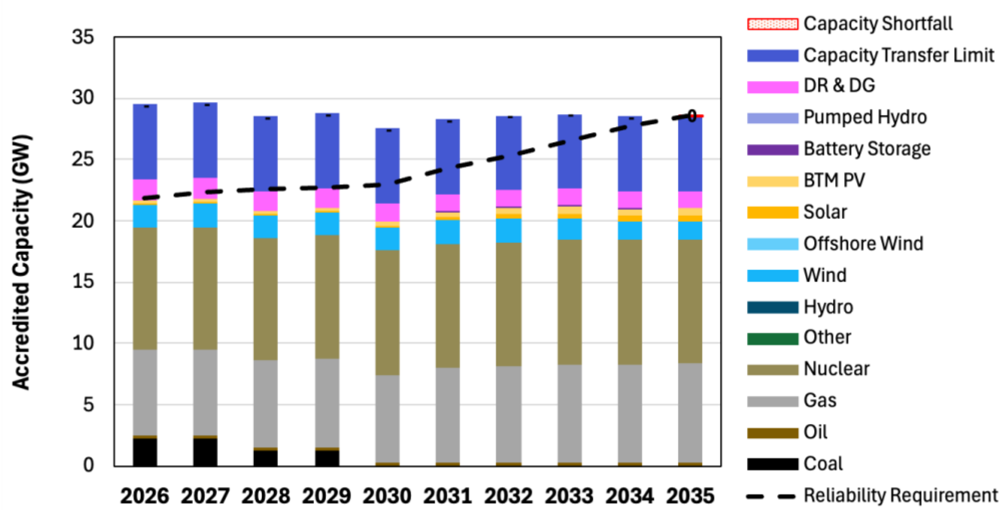
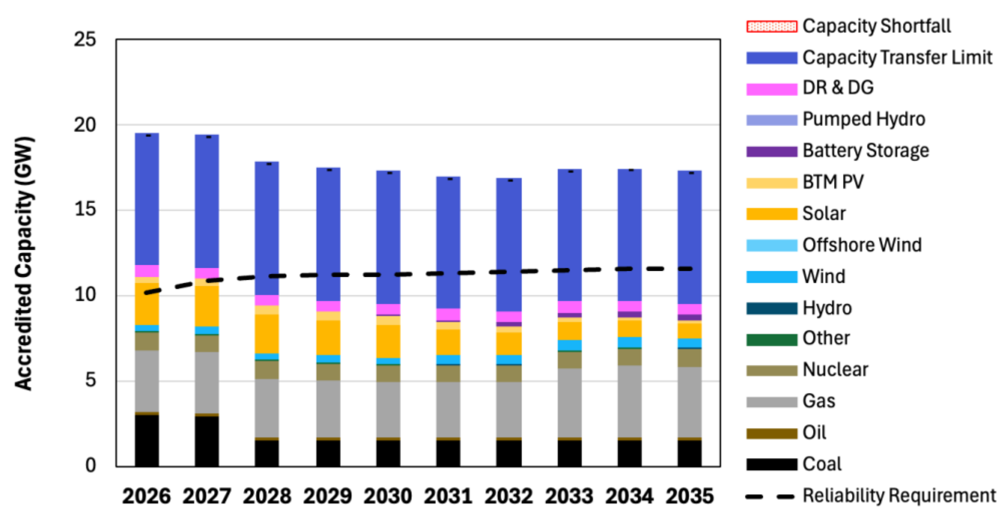


Figure 4-45: Illinois MISO LRZ 4 RA Balance (2026-2035) | Delayed Resource Additions and Retirements



4.2.6. Conclusions from the Resource Adequacy Balance Projections

Taken together, the resource adequacy balance projections indicate that Illinois faces a resource adequacy shortfall risk over the coming decade—not because the local zones are structurally deficient under baseline assumptions, but because both PJM and MISO are projected to face sustained system-wide capacity shortfalls in the absence of additional new resource development.

Across the scenario outlooks in the two major Illinois zones (and not accounting for the state of resource adequacy RTO-wide), the ComEd zone maintains adequacy into the early 2030s, while MISO LRZ 4 remains nominally sufficient through 2035. However, both zones become increasingly dependent on imports from their respective RTOs to meet resource adequacy requirements, and those imports cannot be relied upon when the broader RTO pool is short.

Under more realistic development timelines that incorporate delays in bringing new resources online, both zones experience tighter conditions, and MISO LRZ 4 becomes consistently reliant on its ZIA to balance supply and demand. Further, if retirements of fossil generators assumed to occur in compliance with CEJA were deferred—such as non-EJ zone plants with assumed retirement dates prior to 2035—any incremental capacity made available would only modestly and conditionally improve Illinois' resource adequacy balance and would not, on its own, mitigate the risk of a resource adequacy shortfall. Under certain modeled conditions, such deferrals may reduce the magnitude of projected shortfalls, but they do not alter the underlying drivers of risk. Moreover, any adjustment to assumed in-state retirement timelines must be evaluated within the broader regional context, as Illinois' resource adequacy remains fundamentally constrained by the availability—or scarcity—of surplus capacity across PJM and MISO.

Under scenarios in which the RTOs experience earlier and deeper shortfalls because of resource delays, Illinois consumers face elevated risks of capacity price spikes, transmission constraints, and potential loss-of-load events. These findings underscore that statewide reliability cannot be evaluated in isolation and that Illinois' future resource adequacy depends critically on timely resource development, regional market conditions, and coordinated planning across the broader PJM and MISO systems.

5. Long-Term Projection of Illinois Electricity Sector

5.1. Long-Term Planning for the Illinois Electricity Sector

5.1.1. Design Framework & Approach

The previous chapter focused on near-term resource adequacy conditions using supply and demand projections based on known resources. This chapter shifts focus to a longer-term perspective to explore how Illinois and the broader RTO systems might maintain reliability through 2045 under continued load growth and decarbonization policies along with changing resource economics. In contrast to the Resource Adequacy Balance model, discussed in Chapter 4, which evaluates whether anticipated changes in electricity supply are sufficient to meet demand, this chapter uses capacity expansion modeling to identify the quantity of additional effective capacity needed to ensure system reliability over time. A loss-of-load probability model is also used to project resources' ELCCs into the future as an input to the portfolio analysis and to ensure that the selected portfolios meet the RTO's reliability standard of a 1-day-in-10-year loss of load expectation. While not the full weighing of alternatives across a broad set of state policy priorities that an Integrated Resource Planning process would provide, this modeling approach identifies least-cost, policy-compliant long-term portfolios that help inform near-term decisions around resource adequacy in the context of future system dynamics and requirements.

The modeling framework implemented for this study relies on the interplay between capacity expansion and resource adequacy models:

Resource Adequacy: RECAP[179] identifies total effective capacity needed for resource adequacy and evaluates each resource's contribution towards meeting that need through extensive simulations of load and weather conditions.

Capacity Expansion: PLEXOS[180] is used to optimize generation and transmission portfolios to minimize cost while satisfying policy and resource adequacy constraints.

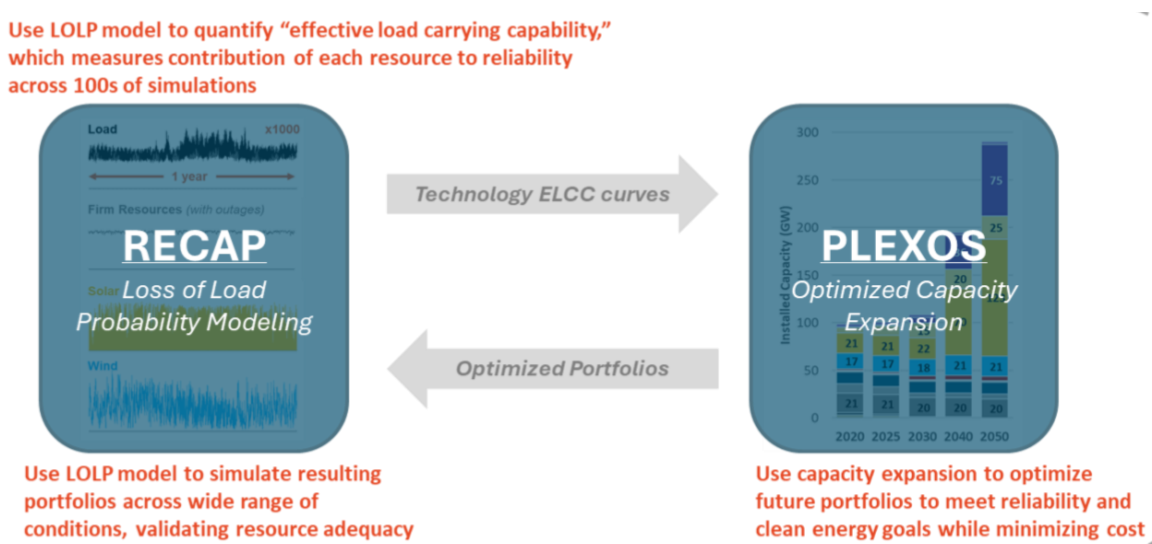
---

[179] RECAP is E3's in-house loss-of-load probability (LOLP) model; it has been used by utilities and system operators across North America. For more information, see: https://www.ethree.com/tools/recap-renewable-energy-capacity-planning-model/

[180] PLEXOS is a commercially available capacity expansion and production simulation modeling software developed by Energy Exemplar; it is used by utilities and system operators across North America, and it is the model currently used by MISO and PJM. For more information, see: https://www.energyexemplar.com/plexos

Figure 5-1 illustrates the interaction between these models. RECAP calculates Total Reliability Need (TRN) and Planning Reserve Margin (PRM) values that ensure sufficient effective capacity is built in each market, along with market- and technology-specific curves that relate the marginal Effective Load Carrying Capabilities of each resource type to its total penetration (expressed in MW) in the system. These curves are then used to constrain the PLEXOS model's resource selection to meet the TRN in each market and each projection year at the lowest total cost. Because these constraints can only approximate the complex system dynamics that feed into systemwide resource adequacy, we then use RECAP to stress-test the portfolios under thousands of simulated weather years based on historical conditions to confirm adequacy. Together, these models ensure portfolios are cost-optimal, reliable, and compliant with policy constraints. The same models and assumptions are also used in the Illinois 2025 Draft REAP, ensuring analytical consistency between the two studies which have complimentary focus and objectives. This is also the same fundamental modeling framework used in most Integrated Resource Planning processes across North America, including those supported directly by E3.

Figure 5-1: Electric System Modeling Approach with Resource Adequacy Considerations



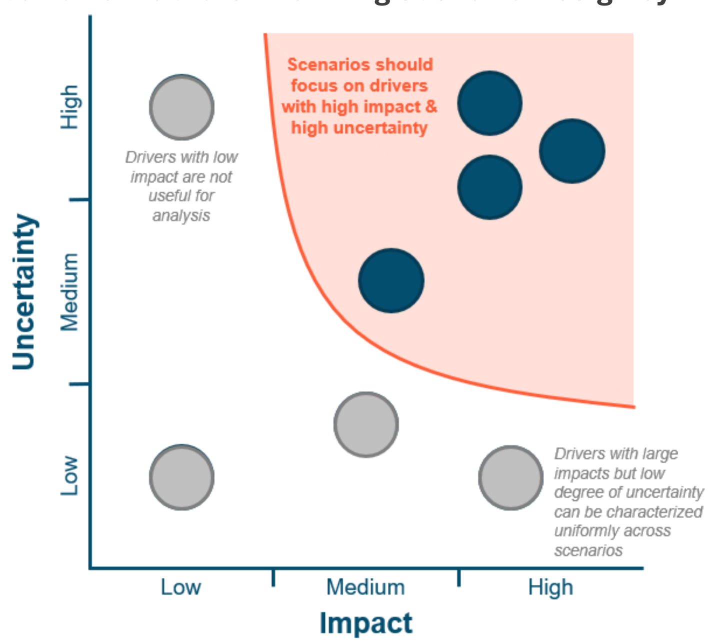
This modeling framework enables a rigorous evaluation of how resource adequacy can be maintained over the long term, as system demand grows and the resource mix shifts. By simulating forward-looking portfolios under various scenarios and testing their ability to meet resource adequacy standards, the analysis provides insight into the types and quantities of resources that may be required to avoid resource adequacy shortfalls, particularly beyond what is already planned or in the interconnection queue. The modeling framework also highlights effective capacity and transmission needs that can inform future policy development, investment priorities, and engagement in regional planning processes. Its iterative structure allows for future updates as technology costs and availability evolve, new policies emerge, or system conditions change which ensures the state can remain well-equipped to meet both reliability and decarbonization goals.

5.1.2. Scenario & Sensitivity Matrix

Evaluating resource adequacy requires understanding how system conditions may evolve under uncertainty. While the near-term load and resource balance focused on resource adequacy under known (yet variable) supply and demand trajectories, long-term outcomes are shaped by a wider band of uncertainty around policy implementation and achievement, fossil generation retirements, load growth, and technology advancement and costs. To capture a wide range of possible futures, this study uses a scenario framework to evaluate how these uncertainties impact system reliability and the types of resources needed to maintain resource adequacy over time.

Scenarios are designed to test high-impact, high-uncertainty drivers—those most likely to alter the capacity mix or challenge the system's ability to meet reliability standards, as illustrated below.

Figure 5-2: Classification of Factors Informing Scenario Design by Impact and Certainty



In this study, four key scenario drivers were identified and applied in different combinations to create six modeling cases. Three policy drivers reflect different policy decisions that Illinois could make that would directly impact the forecasted RA needs and eligible new resource options, while the fourth driver reflects uncertainty in new battery storage costs.

Table 5-1: Scenario Drivers Modeled

Scenario Driver	When included	When excluded
New Illinois Gas Allowed	New gas combustion resources are allowed to be developed in-state	No new gas resources can be constructed in Illinois
CEJA Extension	Thermal plant retirements under CEJA emissions standards do not occur by 2045[181]	Thermal plant retirements under CEJA occur as scheduled
Illinois Net Zero Emissions	Illinois must achieve net-zero carbon emissions by 2045[182]	Illinois does not have a 2045 net zero emissions target
Low Battery Costs	Lower costs for new battery storage projects are assumed	Base costs for new battery storage projects are assumed

These scenario drivers are used to define six modeling cases, inclusive of four scenarios and two sensitivities. The four scenarios are designed to allow detailed assessment and comparison of the two major policy drivers that Illinois faces: allowance of new in-state gas and extensions to the CEJA-driven fossil generator retirement schedules. Two sensitivities to the Base Case are defined to explore how a net-zero carbon emission target or lower trajectory battery storage costs would impact the selected resource portfolios.

Table 5-2: Scenario Matrix

Modeling Cases	New Illinois Gas Allowed	CEJA Extension	Illinois Net Zero Emissions	Battery Costs
Base Case	Yes	No	No	Base
CEJA Extension	Yes	Yes	No	Base
No New Illinois Gas	No	No	No	Base
CEJA Extension, No New Illinois Gas	No	Yes	No	Base
Illinois Net Zero	Yes[183]	Yes	Yes	Base
Low Battery Costs	Yes	Yes	No	Low

[181] Age-driven projected retirements in Illinois still occur as planned.
[182] Net-zero emissions are achieved by requiring all in-state gas generation to convert to a zero-carbon fuel by 2045, as well as requiring Illinois to be a net exporter of energy in 2045.
[183] New combustion equipment can still be selected, but all in-state gas generation is assumed to run on zero-carbon fuels by 2045.

The Base Case serves as a central reference point, reflecting a continuation of current law and development trends. Other cases apply combinations of scenario drivers to examine how Illinois state policies (such as extending fossil generator retirement dates assumed for CEJA compliance or disallowing new in-state gas generation), meeting deeper decarbonization targets, and low battery cost trajectory affect system outcomes.

These scenario combinations are intentionally designed to isolate the effect of each assumption, as well as how overlapping policies and trends compound or mitigate resource adequacy challenges. The results are used to identify cost-optimal portfolios and to understand how those portfolios maintain system adequacy under a range of future conditions.

5.2. Analytical Framework & Methodology

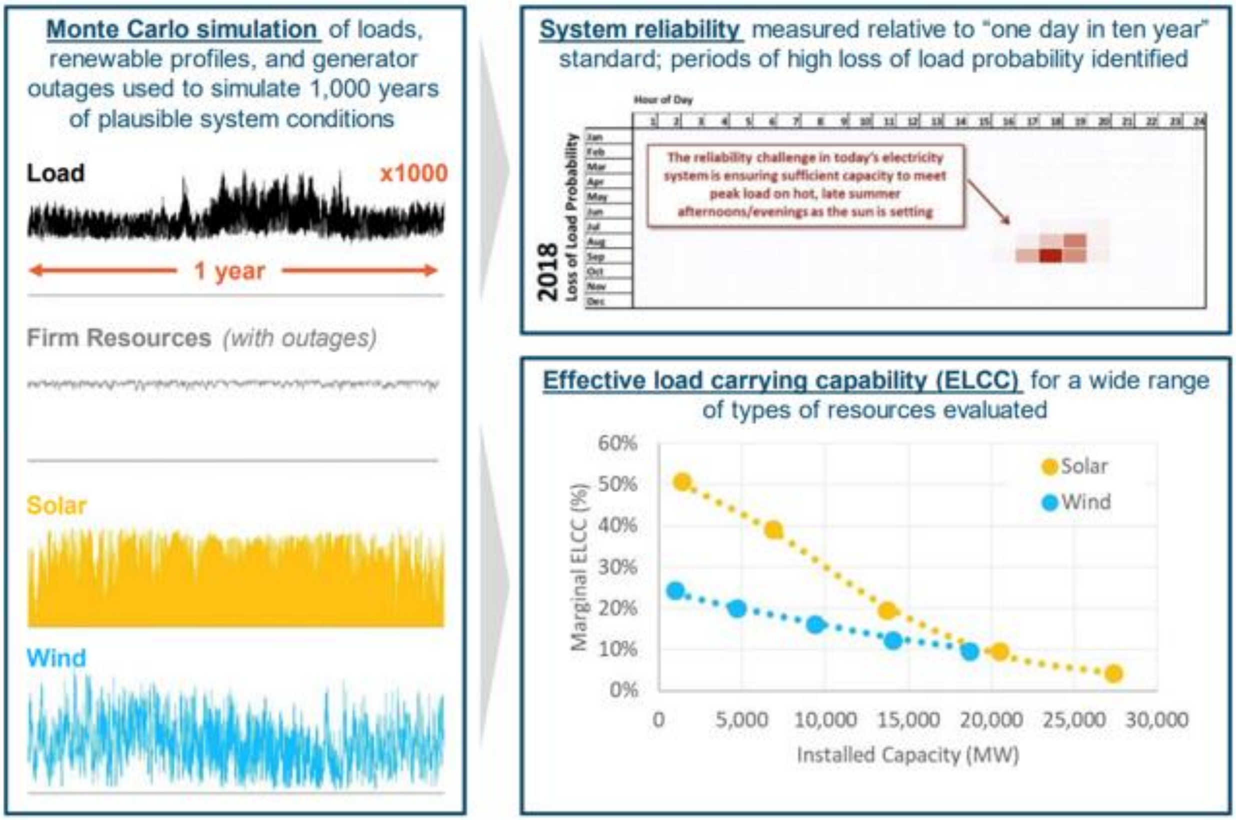
5.2.1. Loss of Load Probability Modeling

E3 used our Renewable Energy Capacity Planning Model (RECAP) to calculate reliability, ELCCs, and PRM targets in MISO and PJM. RECAP evaluates resource adequacy through time-sequential simulations of thousands of model-years of plausible system conditions to calculate a statistically significant measure of system reliability metrics as well as individual resource contributions to system reliability. The modeling framework, illustrated in Figure 5-3, is built around capturing correlations among weather, load, and renewable generation, while simulating generator outages stochastically, capturing realistic renewable generation, simulating time sequential dispatch of energy limited resources, and capturing a diverse range of load conditions.

Both PJM and MISO determine their resource accreditation using LOLP[184] models that evaluate a diverse array of load conditions, resource performance, and a time sequential dispatch of energy limited resources. RECAP, PJM's RRA model, and MISO's SERVM model all meet industry practice and capture loss of load probability.

[184] PJM uses in-house RRA model and MISO uses Astrape's SERVM model.

Figure 5-3: E3 RECAP Framework



5.2.2. Capacity Expansion Modeling

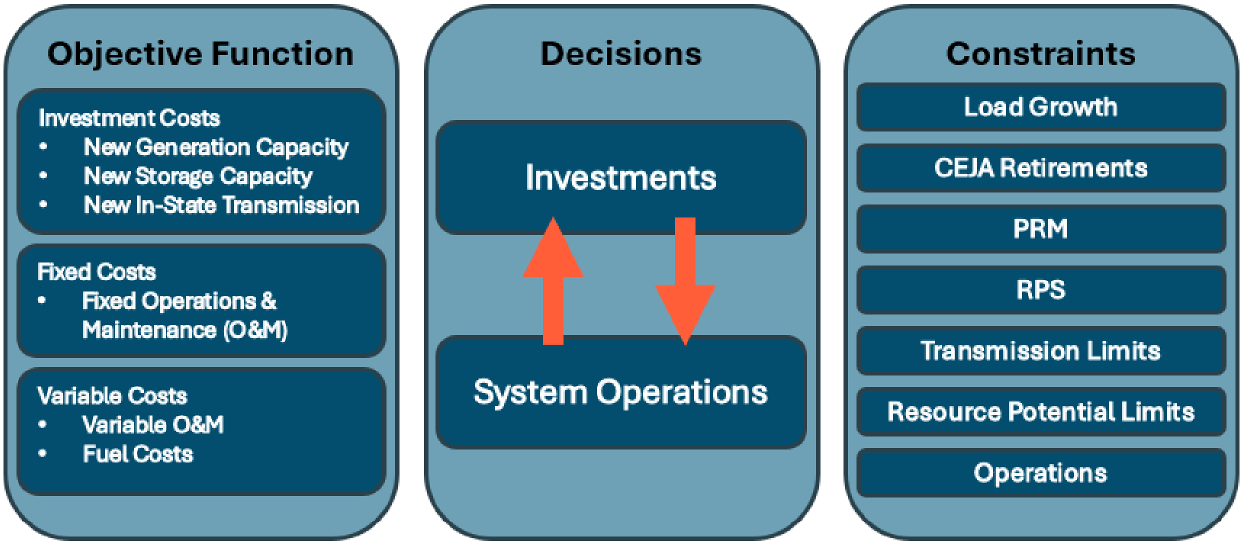
To optimize the long-term resource portfolios required to meet future load growth and policy goals, capacity expansion modeling is performed using PLEXOS.[185] PLEXOS is an electricity system capacity expansion model that identifies the least-cost long-term combination of generation investments, subject to reliability, policy, and operational constraints. PLEXOS considers investment costs, fixed costs, and production costs to simultaneously optimize long-term capacity expansion and dispatch decisions. This allows the model to directly capture dynamic trade-offs between investments and dispatch, such as energy storage investments versus renewable curtailment and/or overbuild. PLEXOS also captures the reliability contributions of all resources towards satisfying its reliability constraint.

Figure 5-4 provides an overview of the PLEXOS model, including the objective function, key model decisions, and key constraints.

---

[185] PLEXOS is a commercially available software package from Energy Exemplar for electricity system modeling. PLEXOS LT ("long-term") is the planning phase of PLEXOS used for capacity expansion modeling.

Figure 5-4: Overview of the PLEXOS Model



5.2.3. System Topology

The PLEXOS model utilizes the system transmission topology of the MISO and PJM RTOs with carve-outs in Illinois to separately represent Ameren Illinois and the cooperatives or municipalities in MISO's LRZ 4, as well as ComEd and the cooperatives or municipalities in PJM's ComEd zone. Other Illinois load serving entities or municipalities are aggregated into the regions they reside, such as MidAmerican in MISO's LRZ 3 and Jo Carroll Energy Cooperative in MISO's LRZ 1. The system representation is shown in Figure 5-5. Each zone contains the load and resources attributable to the LSEs within the zone and reflects existing and planned interregional transmission between neighboring zones. Transmission representation is informed by EIA hourly electric grid monitor,[186] MISO 2024 LOLE Study Reports,[187] MISO Transmission Expansion Plan (MTEP) 2024,[188] PJM Regional Transmission Expansion Plan (RTEP) 2024[189] and MISO's Tranche 1 and 2.1 reports[190] under the Long-Range Transmission Planning process. This zonal representation enables the model to

---

[186] EIA Grid Monitor: https://www.eia.gov/electricity/gridmonitor/dashboard/electric_overview/US48/US48

[187] MISO 2024 LOLE Study Report: https://cdn.misoenergy.org/PY%202023-2024%20LOLE%20Study%20Report626798.pdf

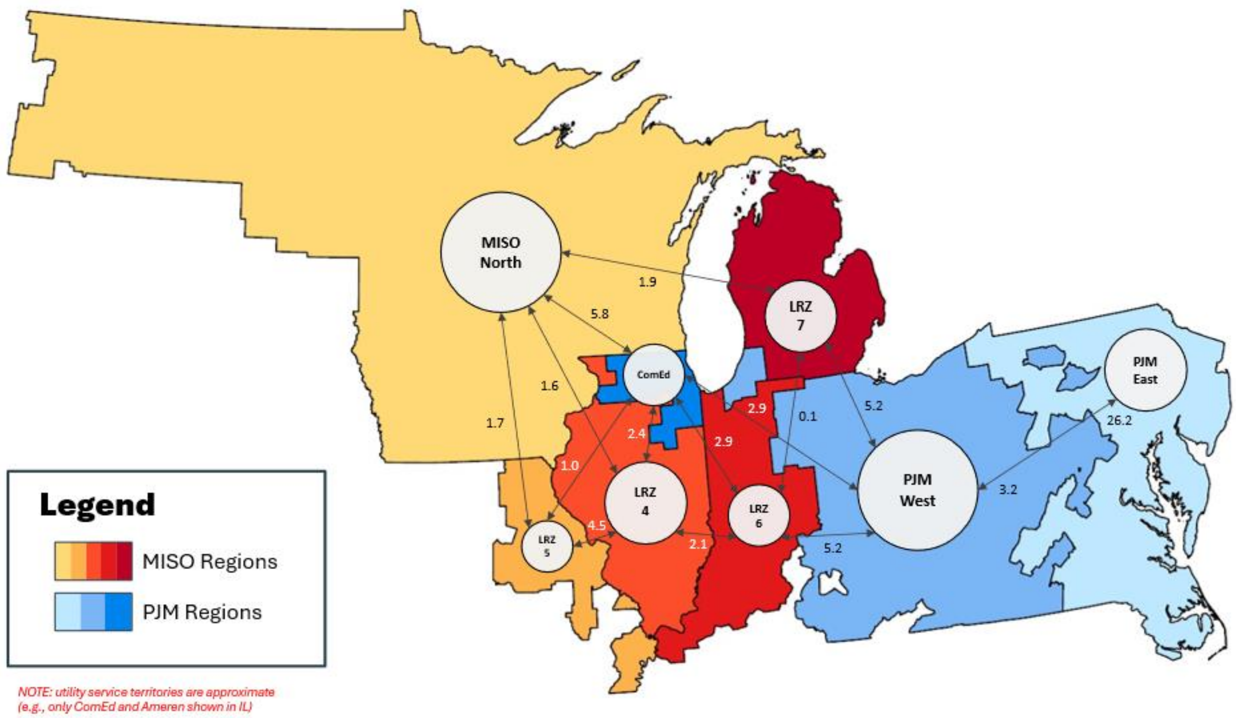
[188] MISO MTEP: https://cdn.misoenergy.org/20241001%20PAC%20Item%2002%20MTEP24%20Report%20Preview650567.pdf

[189] PJM RTEP 2024: https://www.pjm.com/-/media/DotCom/committees-groups/committees/teac/2025/20250304/20250304-2024-rtep-window-1-reliability-analysis-report.pdf

[190] MISO (Long Range Transmission Planning) LTRP projects: https://www.misoenergy.org/planning/long-range-transmission-planning/

simulate transmission-limited power exchanges while maintaining computational tractability for long-term capacity expansion modeling. The PLEXOS model does not include representation of MISO's LRZs 8, 9, or 10 ("MISO South") because this region has more limited transmission interconnection with other zones and historically it has been a net exporter into MISO North/Central. To maintain a conservative modeling approach, MISO South and its projected future capacity needs were not represented in PLEXOS for this study.

Figure 5-5: PJM and MISO Transmission Topology modeled in PLEXOS (2030)



5.3. Input Development

5.3.1. Long-term Scenario Load Forecasts

5.3.1.1. Load Forecasting Methodology

E3's long-term load forecasting methodology for this study occurs in three distinct steps. First, the baseline forecasts of annual energy and peak demand are collected directly from the RTOs and utilities—including the PJM Long-Term Load Forecast Report,[191] MISO's Long-

[191] 2025 PJM Long-Term Load Forecast Report (January 24, 2025): https://www.pjm.com/-/media/DotCom/library/reports-notices/load-forecast/2025-load-report.pdf

Term Load Forecast Report,[192] and the IPA Long-Term Plan.[193] Second, E3 refines these forecasts where necessary to align with the most current utility-level data and industry expectations. Finally, underlying hourly load shapes linked to a model weather year are developed that account for the annual contributions of individual major load components (e.g., base load, electric vehicles, data centers). The culmination of these components results in a comprehensive hourly load forecast.

5.3.1.2. Modifications to RTO Forecasts

To ensure consistency and realism in long-term planning, E3 applied a limited number of adjustments to the RTO forecasts:

1. **Updated Zonal Forecasts Based on Utility Data**: For Illinois zones (ComEd zone and MISO LRZ 4), the study uses updated utility-provided forecasts as provided in the IPA Long-Term Plan[194], which incorporate more up-to-date data than those originally provided to and embed in the RTO forecasts.
2. **Adjustments to PJM Data Center Load Growth Trajectory**: PJM's long-term forecast assumes that current levels of high data center growth continue through 2045. E3 retains PJM's near-term assumptions through 2030 but moderates the trajectory thereafter, tapering the annual growth rate from ~14% to 1% by 2040. This reflects an assumption that current demand growth—driven largely by generative AI—will eventually stabilize due to market saturation, infrastructure constraints, and ongoing efficiency improvements. This assumption is informed by historical load trends, facility-level development data from sources including DataCenterMap,[195] CBRE,[196] Baxtel,[197] JLL,[198] and EPRI,[199] and broader analysis of U.S. electricity demand. Importantly, this adjustment should be seen as a optimistic input to the analysis from the perspective of resource adequacy. Any scenario with higher data center growth, such as that projected by PJM's current baseline, would result in greater resource adequacy shortfalls and increase the need for new reliable

---

[192] MISO Medium and Long-Term Load Forecast (December 18, 2024): https://www.misoenergy.org/events/2024/medium-and-long-term-load-forecast---december-18-2024/
[193] IPA Long-Term Renewable Resources Procurement Plan (October 20, 2025): https://ipa.illinois.gov/renewable-resources/long-term-plan.html.
[194] Ibid.
[195] Data Center Map: https://www.datacentermap.com/.
[196] CBRE: North America Data Center Trends H1 2025: https://www.cbre.com/insights/reports/north-america-data-center-trends-h1-2025.
[197] Baxtel, https://baxtel.com/data-center/united-states
[198] JLL: North American Data Center Report Midyear 2025: https://www.jll.com/en-us/insights/market-dynamics/north-america-data-centers.
[199] EPRI: Analyzing Artificial Intelligence and Data Center Energy Consumption: https://www.epri.com/research/products/3002028905.

capacity. Additional justification and supporting evidence for the study team's assumptions are provided in section 5.3.1.3.

3. **Exclusion of Specific Load Components in MISO load projections**: MISO's Current Trajectory scenario includes load growth projections from green hydrogen production and industrial development spurred by the Inflation Reduction Act. Given uncertainty around policy feasibility and actual demand realization, these loads were excluded from this study's base assumptions. All other MISO load drivers, including data centers, are retained consistent with MISO's forecast.

Although the study forecasts are derived from and align closely with RTO and utility forecasts for total annual energy and peak demand, differences in *net* peak demand can emerge due to differences in modeling methodology. In this study, hourly load profiles are generated for each zone using E3's weather-normalized neural network regression approach, tied to each year's expected annual peak and energy total. The load profiles, in conjunction with differences in underlying behind-the-meter normalized hourly profiles, will differ from RTO assumptions.

These modeling differences lead to slight variations in net peak timing and magnitude compared to RTO-reported values, particularly when assessing reliability hours and capacity needs. These variations are expected and appropriate for integration into hourly models such as PLEXOS and RECAP, which require internally-consistent, weather-aligned load and generation profiles.

5.3.1.3. Data Center Load Forecast Discussion

E3's long-term data center forecast is based on RTO published data along with Illinois utility forecasts. From the baseline assumptions, adjustments are incorporated to the long-term data center forecast to account for an anticipated substantial moderation in data center load growth following the current short-term expansion. This projection is grounded in E3's analysis of the structural constraints, technological factors, and historical trends that shape data center development described below. This forms the basis for E3's utilization of PJM's near-term assumptions for data center load growth through 2030 but a moderation thereafter, tapering the annual growth rate from ~14% to 1% by 2040.

Historical evidence further supports the characterization of data center development as a recurring "boom-slow" cycle. The boom of the early 2000s was followed by a prolonged period of modest growth: total load increased by 90 percent from 2000–2004, by 24 percent from 2005–2010, and by 4 percent from 2010–2014.[200] Analysts writing in 2016 projected

---

[200] Berkeley Lab United States Data Center Energy Usage Report: https://eta-publications.lbl.gov/sites/default/files/lbnl-1005775_v2.pdf.

continued deceleration through 2020, including the possibility of negative growth under certain efficiency assumptions. E3 assesses that continued efficiency gains from building larger facilities,[201] implementing liquid cooling systems,[202] and ongoing chip improvements[203] will continue to apply downward pressure on data center load growth. Consistent with this pattern, E3 forecasts that the United States is currently in the midst of another boom phase that will eventually transition to a slow-growth period.

Hence, E3's near- to mid-term data center forecasts for PJM and MISO are initially based on RTO forecasts, confirmed by facility-level data of known and announced facilities provided by DataCenterMap,[204] and further shaped by data from CBRE,[205] Baxtel,[206] JLL,[207] and EPRI.[208] This informs E3 view on current load and expected additions over the next 6-8 years. Based on the expectation of market saturation, E3 then attenuates the growth towards a long term growth rate. The 10-year period of attenuation and 1% year over year long term growth rate are aligned with historical trends from the 2000-2014 period.

Adjustments to data center forecasts discussed has primarily centered around PJM's forecasts. MISO is also experiencing significant data center interconnection requests and forecasts large load growth in the near-term (500% growth of data center loads between 2025 and 2030 and an average of 10% year over year growth between 2030 and 2040).[209] However, compared to E3's adjustment of PJM's forecast, E3 did not apply an additional haircut to MISO's forecast because MISO already assumes a 41% attrition rate on announced capacity of data centers.

While the PJM baseline data center forecast is scaled back in the 2030s, E3 incorporated incremental data center load additions to reflect projected data center load growth in ComEd that has been forecasted by the utility but not yet reflected in the RTO forecast. ComEd expects rapid data center load growth in the 2030s with data center growth

---

[201] The Uptime Institute: Large data centers are mostly more efficient: https://journal.uptimeinstitute.com/large-data-centers-are-mostly-more-efficient-analysis-confirms/.

[202] The Uptime Institute: 2024 Cooling Systems Survey: https://datacenter.uptimeinstitute.com/rs/711-RIA-145/images/2024.Cooling.Survey.Report.pdf.

[203] IEA: Efficiency improvement of AI related computer chips, 2008-2023: https://www.iea.org/data-and-statistics/charts/efficiency-improvement-of-ai-related-computer-chips-2008-2023.

[204] Data Center Map: https://www.datacentermap.com/.

[205] CBRE: North America Data Center Trends H1 2025: https://www.cbre.com/insights/reports/north-america-data-center-trends-h1-2025.

[206] Baxtel: https://baxtel.com/data-center/united-states.

[207] JLL: North American Data Center Report Midyear 2025: https://www.jll.com/en-us/insights/market-dynamics/north-america-data-centers.

[208] EPRI: Analyzing Artificial Intelligence and Data Center Energy Consumption: https://www.epri.com/research/products/3002028905.

[209] "Long Term Load Forecast," MISO, December 2024, https://cdn.misoenergy.org/MISO%20Long-Term%20Load%20Forecast%20Whitepaper_December%202024667166.pdf.

stabilizing by 2040. Similarly, E3 used MISO's forecast as the basis of its data center forecast only adding some incremental load to represent updates in Ameren's forecast. Similarly to ComEd, Ameren utility forecasts also reflected more amounts of data center growth that was not yet incorporated into RTO's forecast. E3 added the incremental amount of data center load to both its Ameren and MISO forecasts to reflect latest utility data.

1.1.1.1. Load Forecast Comparisons

The following figures compare net peak demand and annual load forecasts used in this study with those published by PJM and MISO to illustrate the dynamics described in sections 5.3.1.2 and 5.3.1.3. Additional detail on the load forecast is also included in Appendix F.

Figure 5-6: PJM Annual Load Forecast (GWh) and Peak Load Forecast (GW)

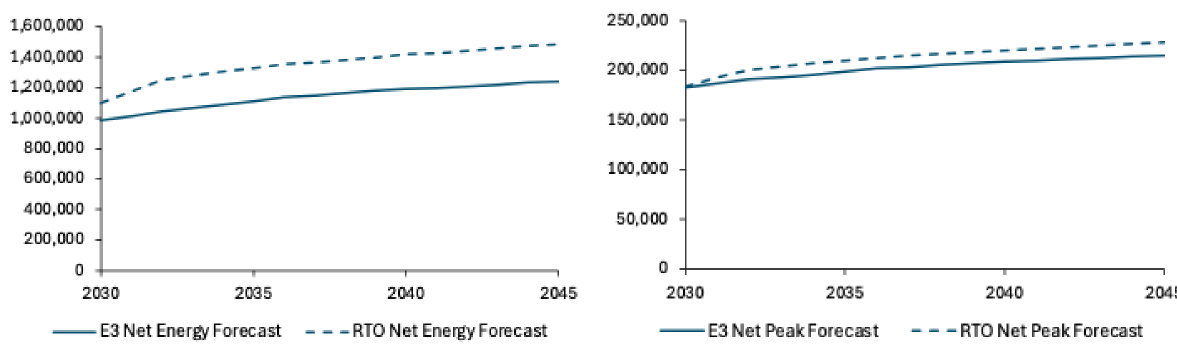


Figure 5-7: MISO Annual Load Forecast (GWh) and Peak Load Forecast (GW)

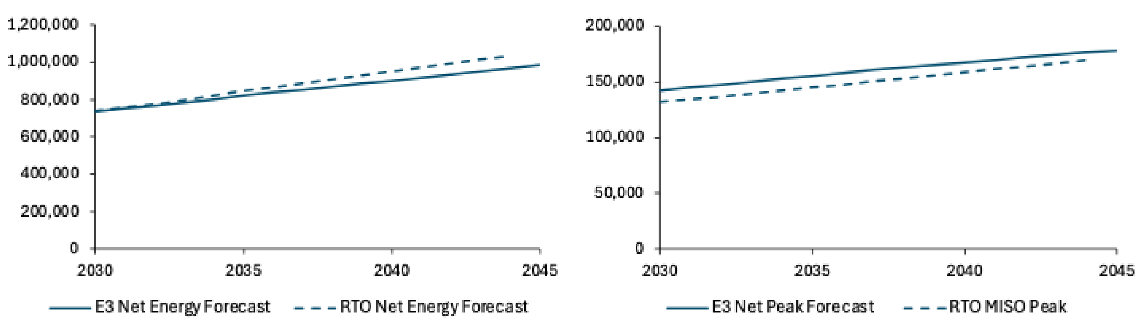


Figure 5-8: LRZ 4 Annual Load Forecast (GWh) and Peak Load Forecast (GW)

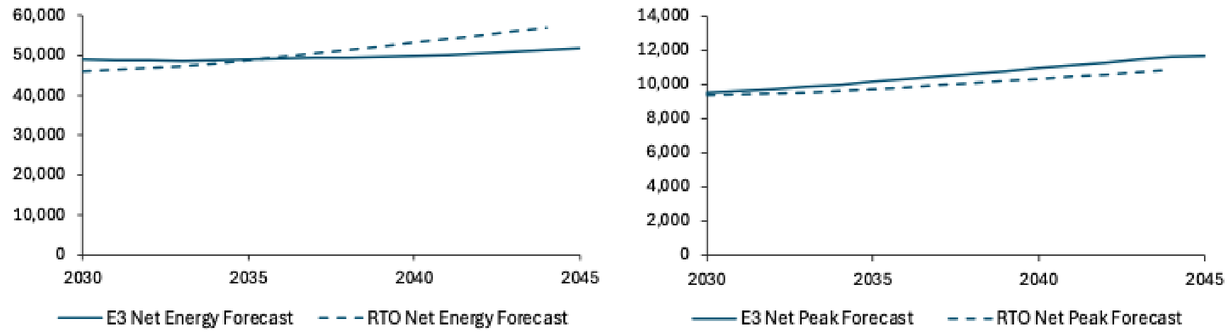
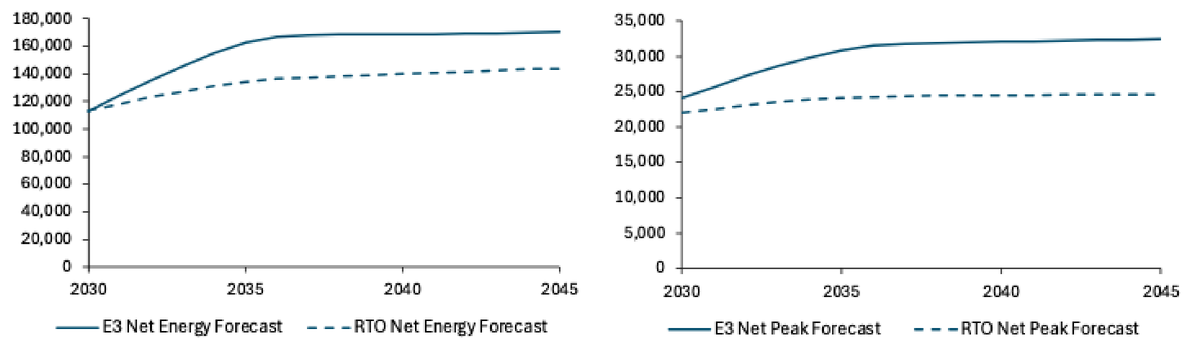


Figure 5-9: ComEd Zone Annual Load Forecast (GWh) and Peak Load Forecast (GW)



5.3.2. Hourly Profile Sources

E3 developed weather-correlated hourly profiles for both load and renewable generation across the regions studied. Load shapes were created using a neural network-based regression trained on recent historical data to capture the relationship between load and weather. While it is widely acknowledged that climate change will impact how weather patterns will deviate from historical norms in the future, the practice of incorporating the impacts of climate change into resource adequacy models and hourly profiles is still an emerging field and was not considered explicitly in this study. Profiles for load growth drivers—including data centers, building electrification, electric vehicles, and industrial electrification—were developed separately and layered onto the base load profile to preserve both weather correlation and the distinct load shape of each component. Renewable generation profiles for existing and candidate resources were similarly developed based on historical weather data, utilizing NREL's datasets. These time-synchronized load and generation profiles feed directly into the RECAP model for loss-of-load probability analysis and also inform the hourly inputs in the PLEXOS capacity expansion model.

5.3.3. Baseline Resources and Scheduled Retirements

In this study, the baseline resource portfolio is defined to include existing generation and storage resources, in-development and contracted resource additions, and scheduled resource retirements over the modeling horizon. The installed capacities of baseline resources are not optimized within PLEXOS—all additions and retirements are directly coded into the model as targeted inputs to ensure the additions and retirements are correctly represented. The Energy Exemplar 2024 PLEXOS Eastern Interconnect model was used as the starting point for this analysis and baseline (existing) generation resources were benchmarked and refined based on data from Hitachi Velocity Suite, S&P Global Capital IQ, and additional E3 research.[210]

Figure 5-10 presents the Illinois baseline installed capacity for all resource types over the 2030-2045 modeling horizon. The resources represented in this figure are only inclusive of those resources not selected by PLEXOS modeling, thus representing the baseline and not a derivative model scenario. The thermal capacity shown reflects projected coal retirements by 2030 based on announcements from plant owners in Illinois and additional retirements of oil and gas generators assumed to retire to comply with CEJA emissions requirements through 2045.[211] The increasing distributed solar capacity throughout the horizon reflects projected capacity additions aligned with Illinois programs as projected in the Illinois Power Agency's 2026 Long-Term Renewable Resources Procurement Plan filed for ICC approval on October 20, 2025.[212] Future utility-scale wind and solar additions needed to meet Illinois' renewable energy targets are not included in the baseline resources in Figure 5-10. These resources are instead modeled under the renewable portfolio standard (RPS) targets within the PLEXOS model and presented as part of the model's selected resource portfolios in section 5.4 of this report. More detail on how the RPS targets in the PLEXOS model are aligned with the IPA Long Term Plan is provided in section 5.3.8 and in Appendix F.

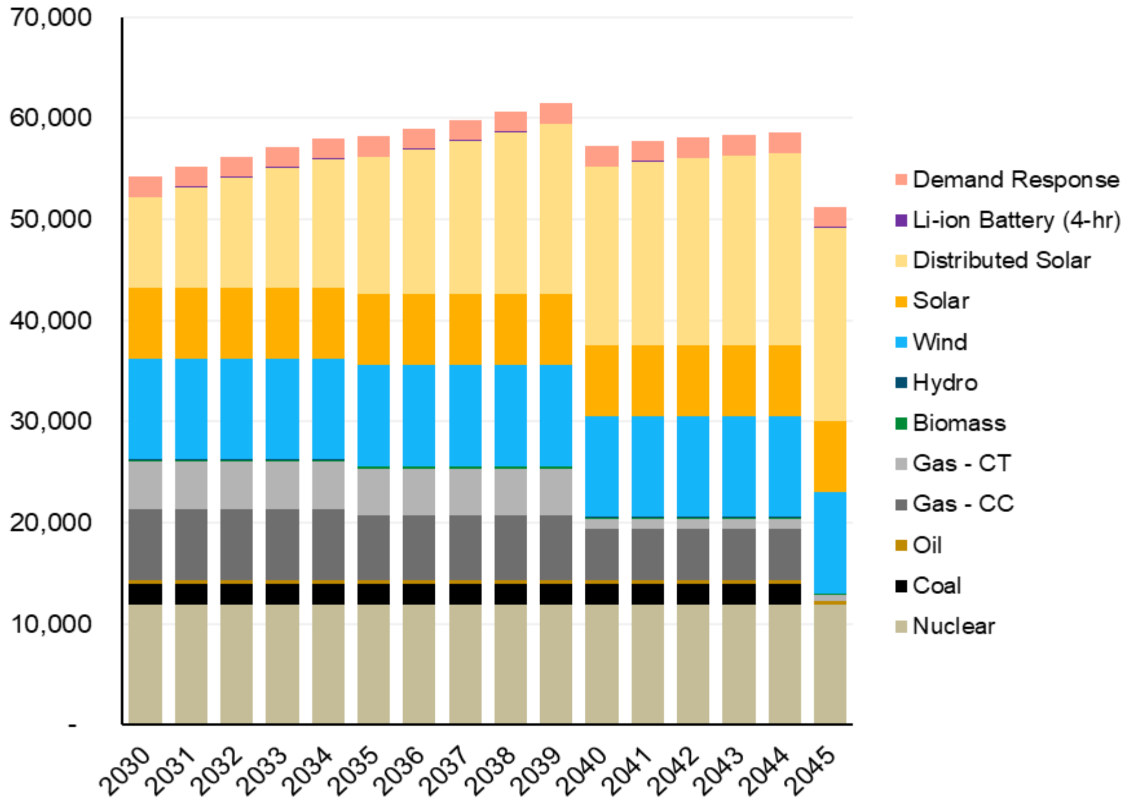
---

[210] The model database is made up of granular, unit-level resource assignments to each zone defined according to the system topology. These are typically assigned based on physical location but may also consider known contracted shares, where applicable and finely tracked.

[211] These are the default retirement assumptions for the Base case. In scenarios where the fossil generator retirements are extended, the baseline thermal capacity is flat through 2045.

[212] IPA 2026 Long-Term Renewable Resources Procurement Plan: https://ipa.illinois.gov/content/dam/soi/en/web/ipa/documents/20251020-2026-long-term-renewable-resources-procurement-plan.pdf

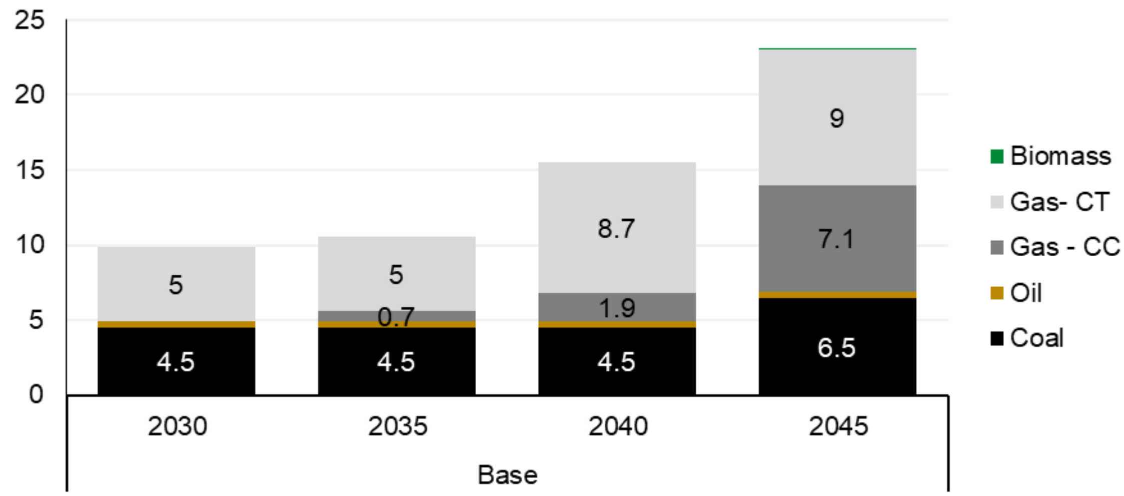
Figure 5-10: Illinois Baseline Installed Capacity (MW)



All units are instead assumed to retire by 2045 in cases where fossil generator retirements are modeled to occur to comply with CEJA as a conservative assumption and based on the current, uncertain future of the green hydrogen economy.

Figure 5-11 presents Illinois thermal capacity retirements assumed over the planning horizon. Under CEJA, all coal, oil, and natural gas facilities larger than 25 MW must reduce emissions to zero by 2045 or retire. In addition to retirements assumed to occur to comply with CEJA, 4,488 MW of projected coal retirements by 2030 are included in all cases, reflective of announced retirements that are set to happen regardless of whether an extension to CEJA is granted. While gas generating facilities in Illinois could opt to convert to 100% green hydrogen to comply with the law, all units are instead assumed to retire by 2045 in cases where fossil generator retirements are modeled to occur to comply with CEJA as a conservative assumption and based on the current, uncertain future of the green hydrogen economy.

Figure 5-11: Illinois Cumulative Retirements (GW)



While all fossil fuel generation in Illinois is scheduled to retire by 2045 or reduce emissions to zero under CEJA, the law also establishes interim emissions limits on existing thermal generators. Emissions restrictions apply to all generating units over 25 MW, with exact requirements varying by ownership structure and fuel type. Additionally, exceedances to the emissions restrictions are allowed in certain instances if the relevant RTO determines that the facility is necessary to maintain reliability, support local power flow requirements, or provide emergency backup services to the grid. These operational emissions restrictions are applied across all scenarios.

- **Privately Owned Generation:** Under CEJA, coal- and oil-fired generation in Illinois must reduce emissions to zero by 2030. Gas fired generation must reduce emissions to zero by 2045, with accelerated emissions reductions based on emissions intensity, proximity to certain population zones or equity investment eligible communities, and heat rates. Annual emissions caps are based on 2018-2020 levels, with compliance demonstrated through rolling 12-month average emissions.
- **Publicly Owned Generation:** CEJA sets different emissions requirements for thermal generators in Illinois owned by public electric service providers such as municipal utilities and electric cooperatives. These publicly owned coal- and oil-fired generators must reduce emissions by 45% by 2035, with a possibility extension to 2038, and to zero by 2045. Gas-fired generation must reduce emissions to zero by 2045 with no interim schedule.

5.3.4. Candidate Resources

Candidate resources represent the menu of new resource options from which PLEXOS can select to create an optimal portfolio. The candidate resources identified for this study primarily represent established, commercially proven technologies available today. The guiding principles used to determine whether a resource technology should be modeled in PLEXOS include:

- **Established**: The resource is an established commercialized technology in use today.
- **Scalable**: New builds of the resource could be realistically selected at sufficient volume to meaningfully impact Illinois' electric portfolio.
- **Economic**: This resource is projected to be cost-competitive within the timeframe of the modeling horizon, with sufficient publicly available market data to validate the projections.
- **Actionable**: Mechanisms currently exist, or could be developed under reasonable expectations, to enable the State to guide procurement of this resource.
- **Timely**: This resource could be developed within the timeframe of the modeling horizon with a reasonable degree of certainty.

The candidate resource technologies represented in PLEXOS are listed below. These resources are made available across all of the PLEXOS zones for selection to meet reliability, hourly demand, and policy requirements. Candidate resources within Illinois are represented within each of the REAP zones, which help reflect deliverability constraints and consider economic transmission upgrades, described in more detail in section 5.3.9 and Appendix F. It should be noted that transmission expansion as aligned with known transmission plans (i.e. MISO's MTEP[213] and PJM's RTEP[214]) but not offered to the model for economic selection.

To ensure consistency with CEJA, all new in-state gas resources modeled in Illinois are assumed to be hydrogen-ready and thus capable of achieving compliance with the law's zero-emission requirements by 2045. These hydrogen-ready resources incur a cost premium over conventional gas generators, reflecting expected technology upgrades and

---

[213] MISO MTEP: https://cdn.misoenergy.org/20241001%20PAC%20Item%2002%20MTEP24%20Report%20Preview650567.pdf.

[214] PJM RTEP 2024: https://www.pjm.com/-/media/DotCom/committees-groups/committees/teac/2025/20250304/20250304-2024-rtep-window-1-reliability-analysis-report.pdf.

fuel flexibility requirements. This premium is embedded in the cost trajectories shown further below.

Available candidate resource potential for new resources is based on NREL datasets; however, new nuclear is assumed to be constrained to 1 GW by 2035 and 3 GW by 2040 to reflect realistic project development timelines for this technology. All resources are available to be built starting in 2030, aside from new nuclear capacity which is first available in 2035. Certain scenarios also limit new gas availability.

- Hydrogen-ready combined-cycle gas turbines (CCGT)
- Hydrogen-ready combustion turbine (CT)
- Nuclear fission reactors
- Utility-scale solar photovoltaic
- Onshore wind
- 4-hour lithium-ion batteries
- Firm imports from out-of-state gas generators

Figure 5-12 presents Illinois-specific upfront capital expenditure (CapEx) forecasts for key generation and storage resources modeled, while Figure 5-13 and Figure 5-14 illustrate the levelized cost of energy and levelized fixed cost for applicable technologies, respectively. These projections are primarily based on the National Renewable Energy Laboratory's Annual Technology Baseline,[215] adjusted to reflect current market conditions. The trends illustrate both technological progress and inflationary effects over time. Key modeling assumptions include the sunset of current federal tariff impacts by 2030, expiration of solar and wind tax credits before 2030 (in line with the July 2025 budget reconciliation bill), ineligibility of battery storage for investment tax credits due to foreign content-based eligibility restrictions in current federal policy, and short-term gas turbine scarcity premiums that are assumed to normalize by 2035.

[215] NREL 2024 ATB: https://atb.nrel.gov/electricity/2024/data.

Figure 5-12: Illinois Candidate Resource Capital Expenditure (CapEx), Nominal $/kW

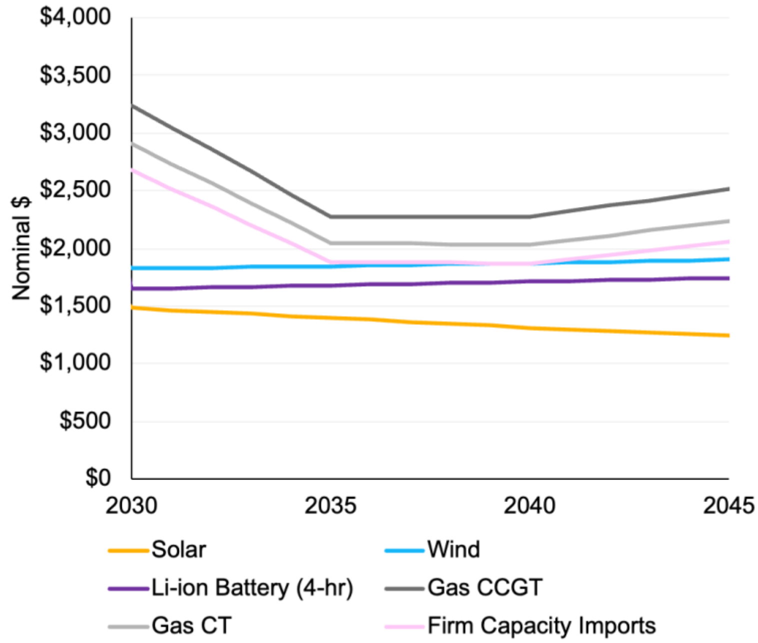


Figure 5-13: Illinois Candidate Resource Levelized Cost of Energy, Nominal $/MWh

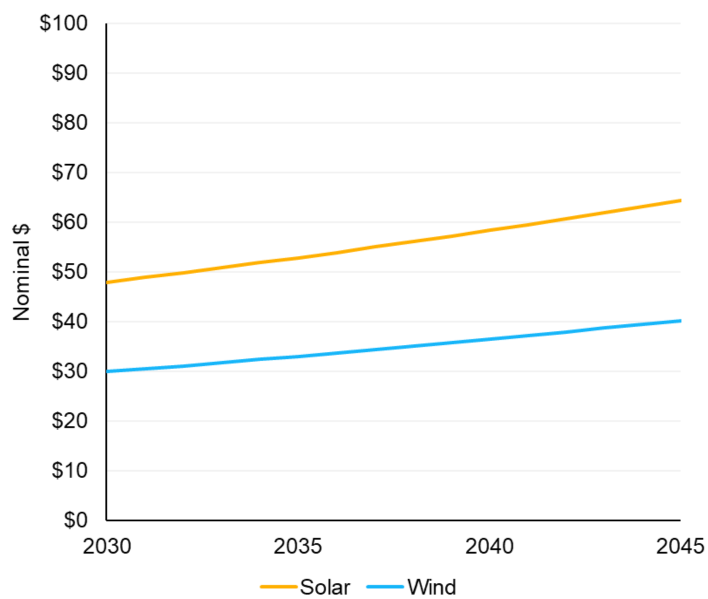
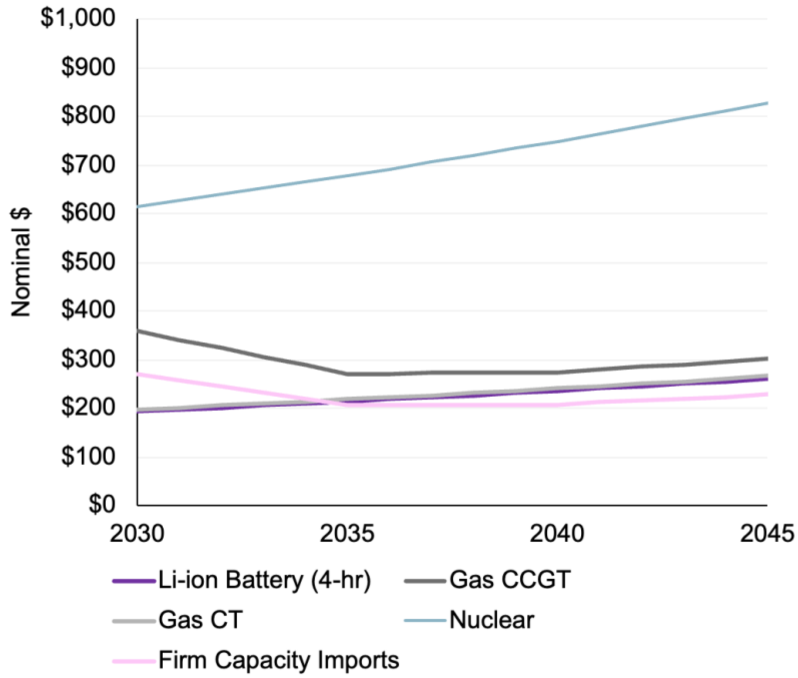


Figure 5-14: Illinois Candidate Resource Levelized Fixed Cost, Nominal $/kW-yr



5.3.5. Planning Reserve Margin (PRM)

E3 uses RECAP to calculate the PRMs applied in the PLEXOS capacity expansion model. These PRMs represent the minimum required capacity above projected gross peak load necessary to meet the industry-standard reliability threshold of 1-day-in-10-year (0.1 LOLE). While PJM and MISO each publish their own PRMs annually based on internal methodologies and inputs (i.e. MISO's DLOL[216] and PJM's FPR[217]), E3 calculates PRMs using RECAP to ensure alignment with the resource accreditation assumptions detailed in 5.3.6. This approach harmonizes both the numerator (effective capacity contributions from each resource type) and the denominator (required reserve margins) using a consistent modeling framework, which is critical for maintaining fidelity in the capacity expansion optimization process. While PJM, MISO, and E3 utilize different resource adequacy frameworks to calculate the 1-day-in-10-year LOLE target, the result of achieving the industry standard reliability requirement will be aligned.

[216] Planning Year 2025-2026 Indicative Direct Loss of Load (DLOL) results, MISO: https://cdn.misoenergy.org/PY%2025-26%20Indicative%20DLOL%20Results657893.pdf.

[217] 2025 PJM Effective Load Carrying Capability and Reserve Requirement Study, PJM: 2025-pjm-elcc-rrs.pdf.

To represent system reliability requirements, four capacity zones are modeled in PLEXOS: two RTO zones and two Illinois zones. The model footprint includes both MISO and PJM regions as external capacity zones to capture broader system reliability needs and interactions between the Illinois zones and the markets. All resources are assumed to provide capacity attributes for the zone in which they are physically located, except for firm capacity from thermal plants physically located in neighboring RTO regions but contracted to provide reliable capacity to Illinois utilities. Each reliability requirement is represented as a planning reserve margin percentage, detailed in Table 5-3.

Table 5-3: Modeled Planning Reserve Margin by Region (% of Gross Median Peak Load)

Region	PRM
PJM	7.5%
MISO	5.5%
ComEd Zone	8.3%
LRZ 4	5.8%

5.3.6. Effective Load Carrying Capabilities

E3 calculated ELCC values for this study using a methodology consistent with the core principles used by PJM and MISO—utilizing a LOLP model that measures resource performance during system-critical periods. While E3's ELCC methodology differs from PJM's MRIM and MISO's DLOL approach in its implementation, all three methods share a common foundation: measuring how resources contribute to system reliability during periods of peak risk. E3 calculates ELCCs based on changes in Loss of Load Expectation (LOLE), consistent with a 1-in-10-year reliability standard and applies these values within a unified framework for both accreditation and reliability need determination. This ensures that ELCCs and planning reserve margin (PRM) targets are harmonized.

Because long-term capacity expansion models must evaluate how ELCCs change as portfolios and load conditions evolve, ELCCs are not fixed inputs in PLEXOS. Instead, ELCC curves—which represent the marginal ELCC of a resource as a function of its penetration—are developed using the LOLP model and are passed into PLEXOS to ensure these dynamics are captured. This essentially allows PLEXOS to compare different resource types on a level playing field and select a cost-optimal portfolio that ensures the total reliability value of the portfolio is at least equal to the reliability requirement.

When discussing ELCCs, we will be referring to our calculation methodology which is determined based on the marginal change in LOLE. ELCC curves were produced for three resource types: wind, solar, and 4-hour storage, and for each of the 4 regions studied—MISO LRZs 1-7, PJM, MISO LRZ 4, and the ComEd zone—to capture the load-resource interactions unique to each region. ELCC curves produced for the four regions are shown Figure 5-15 through Figure 5-18. To confirm alignment with the RTOs, E3 conducted “apples-to-apples” comparisons to the RTO approaches, documented in Appendix F, and these show that E3’s ELCC values closely track those published by PJM and MISO.

Since MISO and PJM are significantly larger systems than the ComEd zone and LRZ 4 respectively, the ELCC degradation is slower (e.g., the marginal ELCC at 20 GW of total penetration for 4-hr storage is 60% in PJM but only 21% in the ComEd zone). Using ELCC curves specific to each of the 4 regions in PLEXOS ensures that the resource portfolios selected maintain both “local” reliability within Illinois zones and RTO-wide reliability.

Figure 5-15: PJM ELCC Curves

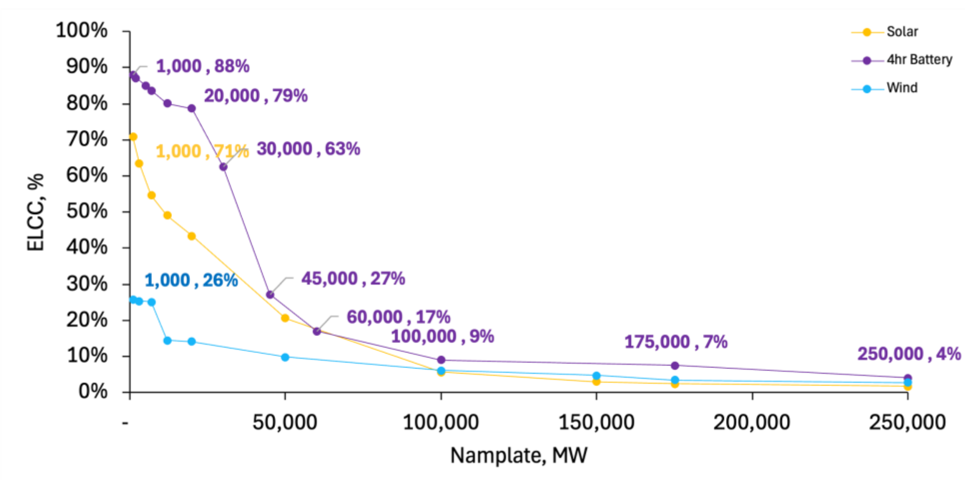


Figure 5-16: MISO LRZs 1-7 ELCC Curves

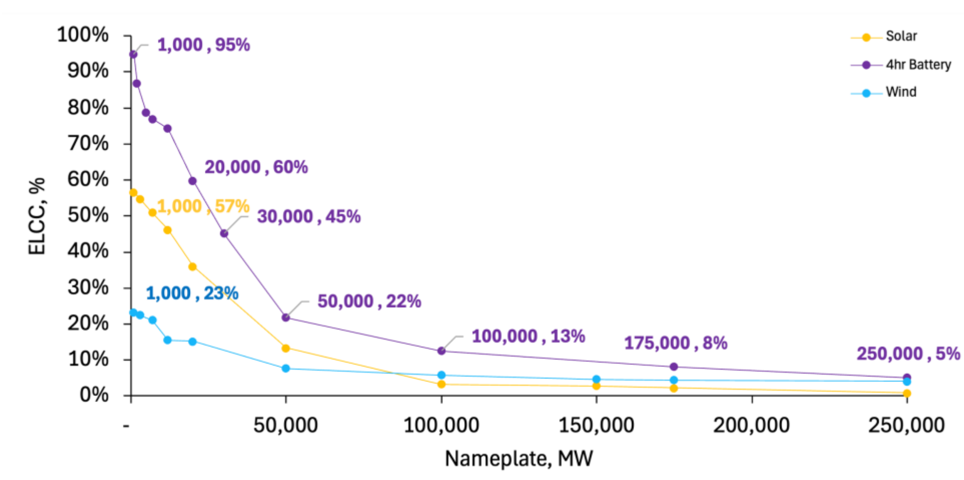


Figure 5-17: ComEd Zone ELCC Curves

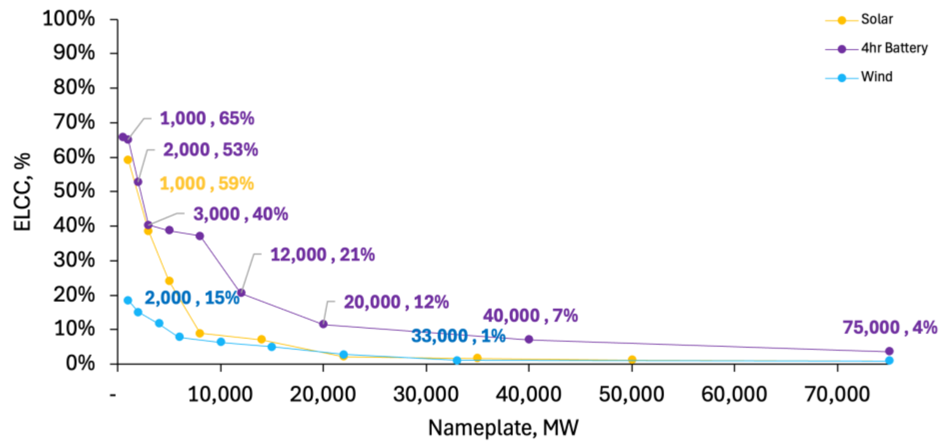
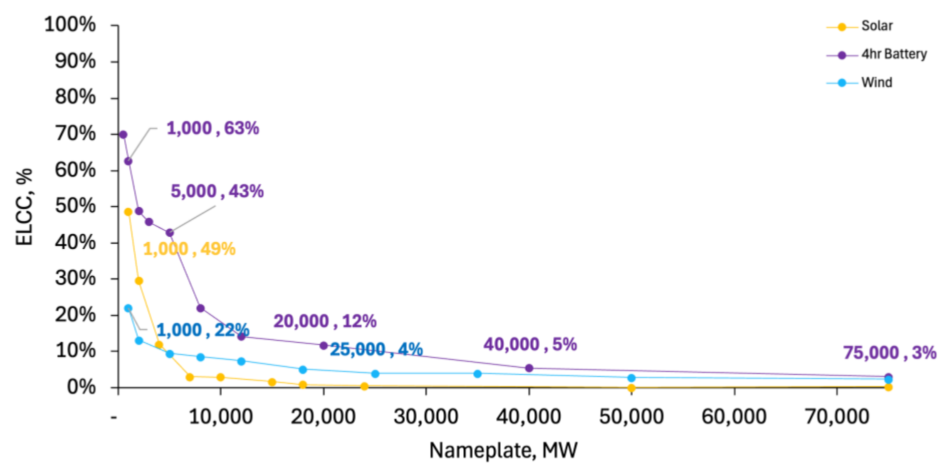


Figure 5-18: MISO LRZ 4 ELCC Curves



Generally, variable renewable energy and battery storage ELCCs exhibit diminishing returns as penetration increases. To illustrate this principle, consider the timing and duration of the system gross peak, before any renewables are brought online. In PJM and MISO today (late 2025), gross peaks typically occur in the middle of summer and are driven by cooling loads in the mid-afternoon. The first MWs of solar on the system receive a high marginal ELCC, since solar production in these hours is relatively high. However, as more solar resources are added to the system, the net peak load gradually shifts later into the afternoon, outside peak solar hours, which causes marginal ELCCs to decline with increasing penetration.

For wind resources, ELCCs are generally lower than solar because wind production is typically highest overnight and in the winter months, outside of the peak window. Wind ELCCs also decline with increasing penetration because of the same saturation effects as solar—as more wind is added, the net peak gradually shifts to hours where wind production is not as strong.

Battery storage is subject to similar dynamics. Battery ELCCs start high since system reliability events are relatively short in duration at first. However, as additional 4-hour batteries are added to meet these shorter-duration events, the net peak window adjusts and becomes longer in duration, leading to diminishing returns with the next tranche of storage.

5.3.7. Firm Capacity Imports to Illinois

The reliability requirements in each Illinois zone (MISO LRZ 4, ComEd zone) can be met by a combination of baseline (existing) and candidate (new) in-state capacity, as well as new out-of-state capacity contracted to provide reliability attributes to Illinois. The volume of out-of-state thermal capacity that can be selected to meet the in-state reliability constraint is informed by system topology and line limits. While the transmission representation in Figure 5-5 represents maximum line ratings, the import capability during the most challenging hours is generally much lower. The CETL and ZIA constraints from PJM and MISO respectively inform the firm import capability limits applied to new out-of-state thermal capacity towards meeting the in-state PRM requirement (Table 5-4). The CETL for the ComEd zone is assumed to be 5.7 GW in the first model year, expanding to 7.3 GW by 2035.[218] The ZIA for MISO LRZ 4 is assumed to be 7.7 GW in 2030, expanding to 11.5 GW and 11.7 GW by 2035 and 2040, respectively.[219] CETL and ZIA values increase over time in proportion to planned transmission expansions over time. The values in Table 5-4 below reflect maximum build limits on out-of-state gas that could provide firm capacity towards the in-state reliability target.

Table 5-4: Firm Import Limits for Illinois Capacity Zones (MW)

Zone	2030	2035	2040+
MISO LRZ 4 (ZIA)	7,757	11,505	11,723
ComEd zone (CETL)	5,700	7,283	7,283

[218] PJM, "2026/2027 RPM Base Residual Auction Planning Period Parameters." (May 9, 2025): https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2026-2027/2026-2027-planning-period-parameters-for-base-residual-auction-pdf.pdf.

[219] MISO, "2025-2026 PY Seasonal CIL/CEL Final Results." (October 24, 2024): https://cdn.misoenergy.org/20241024%20LOLEWG%20Item%2004%20PY%202025-2026%20Final%20CIL_CEL%20Results654989.pdf.

5.3.8. Renewable Portfolio Standard

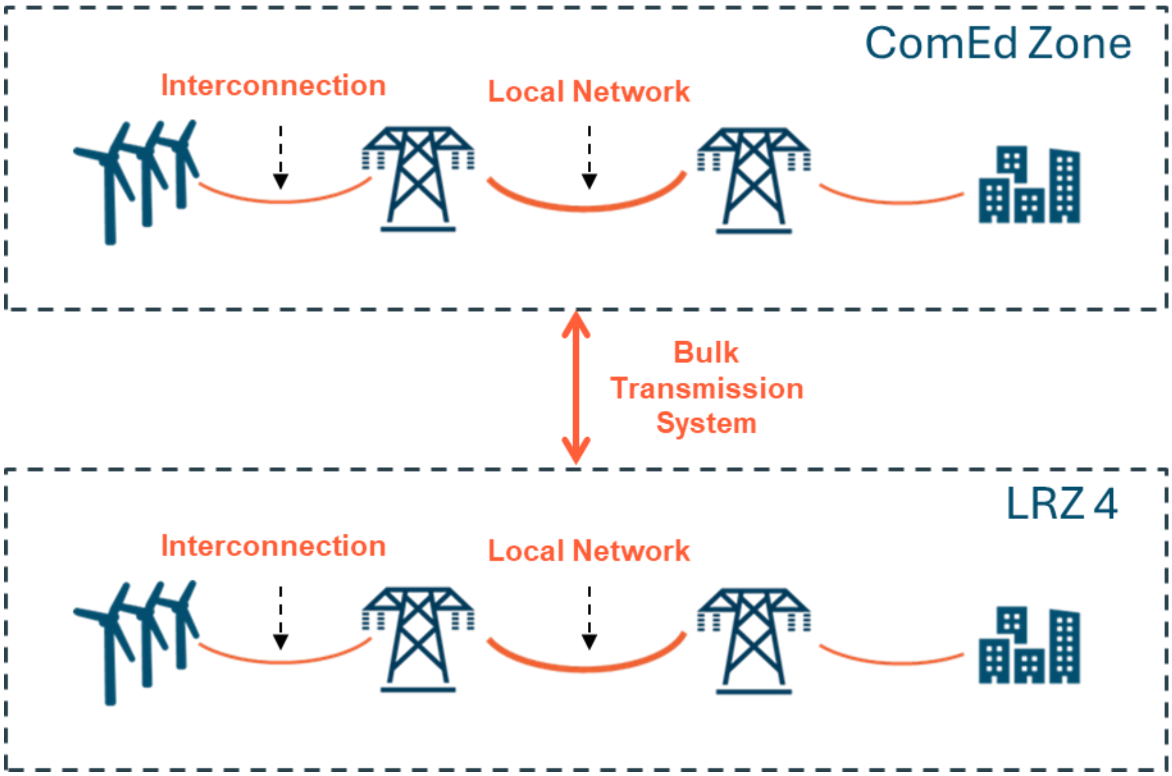
The RPS was modeled as six concurrent aggregate volumetric targets for MISO, PJM, and Illinois, including RTO-wide, regional, and resource-specific requirements. The RTO-wide targets for MISO and PJM (exclusive of Illinois) were calculated by applying each state's published RPS percentage to its forecasted load, adjusted for a 6.5% transmission and distribution (T&D) loss to convert to retail sales. Additional carve-outs are modeled for Dominion's RPS targets in PJM East, as well as the Illinois RPS target under the IPA Long-Term Plan, including technology-specific targets. Additional details on the translation of the REC procurement targets from the IPA Long-Term Plan into PLEXOS can be found in Appendix F.

5.3.9. Implementation of REAP Zones in PLEXOS

In PLEXOS, three types of transmission system components are considered in the capacity expansion model, as summarized below and in Figure 5-19:

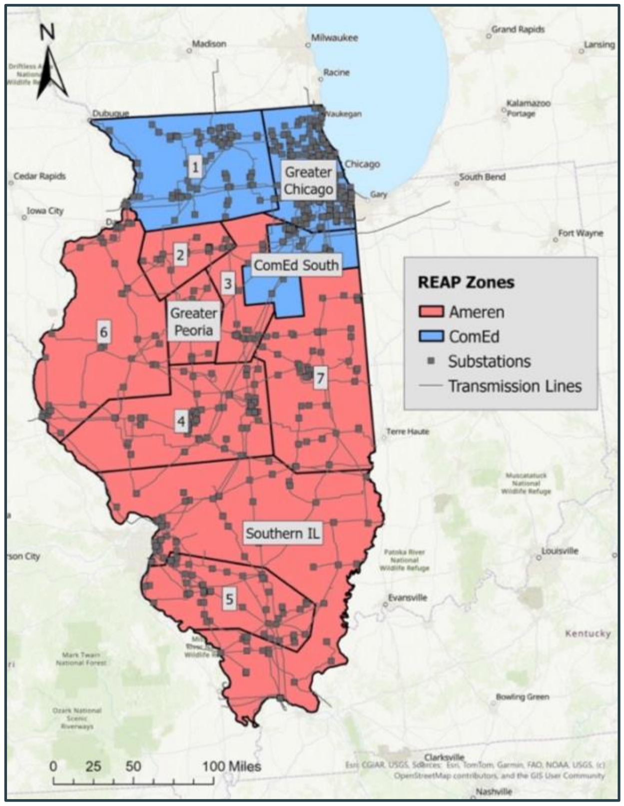
1. **Bulk transmission system**: Interzonal transfer capabilities, which are represented by the system topology and hourly flow limits between zones;
2. **Local network deliverability upgrades**: Transmission headroom within a zone that ensures that electricity can be delivered from where it is generated or discharged to load centers;
3. **Interconnection:** Spur lines and/or other local upgrades at the point of interconnection to connect generators to the transmission system.

Figure 5-19: Illustration of Transmission Components



The REAP zones, as discussed in the Illinois 2025 Draft REAP, are used to define deliverability sub-areas within the MISO LRZ 4 and ComEd PLEXOS zones. These represent local network deliverability constraints and upgrade costs. The model tracks available headroom and may select transmission upgrades, at a cost, to unlock additional headroom to integrate additional resources. More detail on these dynamics and assumptions are included in the Appendix F. A map of the REAP zones is provided in Figure 5-20 below.

Figure 5-20: REAP Zones in Illinois



5.4. Long Term Resource Adequacy Results

The following sections summarize the outcomes of the resource adequacy and long-term capacity expansion modeling conducted for this study. The analysis begins with the Base Case, which reflects current Illinois and RTO-wide policy, load forecasts, and resource cost assumptions, including fossil retirements assumed to comply with the CEJA policy, and the continued availability of new gas development. This scenario establishes a benchmark portfolio that meets Illinois and RTO-wide reliability, energy, and policy needs through 2045, and serves as a reference point for understanding the impacts of alternative assumptions and policies tested in other cases, as discussed in section 5.1.2.

Across all cases, the modeling framework is designed to identify cost-optimal resource portfolios that ensure resource adequacy. These calculated portfolios illustrate how the future may unfold as opposed to distinctive plans. Each scenario showcases how different drivers—including the pace of retirements, technology availability, and policy constraints—alter the types and timing of resources selected to meet Illinois and system-wide projected needs.

5.4.1. Base Case Results

In the Base case, the model finds that both PJM and MISO systems must make significant investments in new capacity to offset planned retirements and meet growing demand. These investments span battery storage, firm capacity (primarily gas), and renewable generation, with selections shaped by a combination of capacity needs, cost dynamics, and policy requirements.

Figure 5-21 and Figure 5-22 represent the cumulative nameplate capacity additions in PJM and MISO LRZs 1-7, respectively, inclusive of Illinois selected capacity. In both markets, battery storage plays a critical near-term role: nearly 20 GW of batteries are selected in PJM and a comparable volume in MISO LRZs 1-7 by 2030, reflecting their relative cost-effectiveness of equivalent accredited capacity compared to new gas. These batteries address near-term resource adequacy needs in an environment where new gas faces cost or permitting barriers. After 2030, when the cost for new gas capacity is assumed to return to pre-scarcity levels, new CCGTs emerge as the primary form of accredited capacity selected in both RTOs. These additions help meet rising load and replace retiring thermal units. Solar and wind are selected to support RPS targets, particularly in regions with favorable resource quality and policy mandates, most notably in the eastern PJM, the ComEd zone, and MISO LRZs 1, 4, and 7.

Figure 5-21: PJM Selected Nameplate Capacity (GW) | Base Case

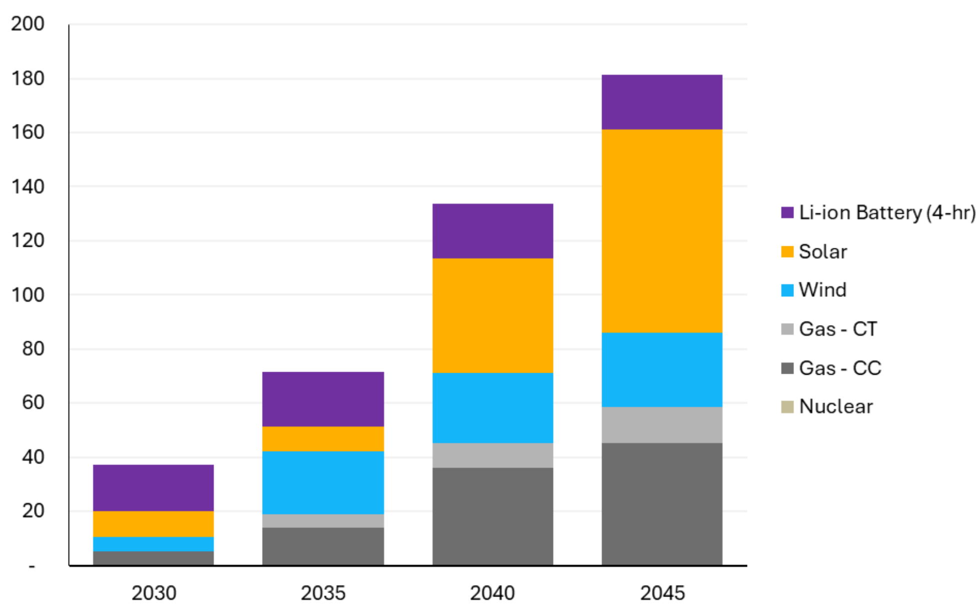


Table 5-5: PJM Selected Nameplate Capacity (GW) | Base Case

Technology	2030	2035	2040	2045
Nuclear	0	0	0	0
Gas - CC	5	14	36	45
Gas - CT	0	5	9	13
Wind	5	23	26	27
Solar	9	9	42	75
Li-ion Battery (4-hr)	17	20	20	20

Figure 5-22: MISO LRZs 1-7 Selected Nameplate Capacity (GW) | Base Case

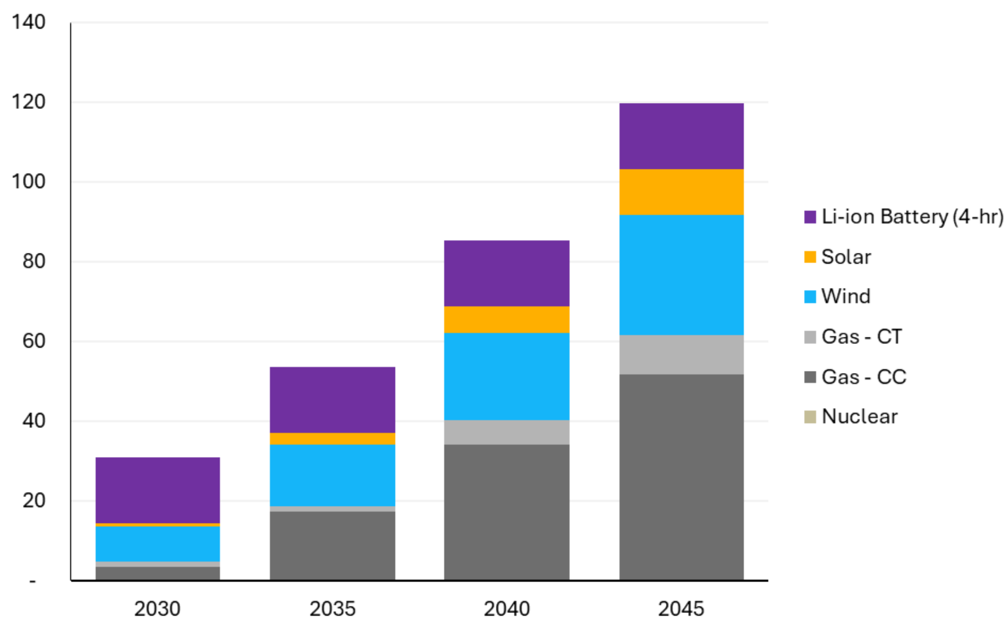


Table 5-6: MISO LRZs 1-7 Selected Nameplate Capacity (GW) | Base Case

Technology	2030	2035	2040	2045
Nuclear	-	-	-	-
Gas - CC	3	17	34	52
Gas - CT	1	2	6	10
Wind	9	15	22	30
Solar	1	3	7	12
Li-ion Battery (4-hr)	17	17	17	17

Figure 5-23 and Figure 5-24 below summarize the accredited capacity balance by technology in PJM and MISO LRZs 1-7, respectively, also inclusive of Illinois capacity. These results illustrate the growing accredited capacity need between 2030 and 2045. Across both market, thermal generators play a critical role in ensuring the resource adequacy target is satisfied. In PJM, roughly 25 GW of accredited capacity additions are needed over the modeling horizon just to meet growing demand, while additional accredited capacity is needed to replace the planned retirements of large coal and gas generators. When accounting for accredited capacity, the 17 GW of battery additions in nameplate terms translates to roughly 14 GW of accredited capacity in 2030. However, starting in 2035, CCGTs emerge as the predominant new accredited capacity resource added to the system. MISO LRZs 1-7 have higher penetrations of renewable energy and battery storage compared to PJM, and by the 2040s some additional CT peaking capacity is added as a cheaper alternative to CCGTs.

Figure 5-23: PJM Total Accredited Capacity (GW) | Base Case

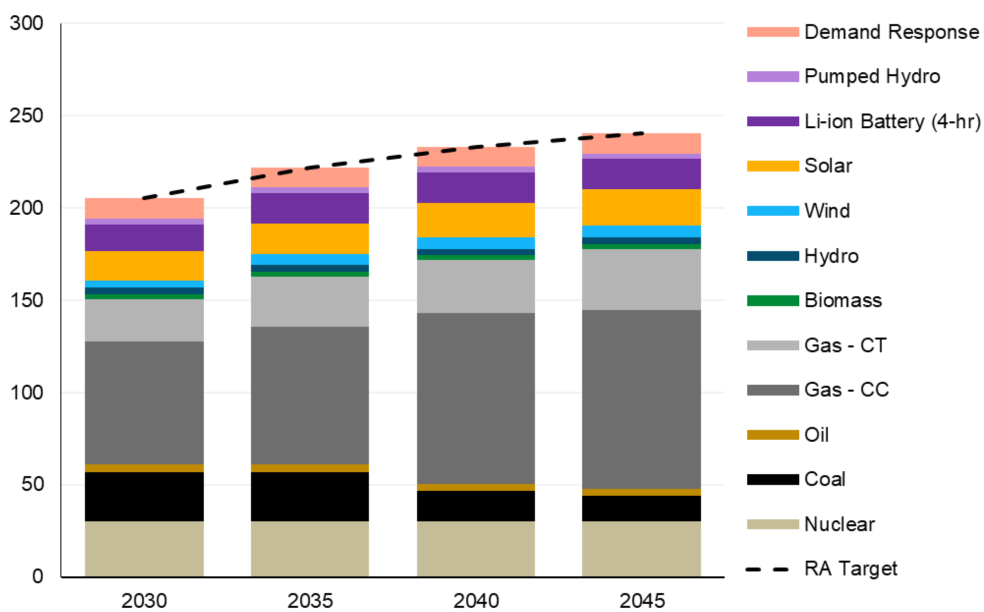


Table 5-7: PJM Total Accredited Capacity (GW) | Base Case

Technology	2030	2035	2040	2045
Nuclear	30	30	30	30
Coal	26	26	16	14
Oil	4	4	4	4
Gas - CC	67	75	92	97
Gas - CT	23	27	29	33
Biomass	3	3	3	3
Hydro	3	3	3	3
Wind	4	6	6	6
Solar	16	16	19	20
Li-ion Battery (4-hr)	14	16	16	16
Pumped Hydro	3	3	3	3
Demand Response	11	11	11	11

Figure 5-24: MISO LRZs 1-7 Total Accredited Capacity (GW) | Base Case

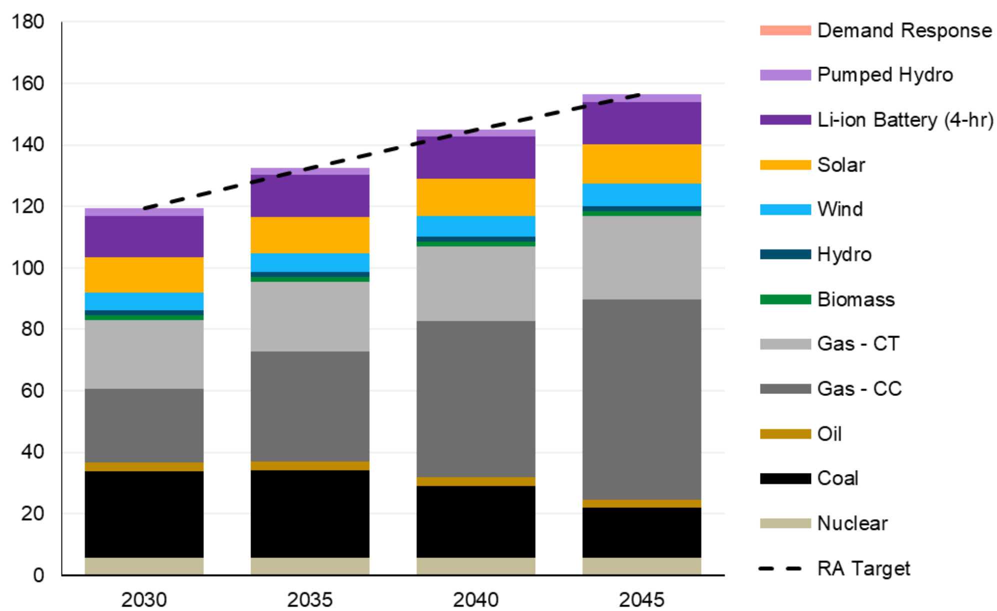


Table 5-8: MISO LRZs 1-7 Total Accredited Capacity (GW) | Base Case

Technology	2030	2035	2040	2045
Nuclear	6	6	6	6
Coal	28	28	23	16
Oil	3	3	3	3
Gas - CC	24	36	51	65
Gas - CT	22	23	24	27
Biomass	2	2	2	1
Hydro	2	2	2	2
Wind	6	6	7	7
Solar	11	12	12	13
Li-ion Battery (4-hr)	14	14	14	14
Pumped Hydro	2	2	2	2
Demand Response	0	0	0	0

Figure 5-25 through Figure 5-28 below summarize the selected capacity additions and accredited capacity contributions by technology in MISO LRZ 4 and the ComEd zone for the Base case. These results underscore the stark differences between MISO LRZ 4, a renewables-rich supply zone with ample interregional transmission access and moderate load growth, and the ComEd zone, a supply- and transmission-constrained region that utilizes larger volumes of accredited capacity to meet growing load and replace retiring fossil generators. Most of the highest-capacity factor wind and solar generation is available in the MISO portion of Illinois, and consequently most renewable energy resources selected in Illinois are concentrated here. While LRZ 4 does experience load growth and fossil generator retirements throughout the modeling horizon that require capacity additions, it is able to predominately meet its reliability targets by importing firm capacity from neighboring regions without exceeding its ZIA. The model selects roughly 1 GW of Li-ion batteries for LRZ 4 in 2030, when batteries are cheaper than out-of-state gas on an equivalent accredited capacity basis. As shown in Figure 5-27, as fossil generators are retired in LRZ 4 and replaced with firm capacity imports, the in-state accredited capacity total shrinks by 2045 to nearly half of its 2030 value.

In the ComEd zone, by contrast, higher load growth, fossil generator retirements, more limited renewable potential, and transmission import limits drive the model to select more in-state accredited capacity. In 2030, the model selects 2 GW of new batteries and also requires full utilization of the CETL, identifying out-of-state gas as more economical than in-state gas due to assumed cheaper site control and labor costs in neighboring states, as well as a hydrogen-readiness requirement for any in-state generation. In later years, new, zero-carbon-fuel capable in-state gas CT units are selected to replace retiring fossil generators and maintain local reliability and wind additions increase modestly in later years to complement this accredited capacity. While these new turbines are able to utilize zero-carbon fuels prior to the 2045 CEJA deadline, it is not a requirement—they are modeled in accordance with the CEJA policy. By 2045, the accredited capacity previously provided by fossil generators is entirely replaced by new in-state CTs, capable of operating on zero carbon fuels, and firm capacity imports from out-of-state gas, as summarized in Figure 5-27.

Between the ComEd zone and MISO LRZ 4, the Base case replaces existing in-state fossil fuel generation with over 13 GW of new in-state peaking capacity and 18 GW of new out-of-state gas generation to meet local reliability requirements and adds roughly 11 GW of solar and 13 GW of wind to meet the 50% RPS target by 2045.

Figure 5-25: MISO LRZ 4 Selected Capacity (GW) | Base Case

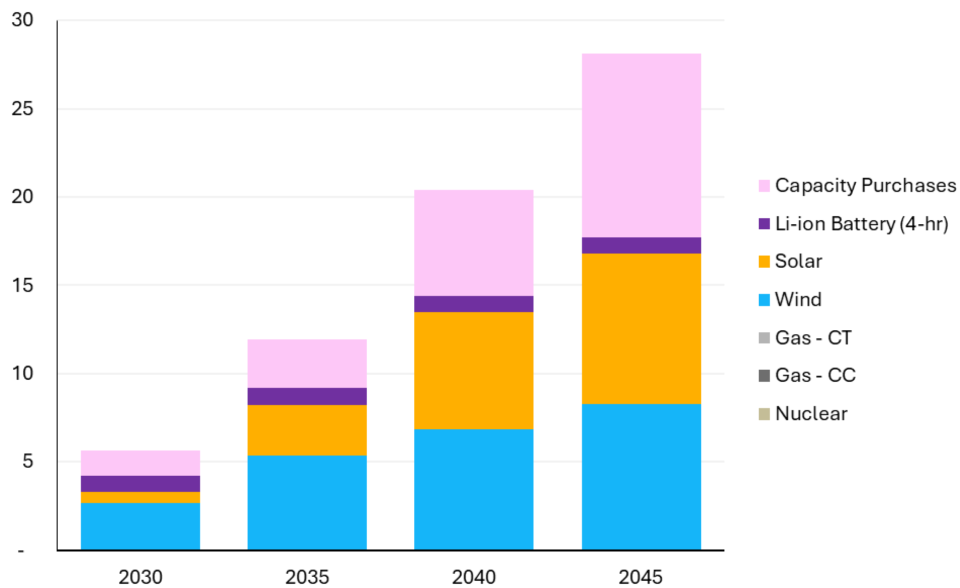


Table 5-9: MISO LRZ 4 Selected Capacity (GW) | Base Case

Technology	2030	2035	2040	2045
Nuclear	-	-	-	-
Gas - CC	-	-	-	-
Gas - CT	-	-	-	-
Wind	3	5	7	8
Solar	1	3	7	8
Li-ion Battery (4-hr)	1	1	1	1
Capacity Purchases	1	3	6	10

Figure 5-26: ComEd Zone Selected Capacity (GW) | Base Case

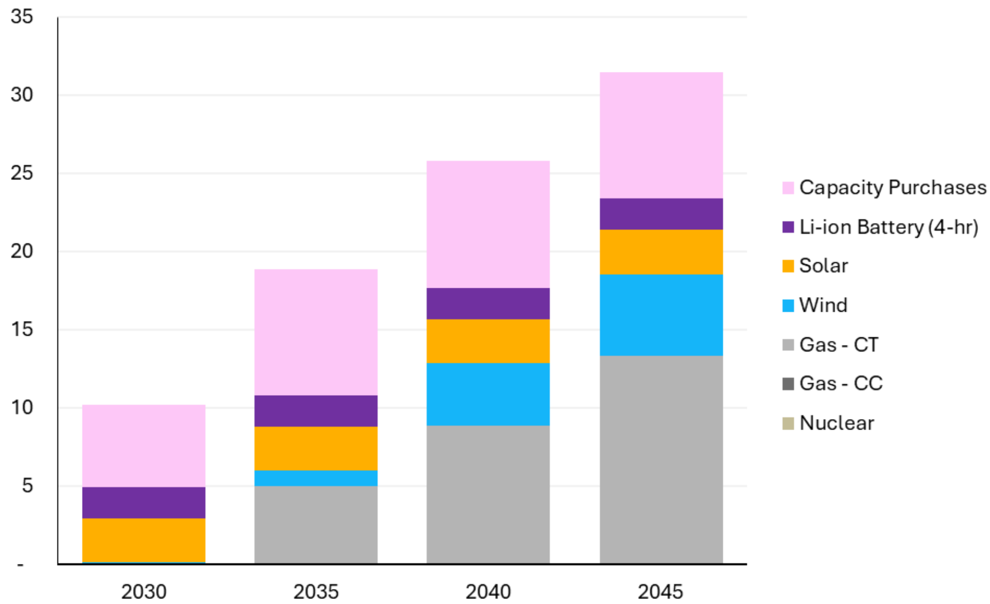


Table 5-10: ComEd Zone Selected Capacity (GW) | Base Case

Technology	2030	2035	2040	2045
Nuclear	-	-	-	-
Gas - CC	-	-	-	-
Gas - CT	0	5	9	13
Wind	0	1	4	5
Solar	3	3	3	3
Li-ion Battery (4-hr)	2	2	2	2
Capacity Purchases	5	8	8	8

Figure 5-27: MISO LRZ 4 Total Accredited Capacity (GW) | Base Case

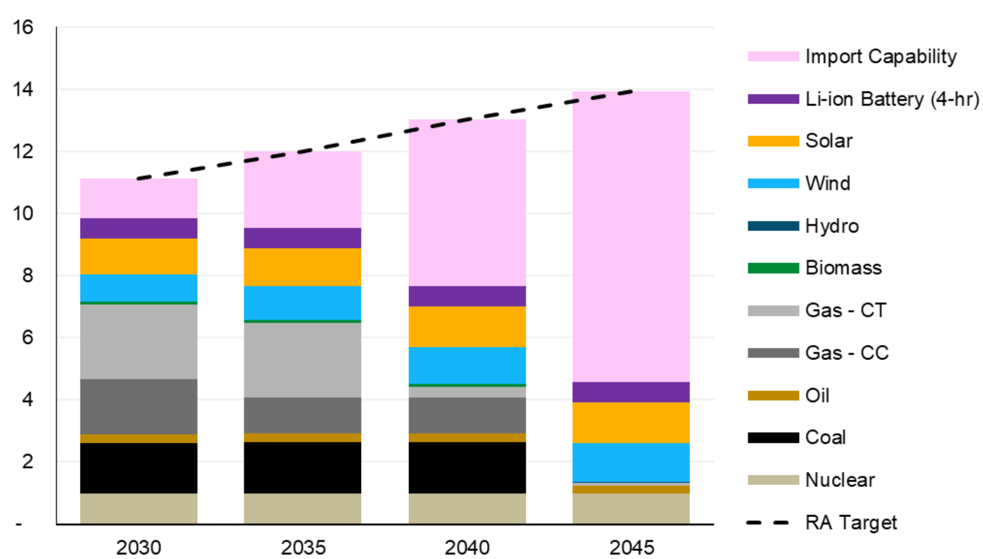


Table 5-11: MISO LRZ 4 Total Accredited Capacity (GW) | Base Case

Technology	2030	2035	2040	2045
Nuclear	1	1	1	1
Coal	2	2	2	-
Oil	0	0	0	0
Gas - CC	2	1	1	-
Gas - CT	2	2	0	0
Biomass	0	0	0	0
Hydro	0	0	0	0
Wind	1	1	1	1
Solar	1	1	1	1
Li-ion Battery (4-hr)	1	1	1	1
Import Capability	1	2	5	9
RA Target	11	12	13	14

Figure 5-28: ComEd Zone Total Accredited Capacity (GW) | Base Case

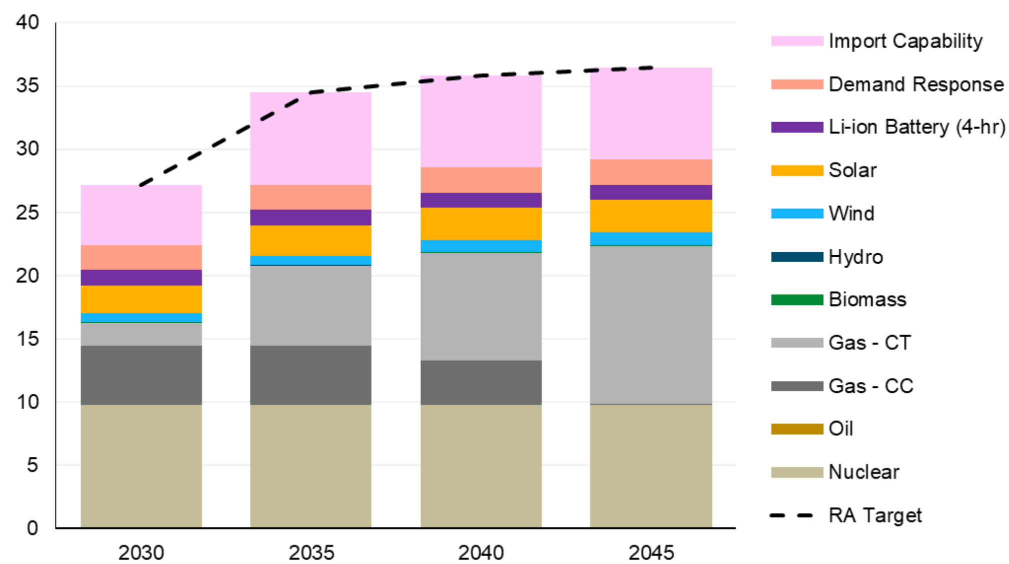


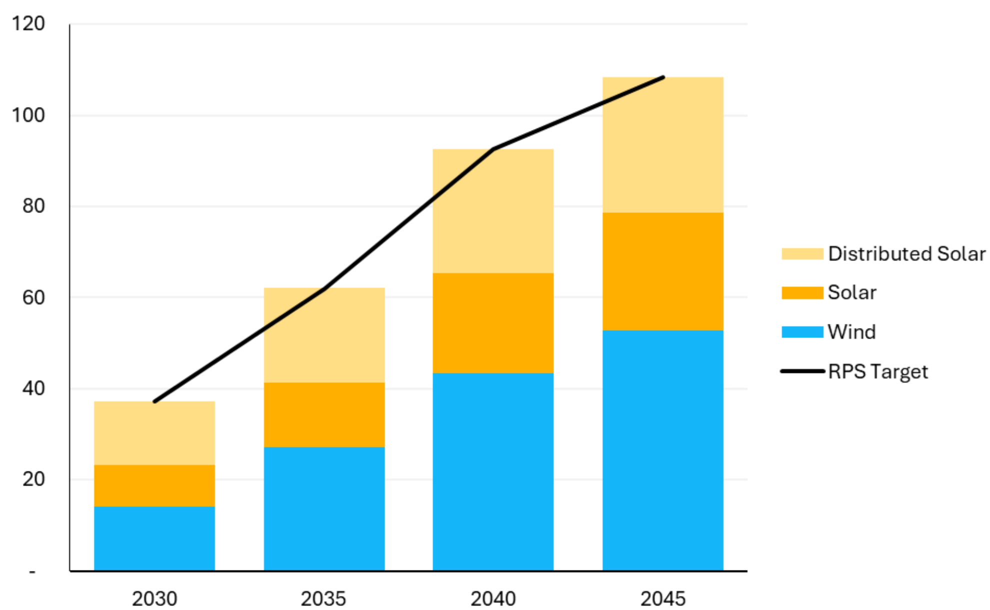
Table 5-12: ComEd Zone Total Accredited Capacity (GW) | Base Case

Technology	2030	2035	2040	2045
Nuclear	10	10	10	10
Oil	0	0	0	0
Gas - CC	5	5	4	0
Gas - CT	2	6	8	13
Biomass	0	0	0	0

Hydro	0	0	0	0
Wind	1	1	1	1
Solar	2	2	3	3
Li-ion Battery (4-hr)	1	1	1	1
Demand Response	2	2	2	2
Import Capability	5	7	7	7
RA Target	27	34	36	36

Renewable resources are selected by the model in Illinois to meet the 50% RPS target detailed in the latest IPA Long-Term Plan[220]. This includes in-state utility-scale solar, wind, and distributed solar. Total REC procurement targets, as well as carve-outs by technology and segment, are taken directly from the IPA Long-Term Plan and are not the results of PLEXOS portfolio optimization. In order to achieve the 50% RPS by 2045, Illinois is projected to need roughly 53 TWh of wind RECs, 26 TWh of utility-scale solar RECs, and 30 TWh of distributed solar RECs (aggregated across multiple customer programs and sectors). Based on the available land area, relative resource quality, and available transmission headroom, the majority of new RECs in Illinois are generated from resources in MISO LRZ 4.

Figure 5-29: Illinois Renewable Generation (TWh)



[220] IPA Long-Term Renewable Resources Procurement Plan (October 20, 2025): https://ipa.illinois.gov/renewable-resources/long-term-plan.html.

Table 5-13: Illinois Renewable Generation (TWh)

Technology	2030	2035	2040	2045
Wind	14	27	43	53
Solar	9	14	22	26
Distributed Solar	14	21	27	30

Figure 5-30 and Figure 5-31 summarize the annual generation mix in MISO LRZ 4 and the ComEd zone, respectively. In MISO LRZ 4, larger capacities of wind and solar are more than sufficient to replace planned thermal generation retirements and result in this region becoming a net exporter of electricity by the mid-2030s. Meanwhile, in the ComEd zone, larger retirements of baseload generation and scant renewable resource supply cause this zone to experience a growing dependence on energy imports into the 2030s and 2040s. While Illinois achieves near-zero in-state emissions by 2045, fossil generator retirements cause Illinois to become a net importer of electricity starting in 2035, and the emissions burden has largely shifted from in-state to out-of-state generation. On a net basis, Illinois is projected to import roughly 7 TWh per year in 2045, when adding together the net imports of MISO LRZ 4 (-30) and the ComEd zone (37), roughly 3% of the State's total annual load.

Figure 5-30: MISO LRZ 4 Annual Generation (TWh)

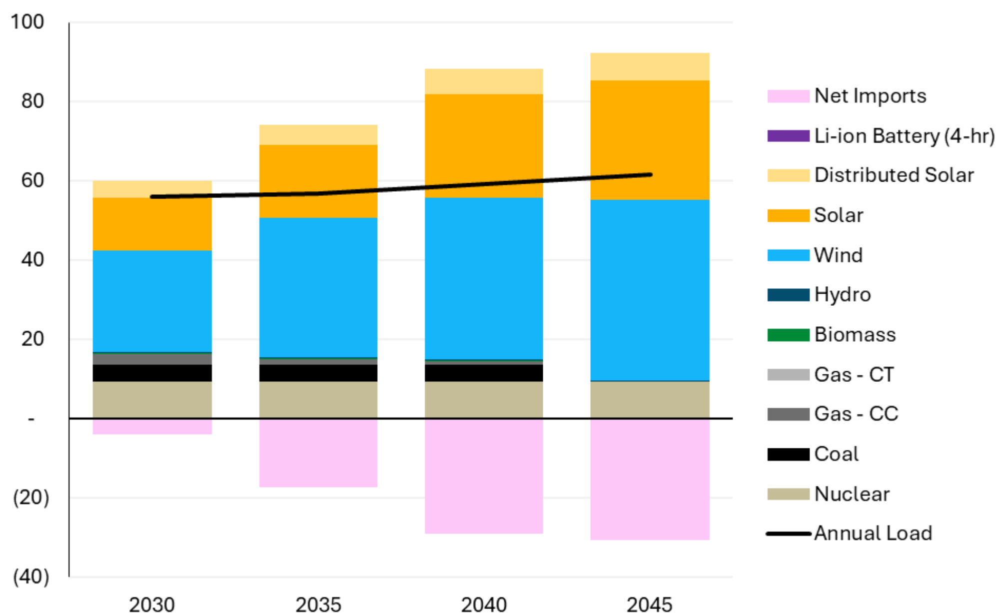


Table 5-14: MISO LRZ 4 Annual Generation (TWh)

Technology	2030	2035	2040	2045
Nuclear	9	9	9	9
Coal	4	4	4	-
Gas - CC	3	1	1	-
Gas - CT	-	-	-	-
Biomass	0	0	0	0
Hydro	0	0	0	0
Wind	26	35	41	46
Solar	14	18	26	30
Distributed Solar	4	5	6	7
Li-ion Battery (4-hr)	(0)	(0)	(0)	(0)
Net Imports	(4)	(17)	(29)	(30)

Figure 5-31: ComEd Zone Annual Generation (TWh)

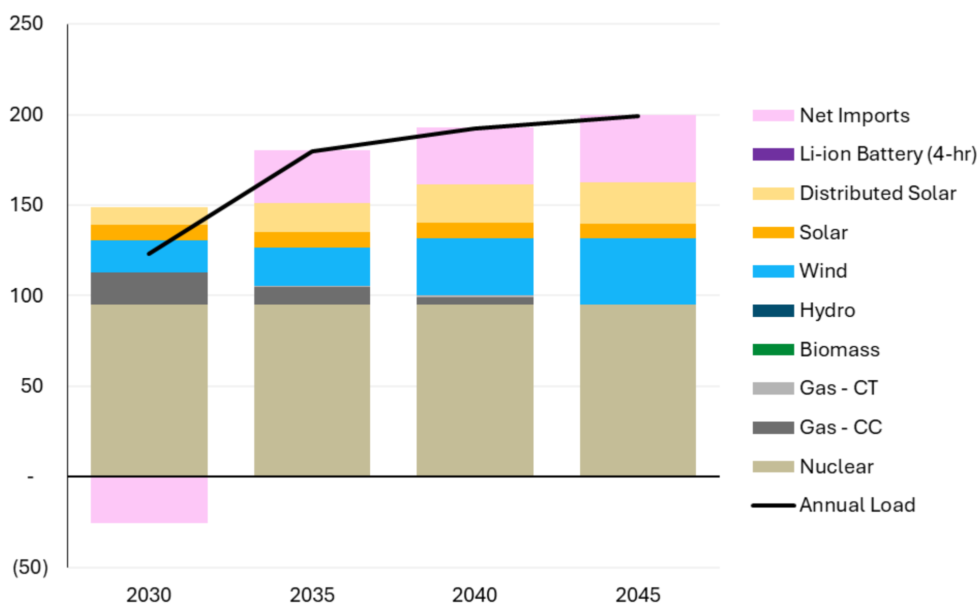


Table 5-15: ComEd Zone Annual Generation (TWh)

Technology	2030	2035	2040	2045
Nuclear	95	95	95	95
Gas - CC	18	10	4	-
Gas - CT	-	1	1	-
Biomass	0	0	0	0
Hydro	0	0	0	0
Wind	18	21	32	36
Solar	8	8	8	8
Distributed Solar	10	16	21	23
Li-ion Battery (4-hr)	(0)	(0)	(0)	(0)
Net Imports	(26)	29	31	37

5.4.2. CEJA Extension Case Results

The CEJA Extension case presents an alternative policy future where retirement deadlines under CEJA are extended due to projected capacity shortfalls. Under this scenario, no fossil generator retirements by plants subject to CEJA restrictions are assumed to occur before 2045, and the planned retirements of other coal units before 2030 are delayed until 2035. All other inputs and assumptions are identical to the Base case, including the application of generator emissions reductions requirements, reflected in the model as a capacity factor limit over time. Figure 5-32 below summarizes the differences in thermal retirements between the two cases.

Figure 5-32: Illinois Cumulative Retired Capacity by Year (GW)

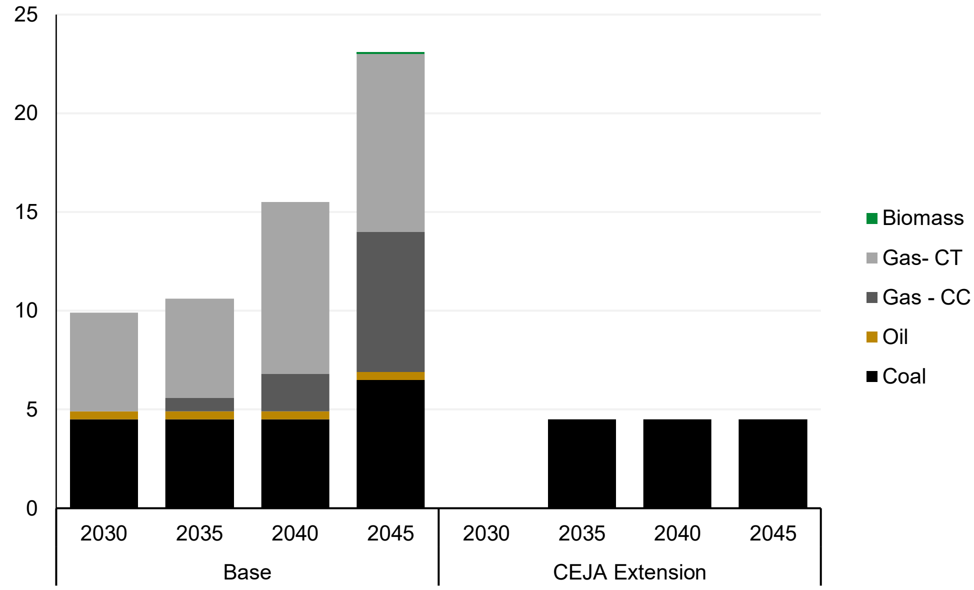


Table 5-16: Illinois Cumulative Retired Capacity by Year (GW)

Technology	Base				CEJA Extension			
	2030	2035	2040	2045	2030	2035	2040	2045
Coal	5	5	5	7	-	5	5	5
Oil	0	0	0	0	-	-	-	-
Gas - CC	-	1	2	7	-	-	-	-
Gas- CT	5	5	9	9	-	-	-	-
Biomass	-	-	-	0	-	-	-	-

Figure 5-33 and Figure 5-34 below compare the model-selected capacities in MISO LRZ 4 and the ComEd zone between the Base case and the CEJA Extension case. As expected, delaying fossil generator retirements reduces the accredited capacity need in both zones. In MISO LRZ 4, the net impact of delaying CEJA is most noticeable in the reduced dependence on firm capacity imports, which were the cheapest capacity option selected in the Base case to replace in-state thermal generation to meet the PRM. In the ComEd zone, where the capacity shortfall is still large due to projected load growth, delaying CEJA directly reduces the volume of new in-state gas needed for reliability. Finally, due to reduced transmission utilization in the ComEd zone, the system is also able to shift several hundred MW of solar and wind capacity from MISO LRZ 4 into the ComEd zone to reduce import need.

Figure 5-33: MISO LRZ 4 Selected Capacity (GW)

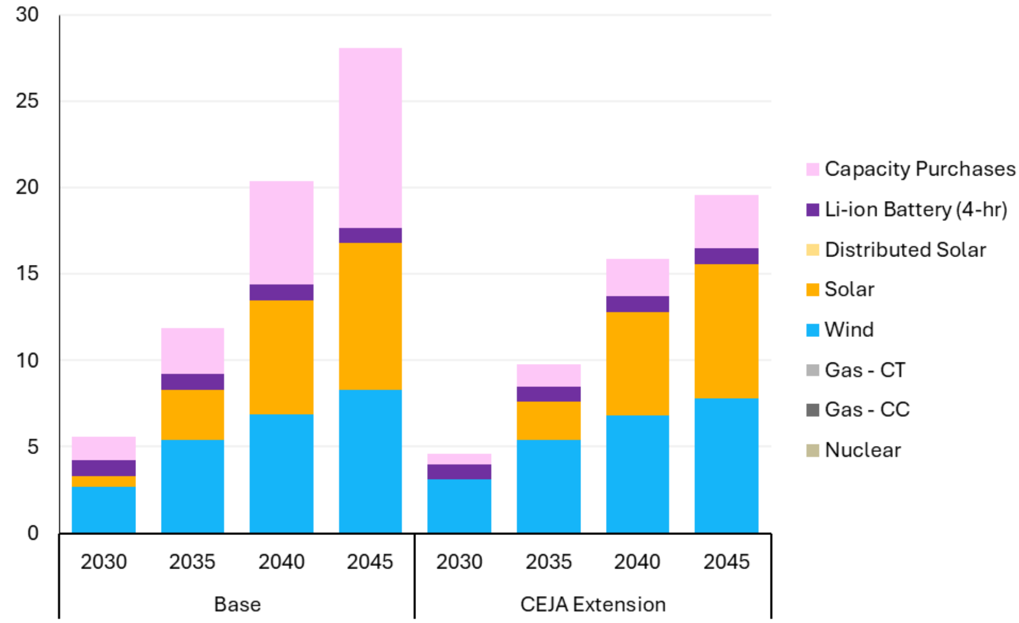


Table 5-17: MISO LRZ 4 Selected Capacity (GW)

Technology	Base				CEJA Extension			
	2030	2035	2040	2045	2030	2035	2040	2045
Wind	3	5	7	8	3	5	7	8
Solar	1	3	7	9	-	2	6	8
Li-ion Battery (4-hr)	1	1	1	1	1	1	1	1
Capacity Purchases	1	3	6	10	1	1	2	3

Figure 5-34: ComEd Zone Selected Capacity (GW)

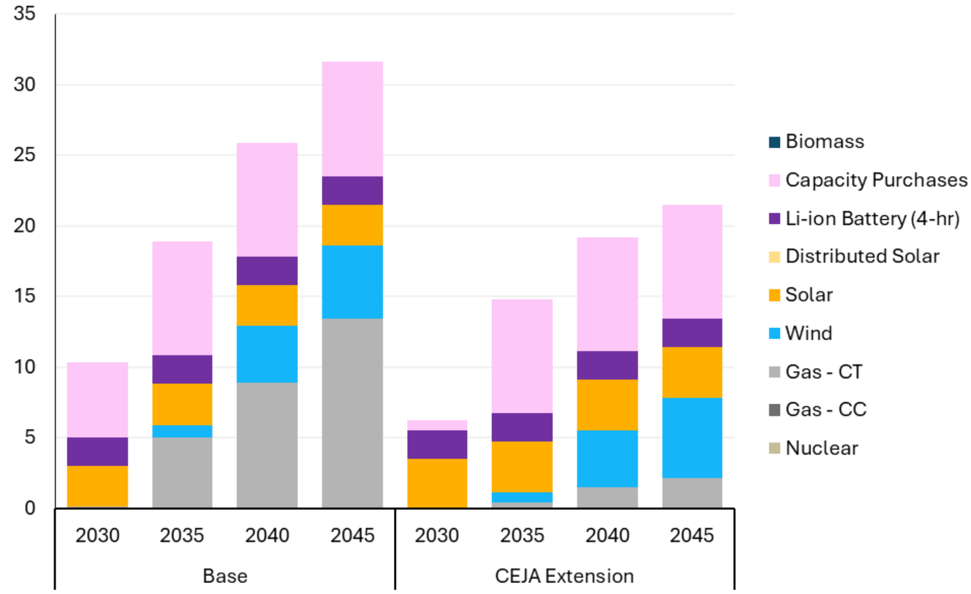


Table 5-18: ComEd Zone Selected Capacity (GW)

Technology	Base				CEJA Extension			
	2030	**2035**	**2040**	**2045**	**2030**	**2035**	**2040**	**2045**
Gas - CT	0	5	9	13	-	0	2	2
Wind	0	1	4	5	-	1	4	6
Solar	3	3	3	3	4	4	4	4
Li-ion Battery (4-hr)	2	2	2	2	2	2	2	2
Capacity Purchases	5	8	8	8	1	8	8	8

Figure 5-35: MISO LRZ 4 Annual Generation (TWh) | Base Case

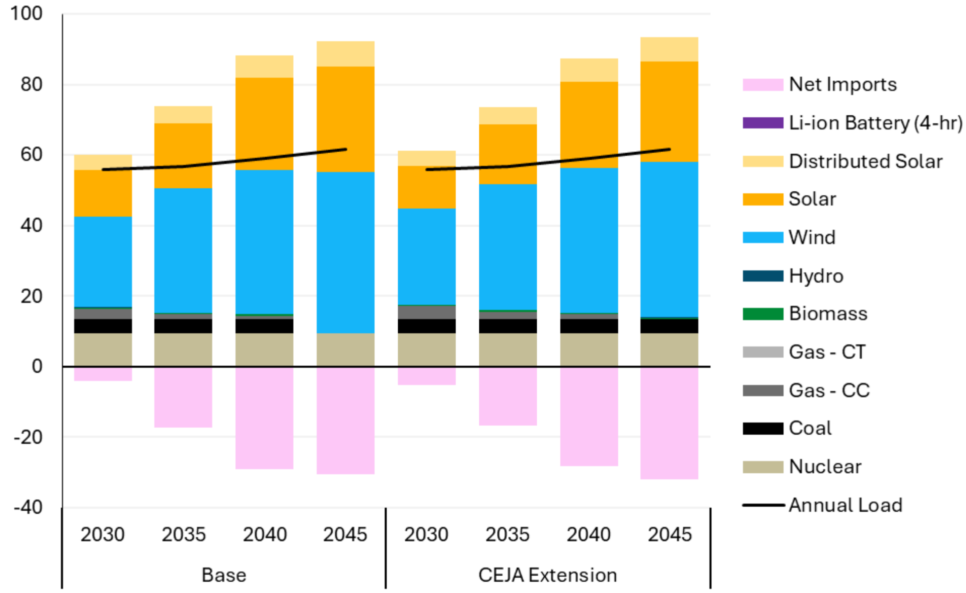


Table 5-19: MISO LRZ 4 Annual Generation (TWh) | Base Case

Technology	Base				CEJA Extension				
	2030	2035	2040	2045	2030		2035	2040	2045
Nuclear	9	9	9	9	9		9	9	9
Coal	4	4	4	-	4		4	4	4
Gas - CC	3	1	1	-	4		2	1	0
Gas - CT	-	-	-	-	-		-	0	-
Biomass	0	0	0	0	0		0	0	0
Hydro	0	0	0	0	0		0	0	0
Wind	26	35	41	46	27		36	41	44
Solar	14	18	26	30	12		17	25	29
Distributed Solar	4	5	6	7	4		5	6	7
Li-ion Battery (4-hr)	(0)	(0)	(0)	(0)	(0)		(0)	(0)	(0)
Net Imports	(4)	(17)	(29)	(30)	(5)		(17)	(28)	(32)
Annual Load	56	57	59	62	56	57	59		62

Figure 5-36: ComEd Zone Annual Generation (TWh) | Base Case

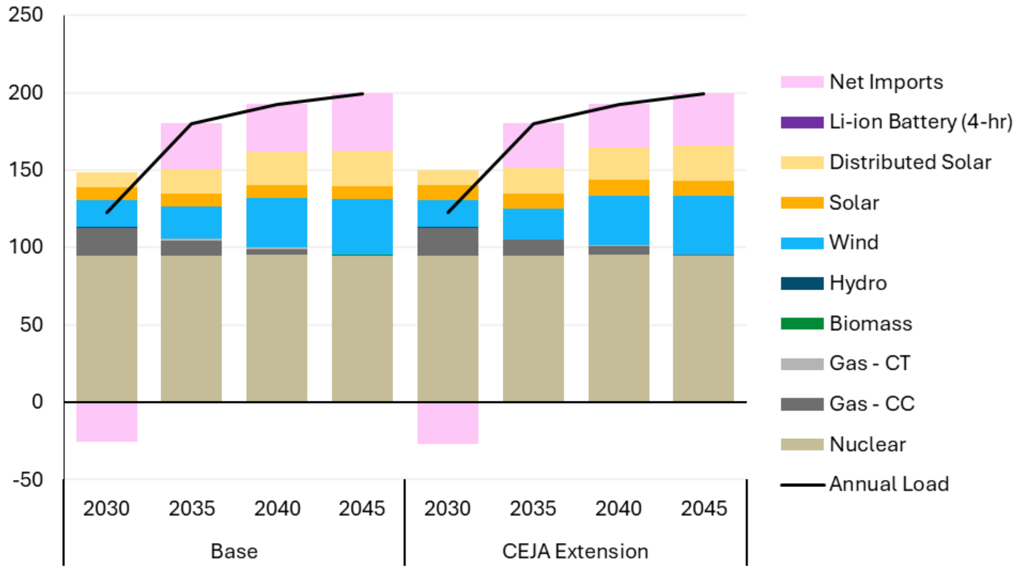


Table 5-20: ComEd Zone Annual Generation (TWh) | Base Case

Technology	Base				CEJA Extension			
	2030	**2035**	**2040**	**2045**	**2030**	**2035**	**2040**	**2045**
Nuclear	95	95	95	95	95	95	95	95
Gas - CC	18	10	4	0	18	10	6	0
Gas - CT	-	1	1	0	-	0	0	0
Biomass	0	0	0	0	0	0	0	0
Hydro	0	0	0	0	0	0	0	0
Wind	18	21	32	36	18	20	32	38
Solar	8	8	8	8	10	10	10	10
Distributed Solar	10	16	21	23	10	16	21	23
Li-ion Battery (4-hr)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Net Imports	(26)	29	31	37	(27)	29	28	34
Annual Load	123	180	192	199	123	180	192	199

5.4.3. Future Generation Dynamics from Fossil Generators in Illinois

In a future where new reliability resources are needed to meet load growth in PJM, MISO, and Illinois, extending the operations of existing Illinois power plants under CEJA avoids the need for (and cost of) building new resources to replace this retiring accredited capacity. In the PLEXOS modeling, the annual energy mix of Illinois zones does not change very much whether in-state fossil generators are retired or extended—indicating that these units do not run very often within the PLEXOS capacity expansion simulation (which uses a selection of sampled days and hours in each model year to inform the resource selection).

To more thoroughly understand the nature of the reliability role that fossil generators may play in Illinois as resource adequacy needs evolve, E3 analyzed the generation profiles of the Illinois existing fossil generator fleet across hundreds of reliability conditions using the RECAP model set up for this study. E3 simulated dispatch of all generators in the ComEd and LRZ 4 zones with a Monte Carlo sampling of 340 weather years and comparing the expected unserved energy (EUE in GWh) between two cases: the CEJA Extension case above and an alternate case in which the in-state fossil generators are retired but the capacity is not replaced with new resources. The change in EUE between cases across each simulated weather year serves as a measure of the energy output expected from fossil generators to support system reliability under a wide range of conditions.

In ComEd and LRZ 4 zones, existing fossil generators are needed only in a narrow slice of hours across the 340 weather-year Monte Carlo draws. In the ComEd zone, fossil generators are needed in approximately 388 hours total, or less than 0.1% of all simulated hours, resulting in a capacity factor of less than 1% in aggregate.

Figure 5-37 and Figure 5-38 present the frequency (in hours) of the difference in expected unserved energy levels (in MW) between the two cases in the ComEd zone (with and without fossil generators online) and LRZ 4 zones respectively. This distribution represents the reliability benefit of the fossil generators across all simulated weather years.

Figure 5-37: ComEd Zone Fossil Generators Contribution in Needed Hours

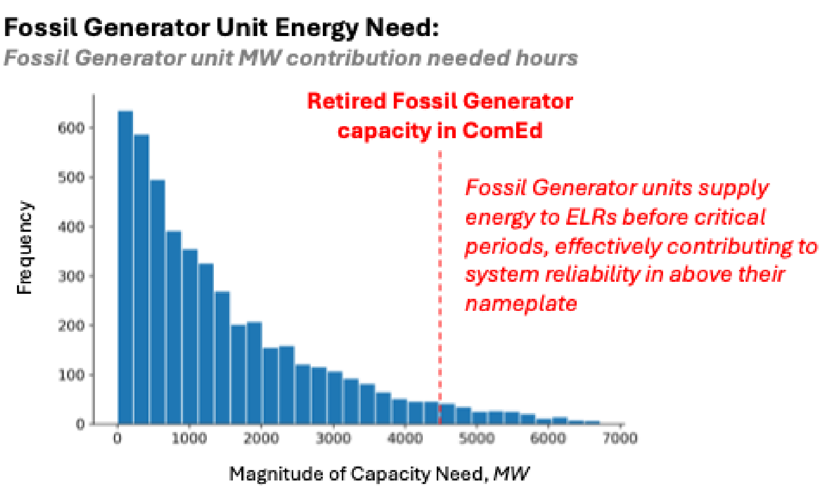
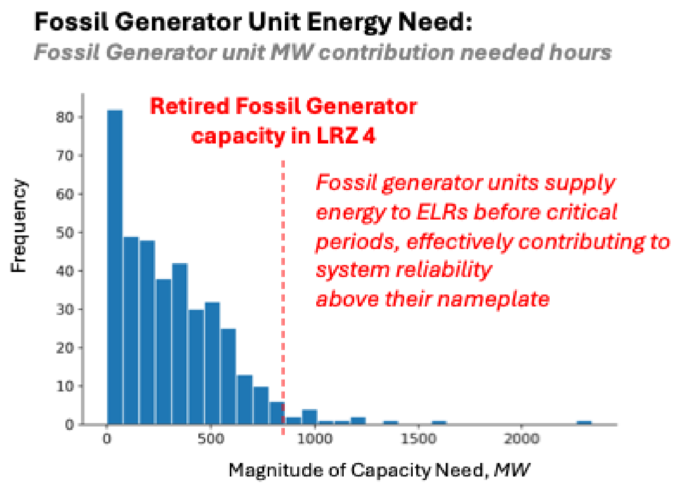


Figure 5-38: LRZ 4 Fossil Generators Contribution in Needed Hours



The RECAP simulations yielded 340 different weather year results in each case—by ordering cases from the highest to lowest levels of expected unserved energy, we can assess whether the reliability benefit of these units changes from a 'median' year (50th percentile of EUE) to a 'challenging year' (90th percentile of EUE).[221]

In the ComEd zone and LRZ 4, existing fossil generators provide the most reliability value in evening hours of July, as depicted in Figure 5-39 and Figure 5-40**,** both in the 'challenging' and median simulation years; however, the magnitude decreases sharply in the latter. This analysis was performed using the projected load and generation mix in 2030 in both zones. Additional analysis would be required to evaluate utilization of these generators in alternative future system conditions.

[221] A challenging weather year is a Monte Carlo simulation year characterized by a combination of extreme system load, low renewable generation, and meteorological conditions that create sustained stress on the power system. These conditions often lead to concentrated loss-of-load events, making the year one of the most difficult for maintaining resource adequacy.

Figure 5-39: ComEd Zone Expected Unserved Energy Without Fossil Generators (If Capacity is Not Replaced)

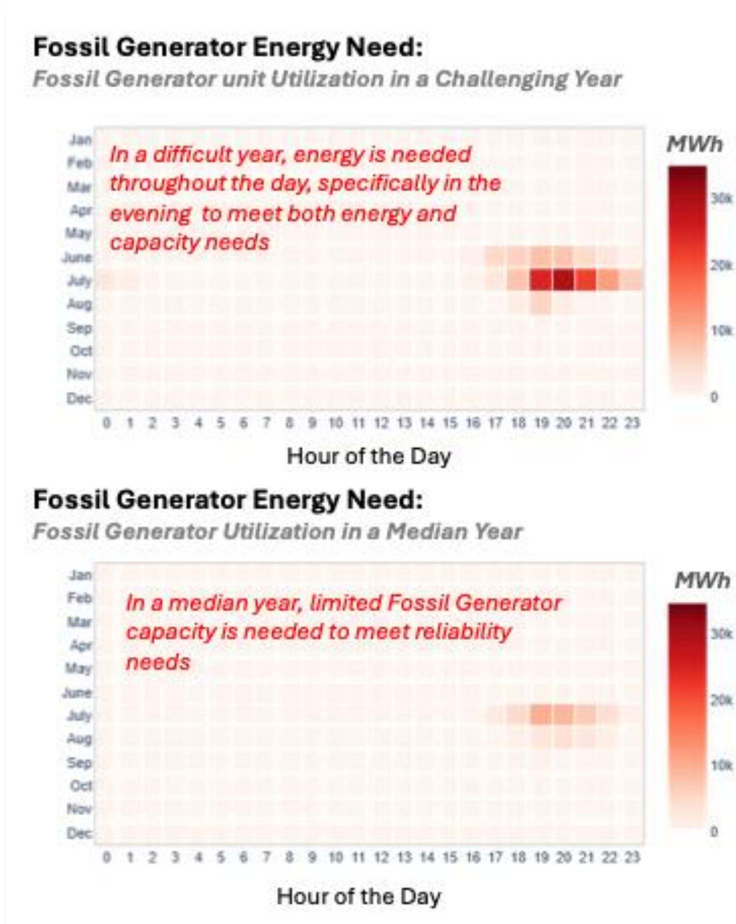
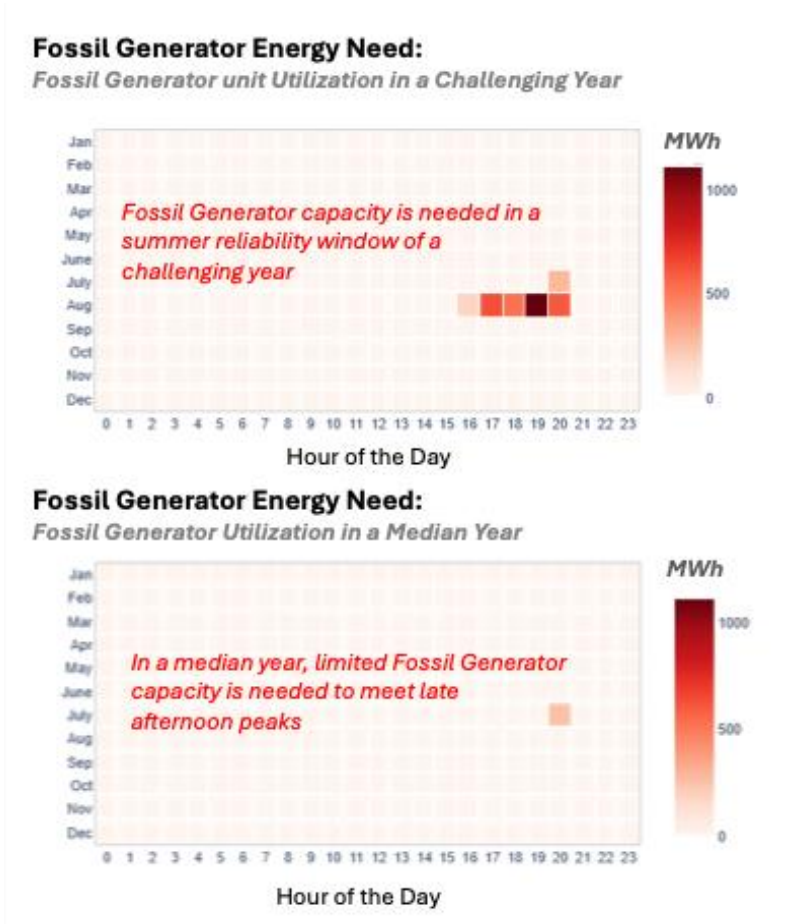


Figure 5-40: LRZ 4 Expected Unserved Energy Without Fossil Generators (If Capacity is Not Replaced)



5.4.4. No New Illinois Gas Case Results

In the No New Illinois Gas case, candidate CCGT and CT options within Illinois are disabled. However, firm capacity imports from neighboring states are still allowed from out of state gas units. All other inputs and assumptions are identical to the Base case.

Figure 5-41 and Figure 5-42 highlight the differences in selected resource capacity between the Base and No New Illinois Gas cases for the ComEd zone and MISO LRZ 4, respectively. The largest differences occur in the ComEd zone, where in the Base case large volumes of in-state peaking capacity were selected for system reliability. In the early 2030s, the ComEd zone exhausts its ability to import firm capacity up to the CETL limit (8.1 GW of nameplate out-of-state gas capacity). Consequently, by 2034, the ComEd zone faces an accredited capacity need of 4.5 GW. Because of the assumed availability of nuclear SMRs (1 GW is first available in 2035 and 3 GW in 2040), the only scalable accredited capacity option available is batteries. As a result, the model selects 17.2 GW of batteries by 2035 and 33.5 GW by 2040 in the ComEd zone to maintain resource adequacy. By 2045, when the mid-term availability constraints are relaxed, new nuclear capacity totaling 7.5 GW is selected in the ComEd zone as the cheapest accredited capacity resource.

Figure 5-41: ComEd Zone Selected Nameplate Capacity (GW) | No New Illinois Gas Case

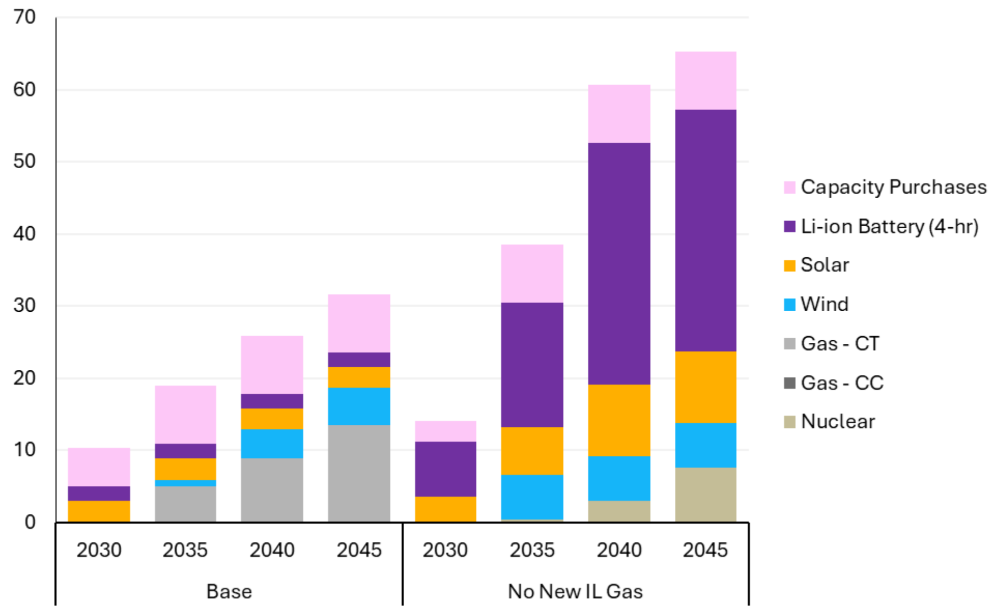


Table 5-21: ComEd Zone Selected Nameplate Capacity (GW) | No New Illinois Gas

Technology	Base				No New Illinois Gas			
	2030	2035	2040	2045	2030	2035	2040	2045
Nuclear	-	-	-	-	-	0	3	8
Gas - CC	-	-	-	-	-	-	-	-
Gas - CT	0	5	9	13	-	-	-	-
Wind	0	1	4	5	-	6	6	6
Solar	3	3	3	3	4	7	10	10
Li-ion Battery (4-hr)	2	2	2	2	8	17	34	34
Capacity Purchases	5	8	8	8	3	8	8	8

Figure 5-42: MISO LRZ 4 Selected Nameplate Capacity (GW) | No New Illinois Gas Case

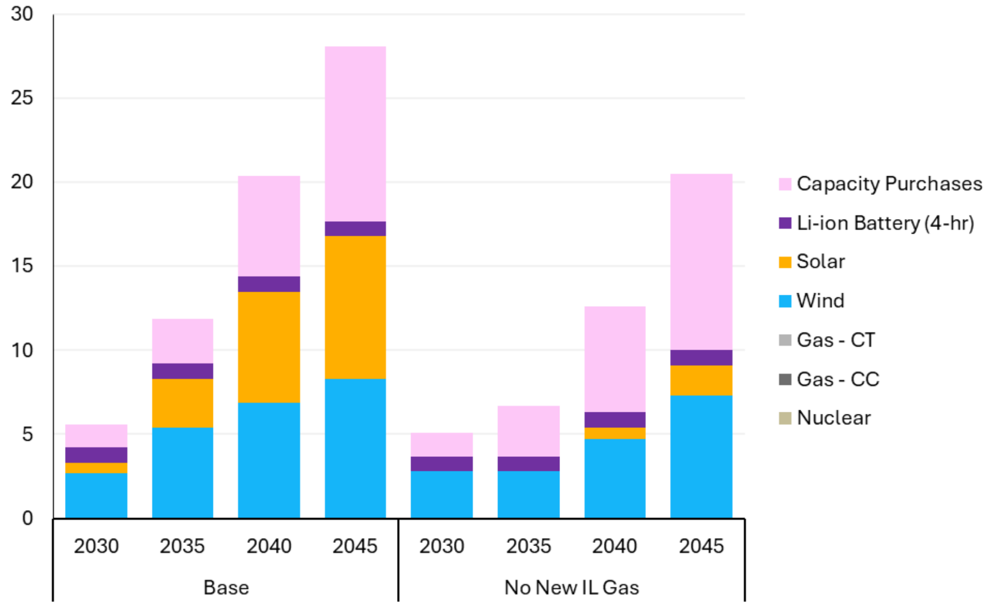


Table 5-22: MISO LRZ 4 Selected Nameplate Capacity (GW) | No New Illinois Gas Case

Technology	Base				No New Illinois Gas			
	2030	2035	2040	2045	2030	2035	2040	2045
Nuclear	-	-	-	-	-	-	-	-
Gas - CC	-	-	-	-	-	-	-	-
Gas - CT	-	-	-	-	-	-	-	-
Wind	3	5	7	8	3	3	5	7
Solar	1	3	7	9	-	-	1	2
Li-ion Battery (4-hr)	1	1	1	1	1	1	1	1
Capacity Purchases	1	3	6	10	1	3	6	10

The annual dispatch comparisons between the two cases are presented in Figure 5-43 and Figure 5-44 below. In MISO LRZ 4, the relocation of roughly 7 GW of solar resources into the ComEd zone reduces the in-zone solar generation and net annual exports by 14 TWh and 17 TWh, respectively. Meanwhile, in the ComEd zone, nuclear generation grows from 90 TWh in 2030 to 161 TWh in 2045 due to capacity needs; this causes the ComEd zone to behave as a net exporter, which does not occur in other cases studied in this report.

Figure 5-43: ComEd Zone Annual Generation (TWh) | No New Illinois Gas Case

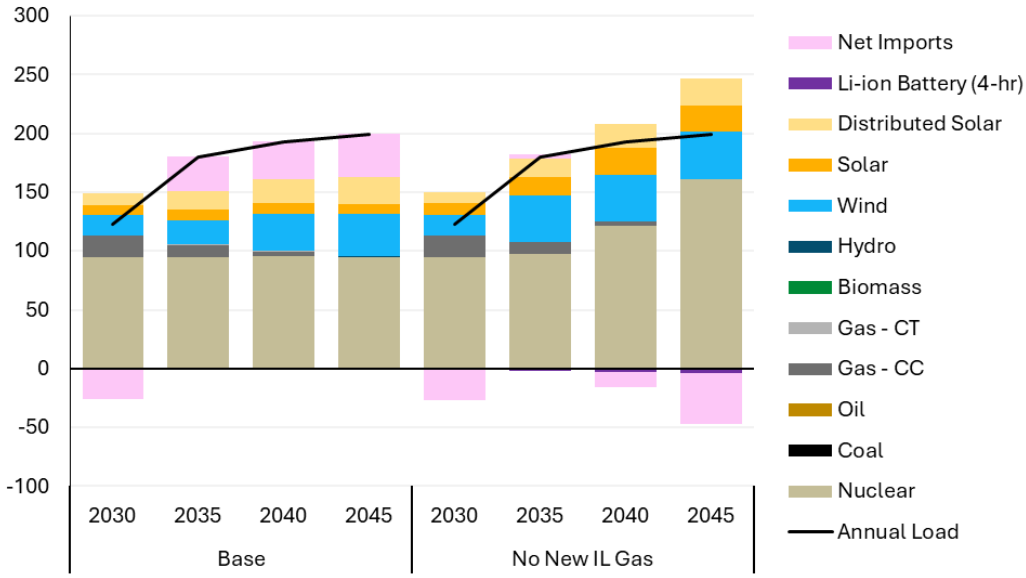


Table 5-23: ComEd Zone Annual Generation (TWh) | No New Illinois Gas Case

Technology	Base				No New Illinois Gas			
	2030	2035	2040	2045	2030	2035	2040	2045
Nuclear	95	95	95	95	95	98	122	161
Gas - CC	18	10	4	0	18	9	3	-
Gas - CT	-	1	1	0	-	-	-	-
Biomass	0	0	0	0	0	0	0	0
Hydro	0	0	0	0	0	0	0	0
Wind	18	21	32	36	18	39	40	40
Solar	8	8	8	8	10	16	22	22
Distributed Solar	10	16	21	23	10	16	21	23
Li-ion Battery (4-hr)	(0)	(0)	(0)	(0)	(1)	(2)	(3)	(4)
Net Imports	(26)	29	31	37	(26)	3	(13)	(43)
Annual Load	123	180	192	199	123	180	192	199

Figure 5-44: MISO LRZ 4 Annual Generation, TWh

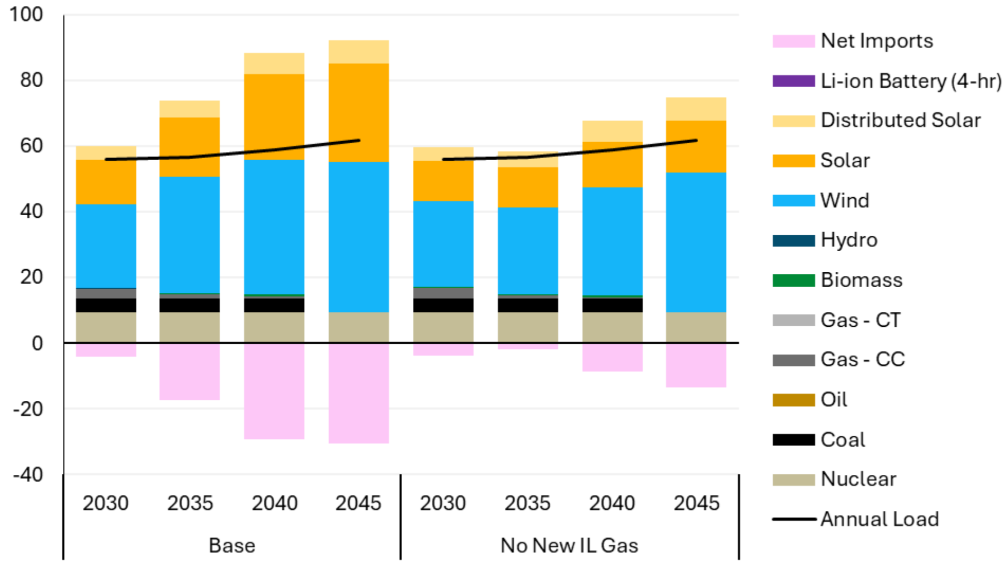


Table 5-24: MISO LRZ 4 Annual Generation, TWh

Technology	Base				No New Illinois Gas			
	2030	2035	2040	2045	2030	2035	2040	2045
Nuclear	9	9	9	9	9	9	9	9
Coal	4	4	4	-	4	4	4	-
Gas - CC	3	1	1	-	3	1	1	-
Gas - CT	-	-	-	-	-	-	-	-
Biomass	0	0	0	0	0	0	0	0
Hydro	0	0	0	0	0	0	0	0
Wind	26	35	41	46	26	26	33	42
Solar	14	18	26	30	12	12	14	16
Distributed Solar	4	5	6	7	4	5	6	7
Li-ion Battery (4-hr)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Net Imports	(4)	(17)	(29)	(30)	(4)	(2)	(8)	(13)
Annual Load	56	57	59	62	56	57	59	62

5.4.5. Illinois Net Zero Case Results

The Illinois Net Zero case illustrates a future scenario where Illinois mandates net-zero carbon emissions by 2045. This policy is assumed to be achieved in three ways:

1. All candidate in-state gas resources are assumed to convert to a zero-carbon fuel (e.g. green hydrogen or renewable natural gas) in 2045
2. Illinois is required to function as a net exporter of electricity on an annual basis starting in 2045, ensuring no net emissions are imported into the State
3. Selection of firm import capacity from out-of-state gas is disallowed in all years (2030-2045).

As we have seen in the Base case and other scenario results, it is very possible for Illinois to achieve very low in-state carbon emissions without additional policy. The Base case already featured very low fossil fuel generation, and imported roughly 7 TWh of electricity in 2045, meaning that only modest amounts of incremental renewable energy capacity would be needed to achieve the additional constraints defined in (1) and (2).

At first glance, the resource buildout in this case may seem counterintuitive—despite being the strictest emissions policy modeled, this case results in more new gas capacity being built in Illinois than in the Base case. However, this outcome is a direct result of the requirement to meet all in-state reliability needs without relying on out-of-state fossil generation, combined with the model's ability to select clean-fuel capable in-state gas resources. These gas units are not selected to increase fossil fuel reliance, but rather because they represent cost-effective reliable capacity that meets CEJA and net-zero compliance by being capable of operating on zero-carbon fuels in 2045. In contrast, scenarios that restrict all new gas development must rely more heavily on expensive nuclear and large-scale battery buildouts, which drive up costs and total resource buildout, as batteries have nearly saturated their capacity value.

As shown in Figure 5-45 and Figure 5-46 for the ComEd zone and MISO LRZ 4, the Illinois Net Zero case is largely comparable to the Base case, with the primary exception being that all firm capacity imports have been converted to zero-carbon-fuel capable, in-state gas capacity options. These gas plants operate at very low capacity factors and are essentially selected to maintain resource adequacy.

Figure 5-45: 2045 ComEd Zone Selected Nameplate Capacity (GW) | Base vs. No New Illinois Gas vs. Net Zero

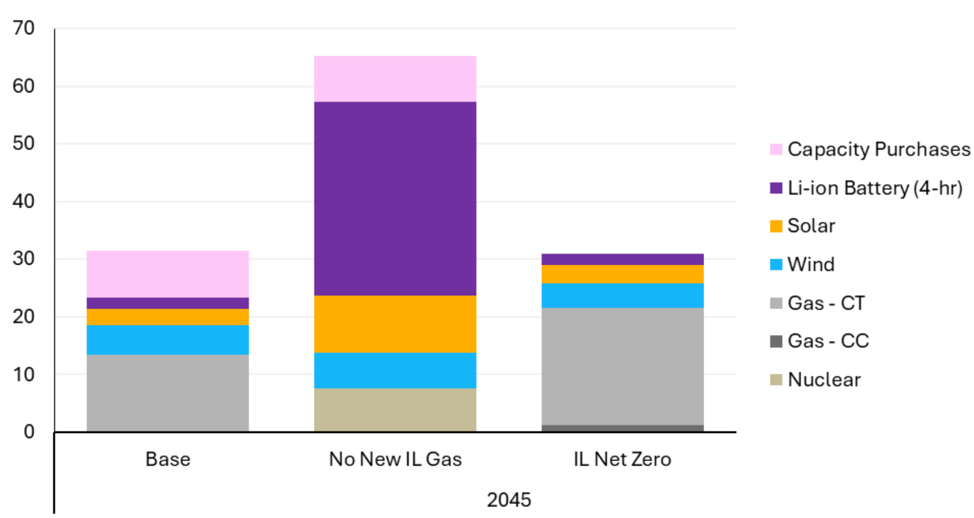


Table 5-25: 2045 ComEd Zone Selected Capacity (GW) | Base vs. No New Illinois Gas vs. Net Zero

Technology	Base Case	No New Illinois Gas	Illinois Net Zero
Nuclear	-	8	-
Gas – CC	-	-	1
Gas – CT	13	-	20
Wind	5	6	4
Solar	3	10	3
Li-ion Battery (4-hr)	2	34	2
Capacity Purchases	8	8	-

Figure 5-46: 2045 MISO LRZ 4 Selected Nameplate Capacity (GW)

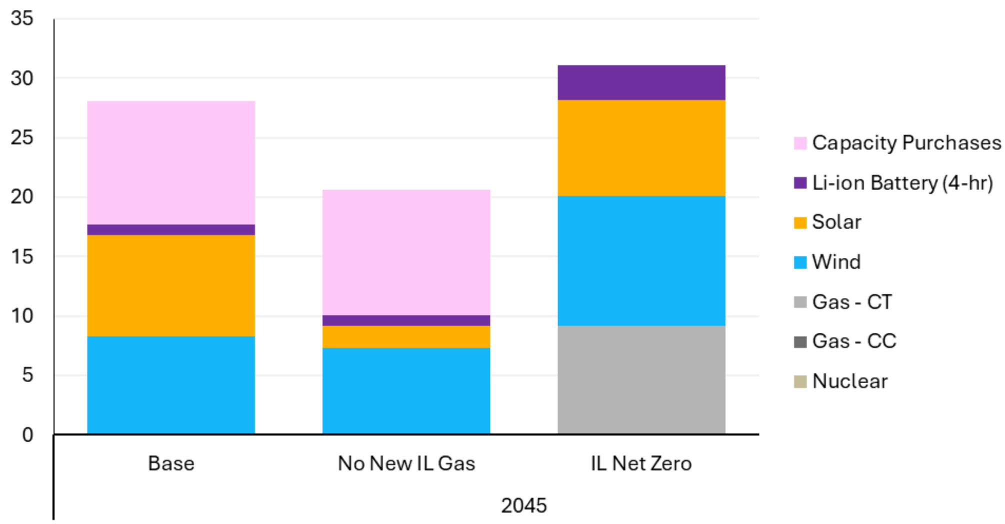


Table 5-26: 2045 MISO LRZ 4 Selected Nameplate Capacity (GW)

Technology	Base Case	No New Illinois Gas	Illinois Net Zero
Nuclear	-	-	-
Gas – CC	-	-	-
Gas – CT	-	-	9
Wind	8	7	11
Solar	9	2	8
Li-ion Battery (4-hr)	1	1	3
Capacity Purchases	10	10	-

Comparing system dispatch between these three cases, the results in the ComEd zone are nearly identical between Base and Illinois Net Zero. In MISO LRZ 4, additional storage capacity is selected and cycled to reduce solar curtailment and ensure that the State in aggregate can function as a net exporter. As an additional comparison point, the No New Illinois Gas case also functions as a net exporter with the large volume of nuclear resources selected in MISO LRZ 4; however, the cost of this scenario would be significantly higher than either of the other scenarios presented.

Figure 5-47: 2045 ComEd Zone Annual Generation (TWh) | Base vs. No New Illinois Gas vs. Net Zero

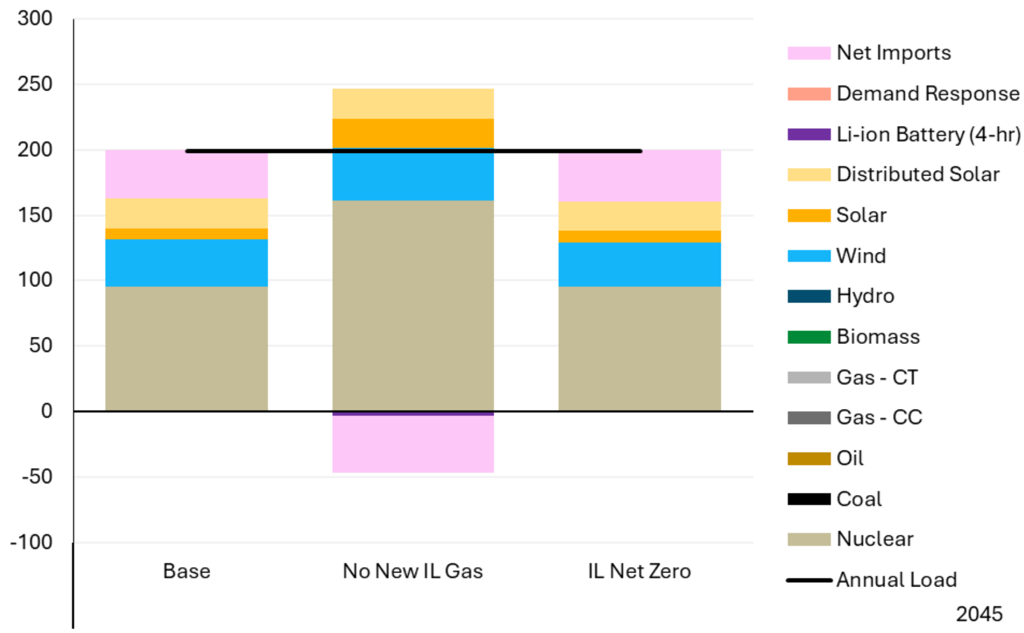


Table 5-27: 2045 ComEd Zone Generation (TWh) | Base vs. No New Illinois Gas vs. Net Zero

Technology	2045	2045	2045
Nuclear	95	161	95
Gas - CC	0	-	0
Gas - CT	0	-	0
Biomass	0	0	0
Hydro	0	0	0
Wind	36	40	33
Solar	8	22	9
Distributed Solar	23	23	23
Li-ion Battery (4-hr)	(0)	(4)	(0)
Net Imports	37	(43)	39

Figure 5-48: 2045 MISO LRZ 4 Generation (TWh) | Base vs. No New Illinois Gas vs. Net Zero

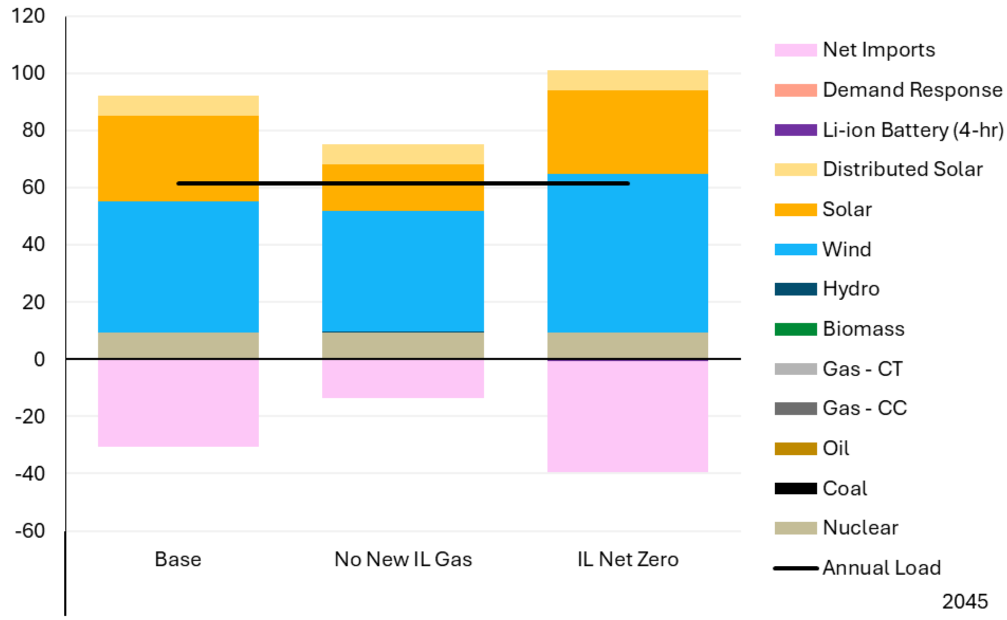


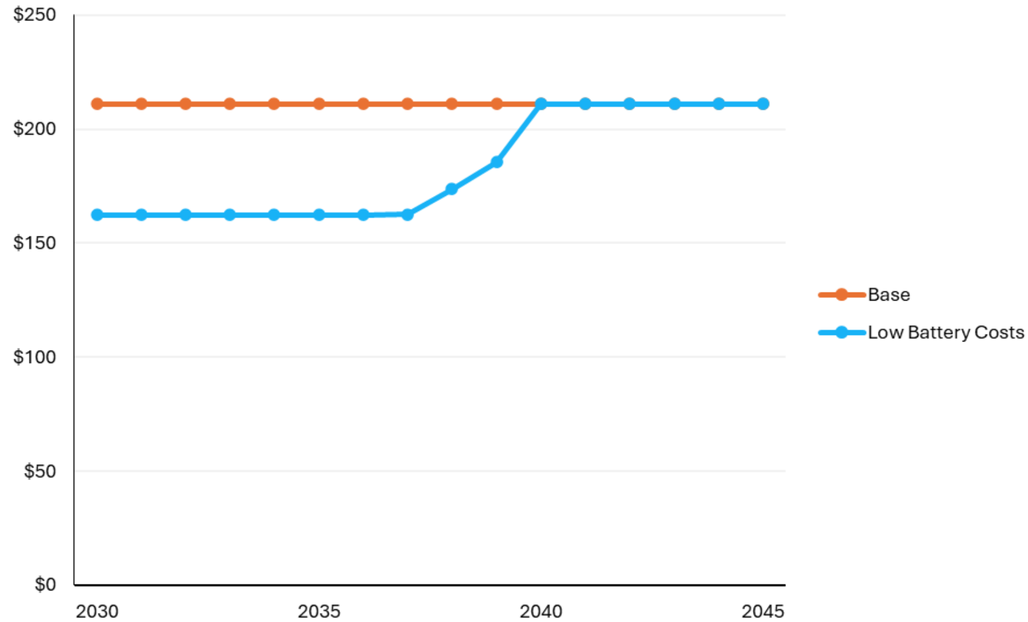
Table 5-28: 2045 MISO LRZ 4 Generation (TWh) | Base vs. No New Illinois Gas vs. Net Zero

Technology	2045	2045	2045
Nuclear	9	9	9
Gas - CC	-	-	-
Gas - CT	-	-	-
Biomass	0	0	0
Hydro	0	0	0
Wind	46	42	55
Solar	30	16	29
Distributed Solar	7	7	7
Li-ion Battery (4-hr)	(0)	(0)	(1)
Net Imports	(30)	(13)	(39)

5.4.6. Low Battery Costs Case Results

In the Low Battery Costs case, the cost trajectory applied to batteries in all zones is reduced to represent an optimistic, low-cost bookend, as shown in Figure 5-49 below. New battery builds in the Low Battery Costs scenario are 23% lower than the base case in 2030.

Figure 5-49: 4-hr Battery Nominal Levelized Fixed Cost. $/kW/yr



In the Base case, batteries were already the cheapest accredited capacity resource in 2030 due to the near-term scarcity pricing assumed for candidate gas resources. With this context, the Low Battery Costs case is useful for approximating a high bookend of battery capacity selected for Illinois by 2030.

The Low Battery Costs case results are compared to the Base case in Figure 5-50 and Figure 5-51. Aside from the adjusted battery cost trajectory, all other inputs are identical between the two cases. In this case, the battery capacity selected grows from 0.9 GW to 3.7 GW in MISO LRZ 4, supplanting out-of-state capacity purchases, but remains the same in the ComEd zone. In the ComEd zone, the decrease in battery cost is not enough to become more economic than out-of-state capacity purchases and total 2045 selected capacity remains nearly identical between cases, with some shift in wind & solar selections. In total, the amount of cost-optimal battery selections in Illinois could range from 3 GW (Base) to 6 GW (Low Battery Costs).

Figure 5-50: ComEd Zone Selected Nameplate Capacity (GW) | Low Battery Cost Case

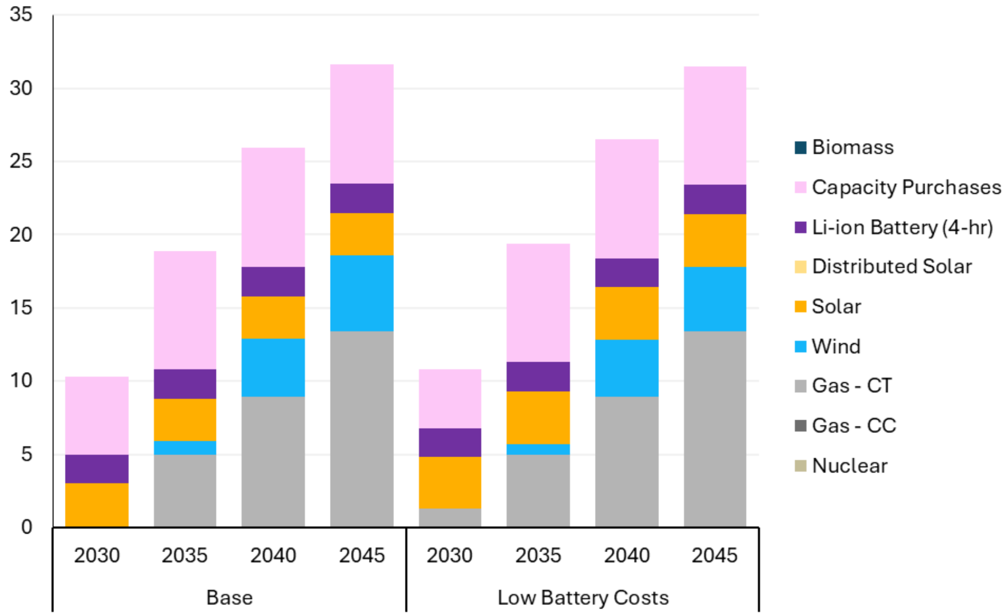


Table 5-29: ComEd Zone Selected Nameplate Capacity (GW) | Low Battery Cost Case

	Base				Low Battery Costs			
Technology	**2030**	**2035**	**2040**	**2045**	**2030**	**2035**	**2040**	**2045**
Nuclear	-	-	-	-	-	-	-	-
Gas - CC	-	-	-	-	-	-	-	-
Gas - CT	0	5	9	13	1	5	9	13
Wind	0	1	4	5	-	1	4	4
Solar	3	3	3	3	4	4	4	4
Li-ion Battery (4-hr)	2	2	2	2	2	2	2	2
Capacity Purchases	5	8	8	8	4	8	8	8

Figure 5-51: MISO LRZ 4 Selected Nameplate Capacity (GW) | Low Battery Cost Case

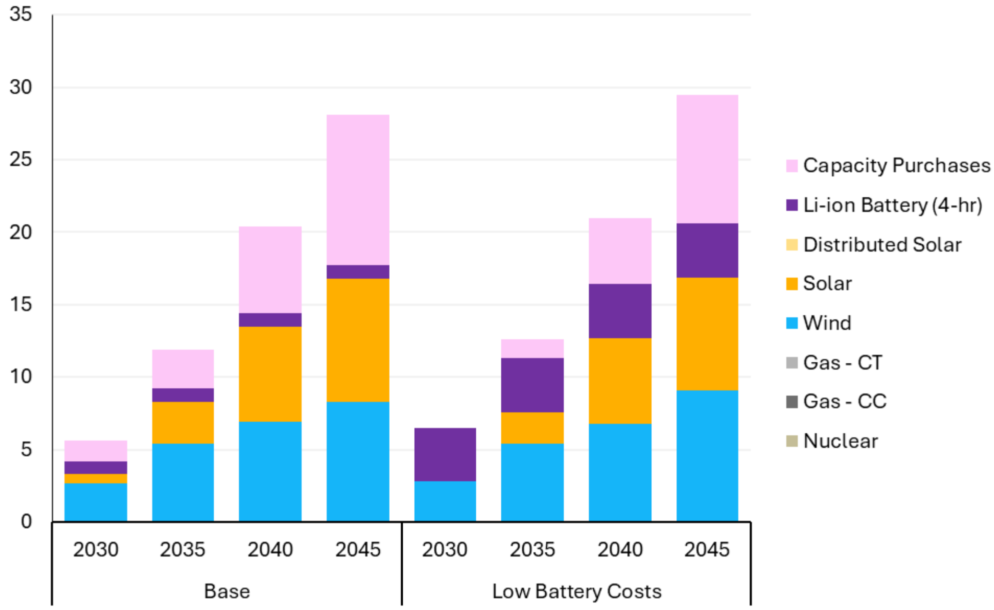


Table 5-30: MISO LRZ 4 Selected Nameplate Capacity (GW) | Low Battery Cost Case

	Base				Low Battery Costs			
Technology	**2030**	**2035**	**2040**	**2045**	**2030**	**2035**	**2040**	**2045**
Nuclear	-	-	-	-	-	-	-	-
Gas - CC	-	-	-	-	-	-	-	-
Gas - CT	-	-	-	-	-	-	-	-
Wind	3	5	7	8	3	5	7	9
Solar	1	3	7	9	-	2	6	8
Li-ion Battery (4-hr)	1	1	1	1	4	4	4	4
Capacity Purchases	1	3	6	10	-	1	5	9

The scenarios considered within this study illustrate a central finding—that there are pathways for Illinois to maintain reliability while achieving renewable energy and decarbonization trajectories using available commercial technologies. The scenarios considered here illustrate that thermal generation is an important source of resource adequacy alongside new battery storage resources, while new renewable energy resources (wind and solar) can continue to drive reductions in carbon emissions from electrical energy consumed in Illinois. The scenarios evaluated in this study do not constitute an exhaustive or comprehensive set of potential scenarios Illinois may face in the future, nor do these portfolio results by themselves indicate a required resource trajectory for the state. The Base Case scenario and others presented in this report are intended to provide an illustration of the nature of the challenges that Illinois faces with resource adequacy and clean energy targets in the future and provide constructive guidance on the nature of the potential resource solutions to meet these challenges. More comprehensive portfolio analysis and additional scenarios will be an important component of any forward planning or procurement for Illinois in the future, including a future Integrated Resource Planning exercise.

6. Cost of Resource Adequacy in Illinois

This report presents an assessment of resource adequacy including the associated drivers, trends, and challenges related to resource adequacy for electricity service to Illinois consumers. The analysis in this report is intended to provide the framework for characterizing and understanding the resource adequacy needs and challenges facing Illinois and how these may evolve over time. The portfolio analysis in Chapter 5 (State of Resource Adequacy) specifically is intended to illustrate potential resource options and tradeoffs for how resource adequacy needs could be addressed alongside Illinois state energy and environmental policy goals. The resource portfolios presented are not intended to represent all likely or possible scenarios, nor are they intended to represent a proposed resource plan or policy decision.

To support the report's objectives of providing context for future decision-making processes, this chapter presents a conceptual framework and real-world context for how the costs of resource adequacy are borne by Illinois consumers. The principles and market mechanisms described in this chapter represent the relevant perspectives and levers for assessing the costs of resource adequacy for Illinois electricity consumers which should be one of the core components of future analysis for resource planning, procurement, or related policy decisions by the state of Illinois.

As described in Chapter 5, the costs of resource adequacy in MISO and PJM are predominantly backstopped by the capacity market and the prices determined through each RTO's auction. These auctions establish the prices that loads pay for their share of the system's total reliability requirement when such loads have not contracted or otherwise directly provided for physical capacity or engaged in capacity price hedging. The capacity markets in both RTOs provide the principal price signal for the development of new capacity resources and the retention or retirement of existing resources, but the settlement volumes of capacity are quite different between the PJM and MISO auctions. In MISO, most of the resource adequacy capacity (MW) is compensated outside of the auction through utility resource ownership or bilateral contracts with generation owners, while in PJM, a larger share of total resources is compensated directly through the auction settlements. Each RTO employs some additional compensation mechanisms for reliability beyond the RTO capacity auctions, but these other mechanisms are small in scale and are typically limited in use.[222]

Customers in Illinois are served by municipal utilities, electric cooperatives, ARES, or electric utilities. This includes electric utilities that rely on IPA procurements when acting as the default service provider for customers living in the regulated service territories of ComEd, Ameren, and MidAmerican utilities. The default service is service provided to customers who do not select an ARES for service. Electricity supply prices are also backstopped by the RTO wholesale markets and LMPs for energy. In a competitive equilibrium, the typical retail customer in Illinois can expect to pay the wholesale market price for energy and capacity in their market zone. The actual composition of costs as translated into retail customer generation rates is comprised of additional components such as risk premiums and working capital needs; however, the underlying energy and capacity cost components are largely consistent regardless of the supplying entity because they are anchored to market prices.

Retail electric suppliers have the choice to build or buy energy and capacity from existing or new resources or enter into financial contracts to manage market price risk. Under the capacity markets in MISO and PJM, LSEs, including those serving customers in Illinois, have the option of replacing all or a portion of their capacity obligation with owned or contracted resources. If an LSE does so, they would pay the costs of these resources directly (through capital and operating costs or through contract settlements) rather than the prevailing capacity auction price. If new resources are developed by independent power producers, Illinois LSEs will only benefit from these resources through their effect on the marginal price of energy, ancillary services, and capacity prices, unless these resources are directly contracted to Illinois LSEs—in which case the purchasing LSE(s) would pay the contract costs of the resources instead of the market prices for the quantity of energy and capacity provided, in addition to the marginal price impacts in the impacted zone(s).

New resources—from wind and solar to batteries, gas turbines, and others—usually heavily depend on wholesale market revenues for energy and capacity. These new resources will only be financed and developed if total expected future revenues meet or exceed total costs (including returns on invested capital). Most independent project developers and financiers also require a degree of revenue certainty from contracts and hedges, and greater revenue

[222] For example, both RTOs have established cost-based contracts which can be used bilaterally between the RTO and specific generators to provide revenue to keep a generator online if the RTO deems the generator to be necessary for local or system reliability and the generator would otherwise retire without the contract support. In PJM, these arrangements are known as Reliability Must-Run (RMR) contracts and in MISO they are called System Support Resource (SSR) contracts.

certainty also allows for lower total costs of capital including a higher share of project costs financed by debt.

LSEs may also benefit from price certainty in contracts with generators, which provide stable costs for their customers and a hedge against market price volatility—however, long term contracts inherently carry risk as well as benefits for LSEs because contracted prices may be lower or higher than future wholesale market prices, resulting in cost savings or increases for their customers. Hence, LSEs in general may be expected to sign long term contracts with new resources (instead of financial hedges or short term contracts with existing resources) only if the contract price for new resources is lower than expected future market prices, as LSEs must balance the potential benefits with the potential costs of longer term commitments.[223] Furthermore, because resource adequacy is a shared risk for all loads in each RTO market, the decisions of one LSE may affect the reliability and market prices of other LSEs in the broader market. For example, a new resource may be paid for by one or more LSEs under contract, but this resource coming online will also benefit all loads in the market by improving the total resource adequacy supply (and potentially reducing capacity market prices, all else being equal).

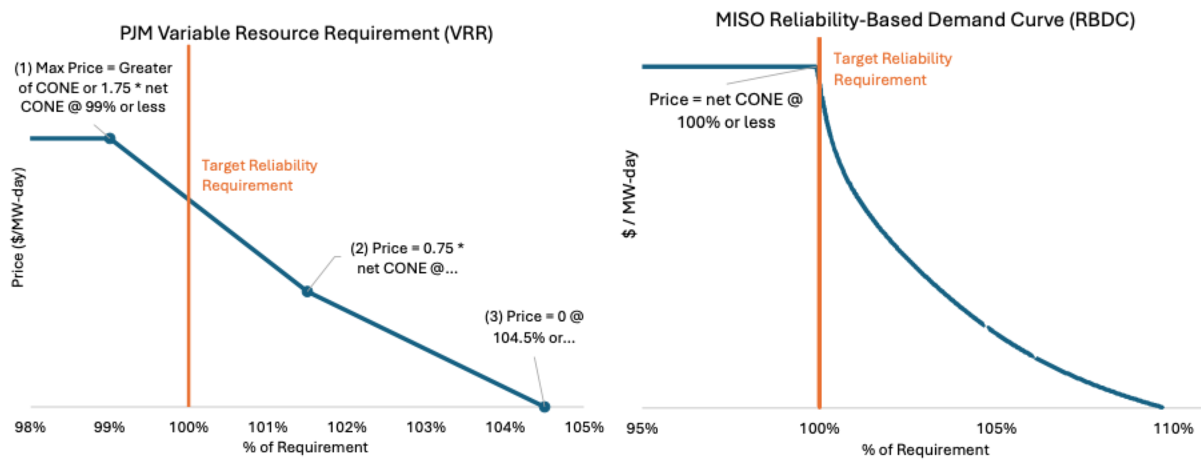
The load-resource balance projections for PJM and MISO presented in Section 4.2 show that over a range of expectations, both RTOs are expected to have resource adequacy shortfalls by 2030 without additional resources beyond those currently in development. Under the scenarios of additions, retirements, and delays considered, the resource adequacy shortfall ranges from 10-26 GW in PJM and from 7-21 GW in MISO in 2030-2031. In PJM, the capacity auction demand curve is defined to hit the maximum auction price at 99% or less of the resource requirement. In MISO, the reliability based demand curve (RBDC) is designed to be at the price cap when the system is at 100% or less of the reliability requirement. Under both market designs, these levels of resource adequacy shortfalls would put both capacity markets at the price cap without new resource development by 2030.

The portfolio analysis presented in Chapter 5 defines various potential portfolios of new resources which could meet the evolving reliability needs of both RTOs (and Illinois zones) through 2045. If one of these portfolios is developed (or an alternative portfolio with similar reliability value), the result would be both capacity markets clearing at each RTO's target reliability requirement over the forecast period. In this case, the reference price of capacity

[223] In Illinois when the LSE is a utility providing default service, the approaches defined to secure supply, including in some instances capacity, are defined through the IPA's Electricity Procurement Plan. The default service utility is then obligated to execute the resulting contract award from IPA's procurement following ICC review and approval. When the LSE is an ARES, the exact approach and contract structure is unique to each ARES including resource type, term of agreement, and cost and risk premiums.

for all customers in Illinois (and more broadly in each RTO) would be the capacity price set by PJM and MISO auction demand curves when the system is at the reliability target.

Figure 6-1: PJM and MISO Capacity Auction Demand Curves



Sources: "PJM Manual 18: PJM Capacity Market Revision: 61," PJM (July 2025): https://www.pjm.com/-/media/DotCom/documents/manuals/m18-redline.pdf.
"Planning Resource Auction: Results for Planning Year 2025-26," MISO (April 2025): https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250529_Corrections694160.pdf.

Both PJM and MISO use a new gas-fired combustion turbine (CT) as the reference resource to set the Cost of New Entry (CONE) and net CONE values on the auction demand curve.[3] Future clearing prices at the target reliability requirement can be estimated for both RTOs by estimating future net CONE values for a gas-fired CT—in this case, the MISO price will equal the net CONE estimate and the PJM price will equal a linear interpolation between points (1) and (2) on the VRR. The table below illustrates the potential capacity costs for Illinois electric customers in the ComEd and LRZ 4 zones from 2030-2045 in constant real dollars, based on the projected peak load and planning reserve margin requirements for both zones and assuming future CONE values remain constant at the latest published values from PJM and MISO.

Table 6-1: Projected Capacity Market Costs for ComEd and LRZ 4 Zones 2030-2045

	2025 /2026	2026 /2027	2030	2035	2040	2045
PJM CONE ($/MW-day)	$452	$506	$530	$530	$530	$530
PJM Net CONE ($/MW-day)	$229	$212	$243	$243	$243	$243
PJM ComEd Zone Price ($/MW-day)	$270	$329	$391	$391	$391	$391
ComEd Zone Reliability Requirement (MW)	21,814	20,272	27,172	34,467	35,828	36,481
ComEd Zone Capacity Market Cost ($ billion / year)	**$2.1**	**$2.4**	**$3.9**	**$4.9**	**$5.1**	**$5.2**
MISO North/Central CONE ($/MW-day)	$349	$366	$366	$366	$366	$366
MISO N/C Net CONE ($/MW-day)	$219	$222	$222	$222	$222	$222
MISO LRZ 4 Price ($/MW-day)	$213	N/A	$222	$222	$222	$222
LRZ 4 Reliability Requirement (MW)	9,430	N/A	11,121	11,996	13,029	13,950
LRZ 4 Capacity Market Cost ($billion/year)	**$0.7**	**N/A**	**$0.9**	**$1.0**	**$1.1**	**$1.1**

Notes:
a. All dollar values for projection years (2030, 2035, 2040, and 2045) are in constant real 2026 dollars. Values for pending or cleared delivery years (2025/2026 and 2026/2027) are in nominal dollars from the auction year.
b. Projected CONE and net CONE values are assumed to remain constant from the latest published values from PJM (for the 2027/2028 auction) and MISO (for the 2026/2027 auction).
c. Reliability requirements for ComEd and LRZ 4 zones for pending or cleared auction delivery years are equal to the capacity cleared in the auctions (MW), while projected reliability requirements from 2030-2045 are based on peak load and planning reserve margin requirement projections aligned with the Base Case portfolio modeling presented in Chapter 5.
d. MISO capacity prices are annualized from a weighted average of the four seasonal prices and requirements. The LRZ 4 reliability requirement is expressed as the summer requirement in future years.
Sources:
1. "2026/2027 Base Residual Auction Report," PJM, page 17 (July 22, 2025): https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2026-2027/2026-2027-bra-report.pdf.
2. "Planning Resource Auction: Results for Planning Year 2025-26," MISO (April 2025): https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250529_Corrections694160.pdf.
3. "2026/2027 RPM Base Residual Auction Planning Period Parameters," PJM, page 5 (May 9, 2025): https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2026-2027/2026-2027-planning-period-parameters-for-base-residual-auction-pdf.pdf.
4. "MISO Cost of New Entry (CONE) and Net CONE Calculation for Planning Year 2025/2026," MISO, Resource Adequacy Subcommittee (RASC), pages 11-18 (September 23, 2024): https://cdn.misoenergy.org/20240923%20RASC%20Item%2003%20CONE%20and%20Net%20CONE%20Update649247.pdf.
5. "Filing of Midcontinent Independent System Operator, Inc. Regarding Local Resource Zone CONE and Net CONE Calculations," MISO, 2025-10-15 Docket No. ER26-139-000 (October 15, 2025): https://cdn.misoenergy.org/2025-10-15%20Docket%20No.%20ER26-139-000722804.pdf, Attachments B-C.

Under these assumptions, as provided in Table 6-1, Illinois customers in ComEd and Ameren market zones could pay $3.9 and $0.9 billion per year respectively for capacity by 2030, with the increase in total costs largely derived from increased requirements in both zones resulting from peak load growth. The capacity costs for customers in the ComEd zone also rise because the expected auction prices at the PJM reliability target are higher (at $391 per MW-day) than the capacity price cap that is in place ($329 per MW-day) for the 2026/2027 and 2027/2028 auctions. In the auction results for delivery year 2026/2027, prices cleared just below the reliability requirement (excluding FRR resources), and PJM published that prices would have cleared at $389 per MW-day if the cap had not been in effect.[224]

These capacity cost projections for Illinois consumers likely represent an optimistic, lower-end view of the potential future costs of capacity in the RTO markets. The pressures of load growth and generator retirements, combined with the challenges of developing new capacity resources at scale over a limited time horizon all create conditions under which resource adequacy is more likely to be tight (close to target requirements) than in surplus. The costs of developing new capacity resources are also under many pressures and future CONE and net CONE values may increase rather than stay constant as these projections assume. The load forecasts in this report, while inclusive of material levels of new data center load growth, still represent lower amounts of data center loads than the total estimates published by either PJM or MISO. Data center loads could potentially be more responsive to peak hours in the future, which could lessen the impacts of these loads on resource adequacy requirements, but total data center loads could also be higher than the trajectories assumed in this report.

The reliability of the electrical grid is vitally important to the economy, critical services such as health care and emergency response, and to everyday people's lives. The costs of developing new reliability resources are also significant, as are the costs of capacity under the RTO market designs when the systems are close or short of the resource adequacy standards. The state of Illinois has an important policy role to play in evaluating a range of potential solutions, balancing costs and risks and other policy concerns, and supporting solutions that can create stable, reliable, and affordable electric service available to Illinois consumers for years to come.

[224] "2026/2027 Base Residual Auction Report," PJM, page 17 (July 22, 2025): https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2026-2027/2026-2027-bra-report.pdf.

7. Findings and Next Steps

Illinois is entering a period of significant transformation in its electric power system. State climate policies, evolving RTO market conditions, significant load growth, and challenges with new resource development collectively point to a tightening reliability outlook in the near to medium term. This Resource Adequacy Study, developed jointly by the IPA, ICC, and IEPA, assesses these dynamics and identifies pathways to ensure that Illinois can meet both its climate and reliability objectives. Based on extensive analysis of RTO conditions, state policy requirements, and forward-looking resource needs, several key findings emerge.

7.1. Key Findings

7.1.1. Illinois' resource adequacy is shaped by state policy and regional grid conditions

Illinois' clean energy policies, including CEJA's emissions limits for thermal generation and statewide renewable energy targets, play a central role in shaping the future resource mix in Illinois. However, resource adequacy in Illinois is fundamentally dependent on the resource adequacy of the greater MISO and PJM grids. Because both RTOs are projected to experience a significant need for new capacity by 2030, Illinois' own ability to import energy and capacity is constrained by the regional supply-demand balance. Illinois zones, effectively comprised of ComEd in PJM and LRZ4 in MISO, remain reliable only when (1) local in-state resources and firm imports meet zonal requirements, and (2) the RTOs are themselves resource adequate.

Emerging RTO-wide conditions therefore directly affect the reliability and cost exposure of Illinois consumers. Even resources located outside Illinois materially influence the state's ability to meet accredited capacity needs and to avoid high capacity market prices.

7.1.2. Both MISO and PJM face a risk of resource adequacy shortfalls by 2030

The study finds that both RTOs are expected to require substantial new resource additions to meet projected reliability requirements by 2030 before accounting for Illinois-specific policy-driven retirements. Several trends amplify this reliability challenge:

- Load growth is accelerating, driven by data centers, transportation demand, and industrial expansion.
- Many coal, gas, and oil units are planned to retire across both RTOs due to age, economics, and emissions limits.

- New gas-fired generation will be slow to come online in both RTOs, in part due to long equipment lead times (5–7 years for gas turbines) and significant barriers to siting and permitting.
- Renewables and batteries generally have lower effective capacity values than dispatchable thermal plants, requiring that a greater quantity of MW be added to meet each incremental MW of reliability need.
- Wind, solar, and storage projects face development challenges from long interconnection queues, transmission constraints, supply chain disruptions, tariffs, and domestic content requirements for tax credit eligibility.

These conditions create a credible risk of regional capacity shortages that would impact Illinois' future ability to import power during critical hours and may cause reliability issues in Illinois even if Illinois market zones have enough capacity to meet their zonal resource adequacy requirements as determined by the RTOs.

7.1.3. Illinois zones face their own resource adequacy gap by 2030 absent new development or increased imports

Before considering Illinois state policy and potential retirements, neither the ComEd zone nor MISO LRZ4 currently has sufficient in-state and planned resources to reliably meet 2030 requirements under several potential scenarios. As loads grow and existing units retire, the zones' reliance on imports is expected to increase. However, if regional RTOs themselves are short on capacity, imports may not be available.

Thus, Illinois will require new in-state resources and/or imported capacity to maintain reliability, particularly during tight system conditions.

7.1.4. Retirements of fossil-fueled generators increase Illinois' near-term reliability needs

If fossil generators retire on the statutory schedule established by CEJA and the capacity contributions of these generators are not replaced, Illinois zones could face higher capacity market prices in both MISO and PJM as supply tightens, with local zonal prices in LRZ3, LRZ4, and ComEd converging toward, or exceeding, prices in other RTO zones. At the same time, loss-of-load probabilities and expected unserved energy increase if new resources are not built in time to offset retiring units. Overall, these dynamics underscore that Illinois' reliability risk is driven primarily by the relationship between the pace of retirements and the pace at which new replacement resources can be developed—both within Illinois and in the broader regional markets.

7.1.5. Illinois can meet its climate goals while maintaining reliability, but only with substantial new resource additions

The state can successfully navigate both near-term reliability risks and longer-term decarbonization goals through a diversified resource strategy. This may include combining continued growth of new in-state wind and solar supported by IPA procurement programs, greater use of existing and planned transmission to import power from MISO and PJM when available, and the potential continued use of thermal generators as reliability assets even as their energy output declines with higher renewable penetration. This strategy may also require adding more short-duration battery storage and other flexible technologies to meet peak reliability needs, as well as developing new clean firm capacity resources to ultimately replace the reliability contribution provided by fossil generators in the long-term future, such as long-duration storage and other emerging zero-emission technologies.

The analysis reinforces that substantial new capacity from renewable, storage, and clean firm resources will be needed even if Illinois retains a portion of its existing thermal fleet. Though not a focus of this study, new resource planning should also consider the potential contributions from demand-side measures, including energy efficiency and demand response—especially the potential load flexibility of new large loads such as data centers given the importance of these loads in the forecast.

7.1.6. Key cost implications for Illinois consumers

While detailed cost modeling is outside the scope of this study, several high-level findings emerge:

1. Under the retail competition structure in Illinois, the costs that Illinois consumers pay for energy and resource adequacy are shaped by and anchored to the wholesale market prices within Illinois market zones in each RTO.
2. Illinois consumers primarily benefit from new resource development through the marginal impacts of new resources on wholesale energy and capacity prices within each Illinois market zone. Illinois consumers only benefit from cost savings or price stability from new resources if these resources are contracted to Illinois consumers (through one or more Illinois Load-Serving Entities). Such long-term contracts also carry risks that contract settlements could exceed future market prices. The potential benefits and risks of any long-term new resource contracts for Illinois consumers should be evaluated carefully through long term planning exercises.
3. Much of the physical reliability benefit of resources, including new resources, is shared with the broader RTO footprint due to regional market design.

4. If regional markets remain short, Illinois will face persistent high capacity prices even if it builds new resources in-state.

These findings point to the importance of aligning Illinois procurement strategies with regional market dynamics.

7.1.7. Conclusion

Illinois faces a tightening reliability environment driven by accelerated load growth, regional capacity shortages, and scheduled retirements under CEJA. However, Illinois can maintain reliability and continue advancing toward its clean energy goals if it accelerates development of new in-state resources, strategically manages retirements, and leverages transmission and regional coordination. This study demonstrates that proactive planning is essential to ensuring that Illinois consumers continue to receive reliable, affordable, and increasingly clean electricity during a period of rapid change in the regional power sector.

7.2. Mitigation Plan Development

As discussed above, the analysis contained herein is designed to examine the State's current progress toward its renewable energy resource development goals, the status of CO_2e and co-pollutant emissions reductions, the current status and progress toward developing and implementing green hydrogen technologies, and the current and projected status of electric resource adequacy and reliability throughout the State for the period beginning five years ahead. The information produced by the analysis can be used for, among other things, drawing conclusions as to whether data from the regional grid operators, the pace of renewable energy development, the pace of development of energy storage and demand response utilization, transmission capacity, and the CO_2e and co-pollutant emissions reductions required by Illinois law reasonably demonstrate that a resource adequacy shortfall will occur, including whether there will be sufficient in-state capacity to meet the zonal requirements of MISO LRZ 4 or the PJM ComEd Zone, per the requirements of the regional transmission organizations, or that the regional transmission operators determine that a reliability violation will occur during the time frame the study is evaluating.

With any forward-looking study, given that the future is uncertain and continuously changing, any assumptions used will not be exact. All care has been taken to identify assumptions that are likely to be sufficiently in line with actual experience as to provide useful results. The analysis includes examination of sensitivities in modeling results to modeling assumptions to address reasonably probable alternative futures. In this regard, the analysis informs but does not, and cannot, unequivocally answer whether a resource adequacy shortfall will occur.

The results here show circumstances under which a resource adequacy shortfall may or may not occur by 2030. Given there are circumstances under which a resource adequacy shortfall may occur, this report also identifies proposed solutions for such findings. While an initial set of proposed solutions are identified herein, future modeling and analysis is required to consider alternative scenarios and develop additional solutions for later consideration and/or approval by the ICC.

For next steps, Section 9.15(o) of the Environmental Protection Act provides that should this study "reasonably demonstrate . . . that a resource adequacy shortfall will occur . . . [or] that a reliability violation will occur," then the Illinois Power Agency, in conjunction with the IEPA, must develop a "Mitigation Plan" to reduce or delay CO_2e and co-pollutant emissions reduction requirements only to the extent and for the duration necessary to meet the State's resource adequacy and reliability needs. That Mitigation Plan must also consider the use of renewable energy, energy storage, demand response, transmission development, or other strategies to resolve the identified shortfall or violation.

This Mitigation Plan construct closely mirrors integrated resource planning (IRP) processes utilized by utilities and state commissions in many states, but which has not historically been authorized in Illinois. However, the Illinois General Assembly recently passed the Clean and Reliable Grid Affordability Act (CRGA) with an effective date of June 1, 2026. Under new Sections 16-201 and 16-202 of the Public Utilities Act introduced through CRGA, ICC Staff—working with the IPA, IEPA, Illinois Finance Authority, and retained consultants—must compile and propose a statewide Integrated Resource Plan addressing resource adequacy challenges over the first 5 years following approval and considering conditions over a 10-year horizon. This new language expressly requires the IRP to take into account the resource adequacy report prepared under Section 9.15(o) and address any divergences from its analysis or conclusions. Moreover, unlike the Mitigation Plan, an ICC-approved IRP may authorize changes or expansions to existing programs to effectuate investments in supply-, storage-, demand-side, or transmission alternatives.

For the Integrated Resource Plan established under CRGA, ICC Staff must submit the initial IRP to the Commission no later than November 15, 2026. While Section 9.15(o) provides no statutory timeline for initial publication of the Mitigation Plan, stakeholders will have 60 days to comment on a Draft Mitigation Plan after publication, and the IPA and IEPA will have 30 days thereafter to revise and file the Plan with the Commission for approval. Given the work inherent in properly weighing supply, demand-side, and transmission alternatives as required under Section 9.15(o) for Mitigation Plan development, the timeline and substantive work of IRP development and Mitigation Plan development is scheduled to substantially—if not entirely—overlap.

The Agencies recognize that parallel processes addressing similar subject matter and requiring similar evaluations before the same forum is ripe for synergies. As the IRP provides the broadest statutory authority to evaluate and effectuate investments in new supply, storage, transmission, demand-side alternatives, or emissions-requirement adjustments, it is the Agencies' preferred venue for comprehensive long-term planning. Nonetheless, Section 9.15(o) establishes certain mandatory procedural requirements, including at least one public workshop and stakeholder comment opportunity, which the IPA and IEPA will implement, being the agencies tasked with completing the Mitigation Plan. In addition to substantive discussion of the Resource Adequacy Study itself, these workshops will also provide a forum for stakeholder feedback on potential process alignment options, including whether to consolidate Commission proceedings, delay Mitigation Plan development until after IRP approval, or pursue statutory changes to harmonize the two processes. Given the overlap in responsible Agencies, any substantive feedback received during Mitigation Plan development workshops can also be merged into IRP development as well. Further details on the timing and process of Integrated Resource Plan development will be published in early 2026 by Commission Staff.

The Agencies look forward to working with a broad set of stakeholders in addressing reliability and resource adequacy challenges identified herein, and look forward to leveraging the new supply facilitation, demand management, and centralized planning tools authorized through CRGA to help meet such challenges in the years ahead.