

Generator Interconnection Interim Progress Report

Customer Reviews of the Seven U.S.
Regional Transmission System Operators

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*Prepared for Advanced Energy United
by Grid Strategies LLC and The Brattle Group*





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EXECUTIVE SUMMARY

Two years ago, we published the 2024 Advanced Energy United *Generator Interconnection Scorecard (2024 Scorecard)*; we provide this interim updated review of generator interconnection processes to provide a qualitative update on the progress and reform implementation underway (Progress Report). Currently, most of the seven regional transmission system operators (Regions) are in the process of implementing significant changes to their generator interconnection practices and policies in response to the large increase in interconnection requests over the past decade, the resulting queue backlogs, surging electricity demand, and the mandate of FERC Order No. 2023 (Order 2023). Because the full impact of these reforms is still uncertain, the Progress Report provides an initial evaluation of recent changes rather than new letter grades. This qualitative evaluation of progress is measured against the criteria, standards, and grades issued in the *2024 Scorecard*, which provided a baseline.

In a separate report also published in 2024, *Unlocking America's Energy*, we focused on priority reforms above and beyond Order 2023. Informed by those ideas, this Progress Report offers recommendations for each Region to build upon the progress to date to ensure an even faster, more predictable generator interconnection process.

Overall, we are seeing several themes across regions:

- ▶ Each Region has made meaningful progress in the last 18 months.
- ▶ Various gating policies, intended to foster a queue of projects that are ready to progress towards completion and operation, are beginning to shift more viable projects up in the queue and cause exit by less viable projects. It is not always clear, however, whether the “right” projects are exiting the queue in response to these gating policies or whether uncertainty and individual company risk tolerance are determining which projects continue in queues or drop out.
- ▶ Recent fast-track policies are straining open access principles and causing limited system headroom to be used by resources that are disproportionately utility-affiliated and more fossil-heavy relative to the average queue resources.
- ▶ New innovations in automation and entry-fee policies (as recommended by Advanced Energy United, Grid Strategies, and Brattle in *Unlocking America's Energy*) are being translated into reality through efforts such as SPP's Consolidated Planning Process (CPP), which has proven popular among stakeholders and FERC, and should be implemented quickly and effectively.
- ▶ Barriers outside of the Regions' control are becoming just as binding as interconnection processes—notably electrical equipment availability, network upgrade construction,

and local permitting¹—in delaying interconnection. While Regions cannot fix these, they can better enable developers to handle supply chain and siting challenges by removing uncertainty from the interconnection process.

- ▶ Grid capacity is a major constraint for interconnecting new resources in all Regions and is a challenge that cannot be addressed within the interconnection process alone. More proactive multi-purpose planning would alleviate these grid capacity constraints before resources submit interconnection requests.
- ▶ There are flexible interconnection services that could take advantage of storage’s inherent flexibility and ability to operate within a defined interconnection capacity limit; moreover, by harnessing storage’s ability to deploy faster than many other energy resources, Regions can help meet immediate energy and capacity needs at lower cost.
- ▶ Multiple regions are starting to deploy automation at various stages of the interconnection process and it is beginning to help. These efforts will succeed if the results are transparent and reproducible for interconnection customers, such that they avoid rather than increase uncertainty that complicates generators’ decisions about whether to post additional security, accept withdrawal-penalty exposure, or withdraw.

In addition to proactively planning transmission capacity and prioritizing the “most ready” interconnection requests, this Progress Report identifies five priority reforms that will be necessary for continued efficiency and expediency in interconnecting new resources to the grid. These include:

- ▶ Setting an entry fee for interconnecting new resources to pre-planned transmission capacity to reduce cost uncertainty for interconnection customers and increase overall efficiency of transmission buildout.
- ▶ Creating or updating processes for replacement of existing plants and making use of immediately available system capacity.
- ▶ Identifying the most cost-effective solutions for resolving reliability violations.
- ▶ Leveraging automation to expedite interconnection studies while providing enough transparency and replicability to provide confidence in results and support customer decisions.
- ▶ Improving reporting on transmission construction after the generator interconnection agreement has been signed.

Regional progress is summarized below in Table 1.

¹ For a discussion of the interaction between RTO interconnection speed and state siting authority see the Concurrence of Commissioner David Rosner, Order accepting Tariff Revisions by PJM, Docket ER26-1563, 195 FERC ¶ 61,197 (June 9, 2026).

TABLE 1 | Progress Report Evaluation

Region	Progress	Key Drivers and What to Watch
SPP	<p>Promising Improvements</p> <p>Previous Grade</p> <p>C-</p>	<p>SPP has made substantial progress in working through its queue backlog due to a more efficient process and the help of automation tools, studying 340 GW in the past two years. SPP’s 2024 cluster study is underway but did not initiate a 2025 cluster study. SPP is taking the lead on integrating its interconnection processes with an efficient regional transmission expansion through its soon-to-be-tested Consolidated Planning Process (CPP) and interregional coordination with MISO through the Joint Targeted Interconnection Queue Study (JTIQ). CPP integrates SPP’s interconnection and regional transmission planning processes, enabling interconnection customers to request interconnection service for a predictable per-MW fee, known as GRID-C, that reflects the regional costs of interconnection and any remaining network upgrades at the specific location requested. The identification of regional and zonal network upgrades through efficient regional planning is anticipated to enable interconnection customers to trade higher (but less uncertain) upfront costs for reduced interconnection study and network upgrade construction delays. This structure encourages new projects to utilize available capacity. SPP has not yet announced GRID-C, raising concerns that the rate will be cost prohibitive, which would negatively affect the number and total quantity of projects in the queue. SPP also implemented a one-time Expedited Resource Adequacy Study (ERAS) fast-track cluster that has predominantly benefited thermal resources and remains under appellate review. Finally, SPP has been proactive in developing market rules to interconnect large loads co-located or proximally located with generation, known as the HILL and HILLGA processes, and the related conditional interconnection process known as CHILLS.</p> <p>What to Watch: CPP implementation, including how much transmission capacity is available at the Planned Interconnection Locations and whether the forthcoming GRID-C is attractive. SPP is expected to post the first GRID-C in Fall 2026. The amount of resources that enter through the ERAS and HILLGA processes will also be a focus over the next year. In addition, the MISO-SPP Coordinated System Plan is worth watching.</p> <p>Priority reforms: Implement CPP at a reasonable cost for interconnection customers. Increase utilization of alternative solutions (such as Remedial Action Schemes (RAS) and Grid Enhancing Technologies (GETs)) to reduce needed network upgrades; identify cost-effective solutions with power flow modeling.</p>

Region	Progress	Key Drivers and What to Watch
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MISO	<p>Incomplete Progress</p> <p>Previous Grade</p> <p>C-</p>	<p>MISO continues to work through a large backlog of interconnection requests. Since the <i>2024 Scorecard</i>, MISO completed the 2019 and 2020 cluster studies, but recently notified stakeholders of additional delays for all active clusters including the 2021, 2022, and 2023 clusters. Similar to SPP, MISO skipped a cluster study in 2024 and is now implementing a suite of reforms beginning with the 2025 cluster to manage queue volume, including a zonal queue cap of 50% of load, increased readiness requirements beyond those required by Order 2023, and transparency on the capacity and location of current queue requests. In addition to working through the current queue, MISO is focused on achieving a one-year study timeline with the help of automation and improved project management software. However, study delays and restudies continue to be a problem despite MISO’s use of automation in Phase 1 of its study process. To address power flow modeling delays, MISO has implemented several rule changes to standardize input data from interconnection customers. MISO has continued to pursue significant regional transmission expansion, approving over \$30 billion of 345 kV and 765 kV backbone projects through Long Range Transmission Planning (LRTP) Tranche 2.1 and in coordination with SPP through JTIQ, both of which will reduce the scale of network upgrades in current Definitive Planning Phase (DPP) studies. Lastly, MISO implemented a parallel ERAS serial fast lane that has been challenging for non-ERAS interconnection customers, given that most ERAS projects are thermal resources and both ERAS and DPP projects are allocated the same transmission capacity in parallel studies. MISO will perform quarterly ERAS studies through mid-2027. MISO has also proposed a Zero Injection Generation Interconnection Agreement (ZGIA) process to allow generation serving load at the same interconnection point to obtain a GIA in months, with limited studies and cost, if there is no injection into the transmission system.</p> <p>What to Watch: How quickly MISO is able to make progress on its significant backlog, how the zonal cap and readiness requirements—as well as improved internal queue management—improve the DPP-2025 and future clusters; the ZGIA process; whether LRTP upgrades unlock headroom for customers in the standard queue; and whether ERAS supports “shovel ready” projects or not.</p> <p>Priority Reforms: Address ongoing issues that delay the cluster study process through increasing use of automation, new process management tools, and alternative solutions (such as RAS and GETs) to achieve a one-year study timeline. Prioritize resources to study up to the zonal cap based on a “most ready” framework. Provide greater simplicity and cost certainty, similar to SPP’s CPP approach. Improve model accuracy and transparency.</p>
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Region **Progress** **Key Drivers and What to Watch**

PJM **Expected Progress**

Previous Grade
D-

PJM is reaching the end of its lengthy queue and study transition process and has met its planned timeline through increased staffing and the use of new software and project management automation. As part of these efforts, PJM is implementing additional reforms to its surplus interconnection service and capacity interconnection rights transfer process (tools that have not been widely utilized since they were introduced a year ago) and has dedicated resources to tracking the post-GIA phase, including transmission owner construction schedules. However, PJM’s lengthy transition relied on less optimal stopgap measures, including the Reliability Resource Initiative (RRI) and the new Expedited Interconnection Track (EIT). While intended to meet emergency reliability needs, high network upgrade costs assigned to RRI projects suggest that there is a lack of headroom for new resources, resulting from insufficient proactive transmission planning. Very recent reports suggest that regional network transmission planning has significantly reduced interconnection costs.

What to Watch: The 220 GW that have applied to connect through the first cycle of PJM’s reformed interconnection process will be a challenge. The four-year process to get to this point has contributed to generation supply shortfalls, making timely processing of the current cluster even more critical. Additional open questions include how the recently approved EIT impacts the Cycle process.

Priority Reforms: Implement proactive transmission planning that identifies cost-effective network upgrades in anticipation of new resource and load additions. Increase simplicity and cost certainty similar to SPP’s CPP approach. Model cost-effective alternative transmission technologies.



Region	Progress	Key Drivers and What to Watch
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CAISO	<p>Promising Improvements</p> <p>Previous Grade B</p>	<p>CAISO has completed all previous clusters through Cluster 14 (24 GW of resources with executed or in-progress IA) and is currently completing Cluster 15, which was initially opened in 2023 and then re-opened in 2025. CAISO is addressing study delays through Interconnection Process Enhancements (IPE) reforms that use cluster studies with zonal caps and score requests based on where the system has available capacity, commercial readiness, and demand by CAISO load serving entities, amongst other key factors. CAISO’s new scoring criteria, while the subject of criticism from customers because of the potential for load-serving entities to discriminate against IPPs, generally have worked as intended and discrimination concerns did materialize when Cluster 15 re-opened. Scoring and zonal caps at 150% of available capacity allowed CAISO to focus studies on the most-ready projects while supporting competition. CAISO further supports site selection by providing significant information prior to interconnection application submission (heat map, POI constraint mapping) for identifying less congested portions of the system. About one-third of capacity sought energy-only interconnection, demonstrating interest in CAISO’s alternative interconnection options. CAISO regularly utilizes RAS to support interconnection but is starting to hit limits on the level of complexity they introduce. Information provided to interconnection customers is enabled in part by CAISO’s continued proactive approval of transmission upgrades to meet the state’s reliability and future resource needs. Similar to SPP, the interconnection process is well coordinated with the annual planning process to ensure regional, backbone projects are built in anticipation of new resource additions and the available capacity is utilized for setting zonal limits in the interconnection process. With significant transmission development and new resource additions, waiting times from GIA to commercial operation date (COD) remain particularly high, largely due to permitting, procurement, and transmission completion.</p> <p>What to Watch: Cluster 16 will test whether the IPE reforms will effectively reduce total submitted requests, direct entry towards portions of the system with available capacity, and reduce study timelines.</p> <p>Priority Reforms: Improve reporting on transmission project construction progress and approaches for incentivizing faster completion of projects.</p>
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ISO-NE	<p>Expected Progress</p> <p>Previous Grade D+</p>	<p>ISO-NE has not received a similar volume of requests as other regions and is up to date on interconnection studies; 10 GW of projects remain active, most of which have executed an interconnection agreement. ISO-NE adopted a cluster study process in its Order 2023 compliance filing and initiated its transition cluster, which includes 4.8 GW of resources, with expected completion later in 2026. The first regular cluster study is scheduled to begin in late 2026. ISO-NE, in collaboration with the New England states, finalized its Longer-Term Transmission Planning (LTTP) process to identify regional, multi-value upgrades and solicit competitive proposals. The first LTTP process, focused on upgrades to the critical corridor between Maine and southern New England that will create headroom and ultimately reduce prohibitive network upgrade costs for resources sited in Maine, is underway.</p> <p>What to Watch: Whether ISO-NE can complete its transitional cluster on time and whether the fully implemented updates result in a more efficient process.</p> <p>Priority Reforms: Implement reforms to surplus interconnection rules. Increase simplicity and cost certainty similar to SPP’s CPP approach. Implement automation tools.</p>
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Region	Progress	Key Drivers and What to Watch
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NYISO	<p>Expected Progress</p> <p>Previous Grade C-</p>	<p>NYISO’s transition cluster study, the first under its Order 2023-compliant rules, is underway and has been subject to minor delays due to a large cluster size, application deficiencies, and challenges in defining the base case. In complying with Order 2023, NYISO largely retained the design of its interconnection process, now retitled the “Cluster Study,” and incorporated Order 2023 reforms, such as more stringent readiness requirements and elimination of the “reasonable efforts” standard. In addition, NYISO is working on a range of reforms to improve future clusters: providing applicants more information on system availability through a “feasibility screen,” improving its application process and interconnection portal; and updating the deliverability test methodology to increase the accuracy of network upgrade identification.</p> <p>What to Watch: Whether planned reforms have a positive impact on the next cluster, anticipated to start in August 2026, including helping manage a potentially large number of requests.</p> <p>Priority Reforms: Drive toward certainty of cost and timing; increase utilization of alternative solutions to reduce network upgrade needs; be more transparent about post-GIA progress; and seek to automate elements of the interconnection process.</p>
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ERCOT	<p>Incremental Progress</p> <p>Previous Grade B</p>	<p>ERCOT’s unique approach continues to get high marks for processing a high volume of interconnection requests that sign GIA on a reasonable timeline and at reasonable costs. As of April 30, 2026, there were 1,965 active generation interconnection requests representing 453 GW, with no current interconnection study backlog. ERCOT has recently approved over \$30 billion in 765 kV lines that, while intended to help serve large loads, are expected to improve headroom for generator interconnection customers in West Texas, which has long been plagued by significant transmission constraints. Notably, effective January 1, 2026, ERCOT adopted a policy that assigns cost responsibility above a standard allowance to interconnection customers, instead of requiring these costs to be covered entirely by transmission providers and ultimately load. The standard allowance of \$20 million for interconnections at voltages greater than 138 kV is intended to cover typical ERCOT interconnection costs so impacts to customers should be relatively small. ERCOT is also experiencing an unprecedented influx of large load interconnection requests, which, given overlapping modeling and staff workload requirements, may slow generator interconnection timelines.</p> <p>What to Watch: How the new standard allowance policies play out in practice and how the growth in large load interconnection requests affects the generator interconnection process.</p> <p>Priority Reforms: Implement proactive transmission planning to reduce congestion and curtailment risk after generators are connected.</p>
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INTRODUCTION

The Purpose of The Generator Interconnection Progress Report

The 2024 Advanced Energy United *Generator Interconnection Scorecard* evaluated seven regional transmission system operators (generally referred to as “Regions”) on their generator interconnection processes and assigned each one a grade.² All of the Regions, including Southwest Power Pool (SPP), Midcontinent Independent System Operator (MISO), PJM Interconnection (PJM), California Independent System Operator (CAISO), Independent System Operator of New England (ISO-NE), New York Independent System Operator (NYISO), and Electric Reliability Council of Texas (ERCOT), are in the process of implementing significant changes to their interconnection practices and policies in response to the large increase in interconnection requests over the past decade and the resulting queue backlogs; surging electricity demand; and FERC Order 2023 (Order 2023), which applies to all Regions except ERCOT. Recognizing that the full impact of these reforms is still uncertain, this Progress Report provides an interim update rather than new letter grades. This qualitative evaluation of progress is measured against the criteria, standards, and grades issued in the *2024 Scorecard*, which provided a baseline. Future generator interconnection reports may include issuance of new grades once the impact of ongoing reforms can be more fully assessed.

This Progress Report identifies key trends across the Regions and then provides a summary of each Region’s progress clearing their interconnection queue backlog, their compliance with Order 2023, and additional reforms underway to improve their interconnection processes. Finally, this Progress Report identifies additional priority reforms that will be necessary for continued progress in efficiently interconnecting new resources to the grid. The August 2024 *Unlocking America’s Energy* report detailed a package of reforms, targeting different aspects of the interconnection process.³ In light of the progress made to date in each Region, we have identified the five priority reforms from that package that will both address ongoing issues and complement existing reform efforts.

To develop this Progress Report, the project team reviewed publicly available information on the successes of and challenges facing the generator interconnection processes across the country. This included Lawrence Berkeley National Laboratory’s (LBNL’s) *Queued Up 2025 Edition: Characteristics of Power Plants Seeking Transmission Interconnection As of the End of 2024* and related data.⁴ The project team also met with interconnection staff at the Regions to capture a comprehensive picture of progress to date. The views and recommendations expressed in this Progress Report are solely those of the authors and do not necessarily reflect the positions and endorsement of Region staff. In addition, the Progress Report relies upon other published works, as cited, and the project team’s professional experience.

² Grid Strategies LLC and The Brattle Group, *Generator Interconnection Scorecard: Ranking Interconnection Outcomes and Processes of the Seven U.S. Regional Transmission System Operators* (Feb. 2024) (*2024 Scorecard*).

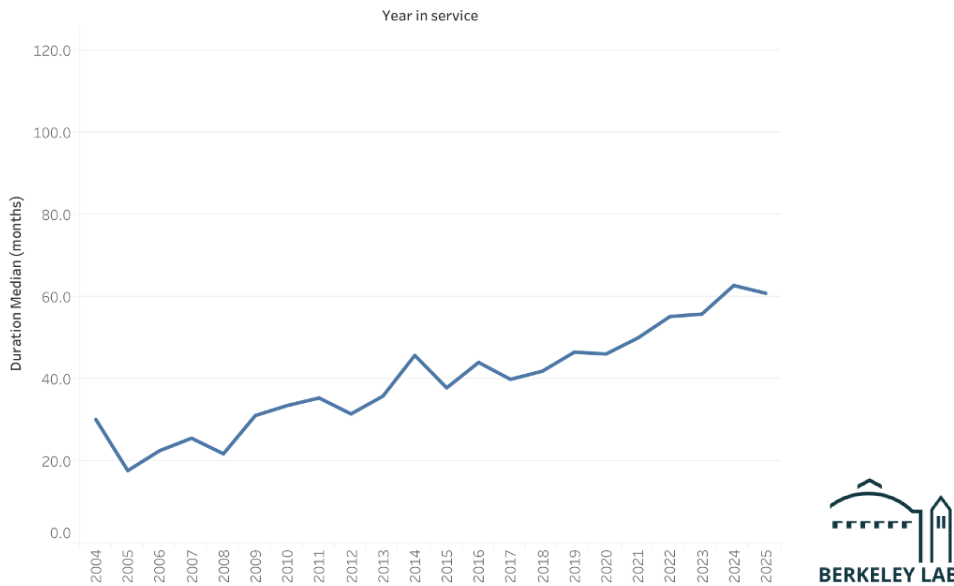
³ Grid Strategies LLC and The Brattle Group, *Unlocking America’s Energy: How to Efficiently Connect New Generation to the Grid* (Aug. 2024) (*Unlocking America’s Energy*).

⁴ LBNL, *Queued Up: 2025 Edition, Characteristics of Power Plants Seeking Transmission Interconnection As of the End of 2024* (Dec. 2025) (*Queued Up 2025*).

KEY TRENDS

- ▶ The Regions have made significant progress in processing interconnection backlogs while improving the process for future study cycles that are currently or soon-to-be underway.
- ▶ Across the board, Regions are placing substantial focus on and efforts into improving the management of the interconnection process including hiring additional staff, upgrading project management tools, applying automation, increasing transparency, and improving coordination with transmission owners and interconnection customers.
- ▶ There is not yet strong evidence that interconnection speed has improved.

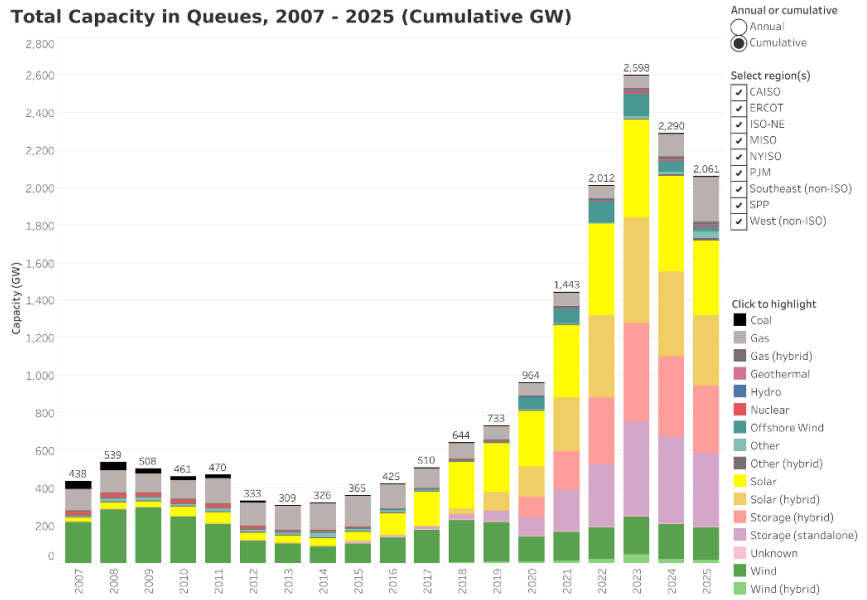
FIGURE 1 | Duration of interconnection only starting to reduce⁵



- ▶ The combined impact of Order No. 2023 and Region-specific reforms are improving outcomes for interconnection customers, but not all pressing interconnection issues have been addressed.
- ▶ Ongoing reforms and posted cluster application windows resulted in few (or no) *new* requests being accepted for study in CAISO, SPP, MISO, and PJM in 2024 (outside of separate fast-track processes). Some regions (e.g., PJM) experienced even longer pauses in new interconnection requests.
- ▶ Higher withdrawal rates were seen in 2024 (and continued into 2025) due to reforms, delays, and exogenous factors as the Regions increased their throughput of studies, but the active capacity in queues remains high.

⁵ See *id.*, Transmission Interconnection Queue Durations and Outcomes.

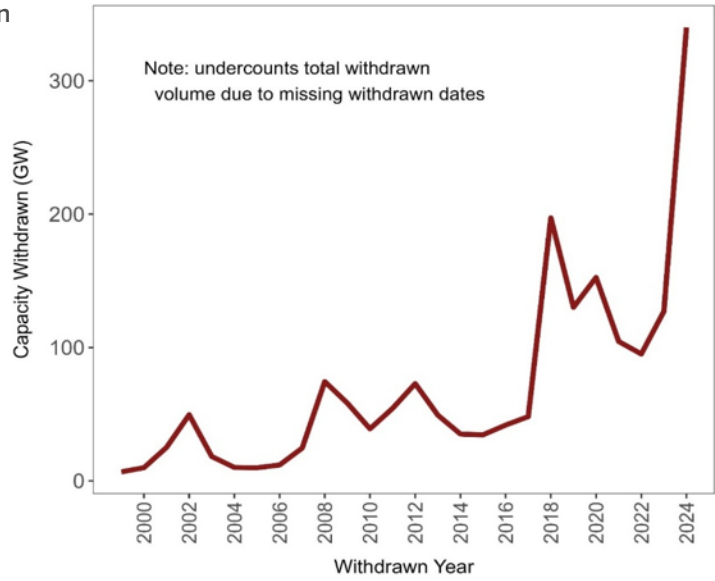
FIGURE 2 Total Capacity in Queues has Fallen Slightly⁶



Notes:
 • Hybrid storage capacity is estimated for some projects.
 • Data for battery storage and all hybrid categories are from 2018 through 2025. Batteries are reported in MW, not MWh, because developers request interconnection capacity in MW.
 • Reforms in some ISOs during recent years have paused interconnection requests during those years.
 • ERCOT queue data includes only projects that have requested a full interconnection study (FIS). ..

Withdrawal rates are increasing as shown below. Withdrawals can result in a more manageable queue, but it is important to have a structure where the most viable and efficient projects are the ones that move forward, and the projects that leave are not exiting because of an unpredictable process.

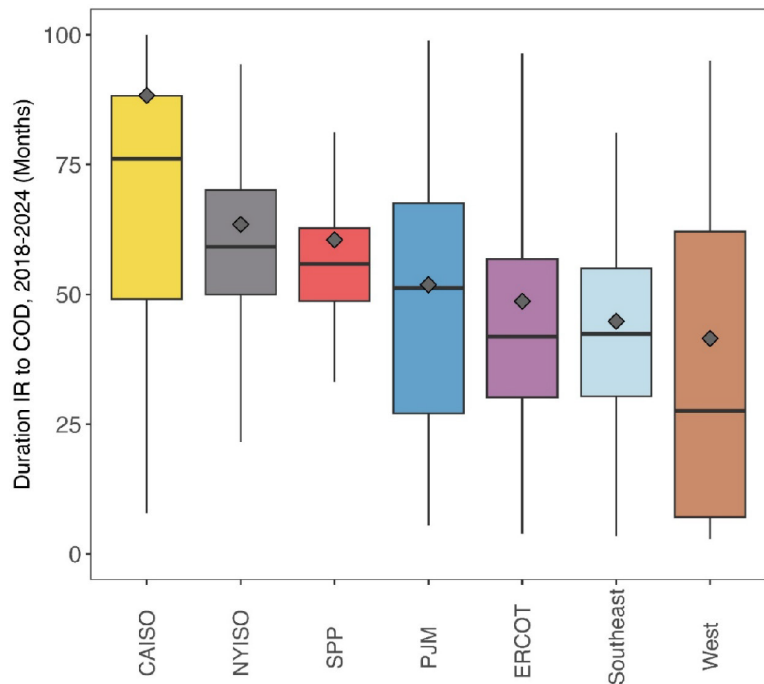
FIGURE 3 Annual Capacity Withdrawn from Interconnection Queues, 1999-2024⁷



6 Queued Up 2025, Generation Storage and Hybrid Capacity in Interconnection Queues.
 7 See id. at 4.

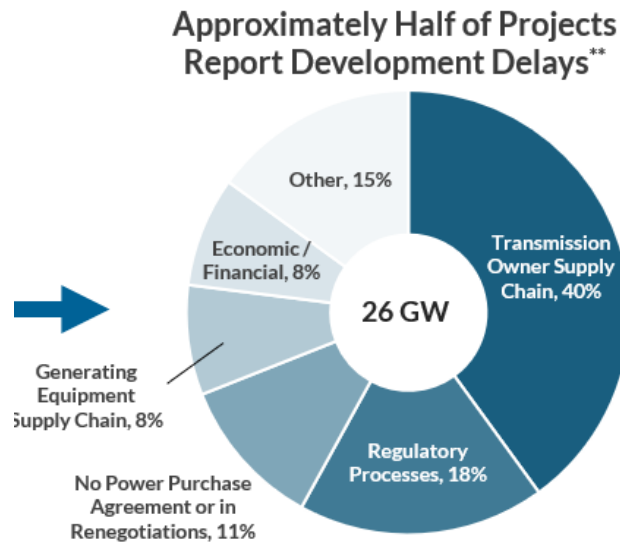
- ▶ Fast track proposals are causing tension and raise concerns about discrimination between different kinds of projects: those already in the queue vs new projects; utility-owned vs independent power producers; and fossil vs other generation.
- ▶ Of the reforms that go above and beyond Order 2023, SPP’s CPP and GRID-C approach is the most holistic and innovative, with potential to reduce uncertainty, speed interconnection timelines, and lead to better outcomes for both interconnection customers and load. Other Regions have taken steps to make queue volumes more manageable. Early indications are that these measures, including CAISO’s scoring approach and MISO’s zonal caps, will (to varying degrees reflecting the very different nature of these reforms) improve the Regions’ ability to process interconnection requests, but more time is needed to implement and assess them.
- ▶ The post-GIA phase remains an area for improvement across the Regions; while the Regions have some control over progress during this period, projects face delays due to procurement, permitting, and transmission construction.

FIGURE 4 | Duration from Initial Request to Commercial Operation Date, 2018-2024 (Months)⁸



8 Queued Up 2025 at 48.

Delays are caused by a number of factors. MISO, for example, has broken down the delays this way:⁹



Order 2023 Compliance

On July 28, 2023, FERC issued Order 2023, designed to enhance the processes and agreements used by electric transmission providers to interconnect new generating facilities into the existing transmission system.¹⁰ Through these reforms, FERC sought to address the significant delays and backlogs for generators¹¹ seeking to interconnect to the bulk transmission system. Key elements of Order 2023 include:

- ▶ Transition to a “first-ready, first-served” cluster study process, where interconnection requests are grouped and studied together.
- ▶ Mandated cluster study timelines.
- ▶ Stricter financial readiness, increased milestone deposits, and more demanding site control requirements for interconnecting generators.
- ▶ Required use of established methodologies for allocating cluster study costs and network upgrade costs among interconnection customers.
- ▶ Deadlines and penalties for transmission providers that fail to complete interconnection studies on time, replacing the previous requirement for transmission providers to make “reasonable efforts” to meet study deadlines.
- ▶ Publicly available heatmaps that display available transmission capacity.

⁹ MISO, [2024 Regional Resource Assessment](#) at 24 (Jan. 2025).

¹⁰ FERC, [Order No. 2023, Improvements to Generator Interconnection Procedures and Agreements](#), 184 FERC ¶ 61,054 (July 28, 2023) (Order 2023).

¹¹ Note that throughout this Progress Report, generation is understood to encompass all technologies that deliver power to the grid, including storage technologies that also draw power from the grid.

- ▶ A detailed process for studying the impacts of proposed generating facilities on neighboring transmission systems.
- ▶ Mandated consideration of technical advancements, including resource co-location on a shared site and evaluation of alternative transmission technologies in cluster studies.
- ▶ Modified timing requirements for surplus interconnection service, allowing surplus requests as soon as the original interconnection customer reaches GIA, rather than waiting for commercial operation.

The FERC-jurisdictional Regions submitted compliance filings in May 2024.¹² With the exception of ISO-NE, all of the FERC-jurisdictional Regions transitioned to a cluster study process before Order 2023 became effective and many have continued to implement regionally-tailored reforms to their cluster study processes that go beyond the final rule's requirements.

¹² ERCOT is not a FERC-jurisdictional entity, but is evaluated in this Progress Report similar to the other Regions.



FIVE PRIORITY REFORMS FOR ALL REGIONS

Order 2023 and Region-specific reforms have improved interconnection processes nationwide, but additional reforms are still needed to ensure access to new, cost-effective generation and storage in a timely manner. The August 2024 *Unlocking America's Energy* report identified a package of reforms, targeting different aspects of the interconnection process. In light of the progress made to date in each region, we have identified the five priority reforms from that package that will address ongoing issues as well as complement existing reform efforts. This section describes each priority reform generally and identifies regions that should pursue implementation. In the following section, after a discussion of the status of ongoing reforms, we identify Region-specific considerations for pursuing applicable reforms.

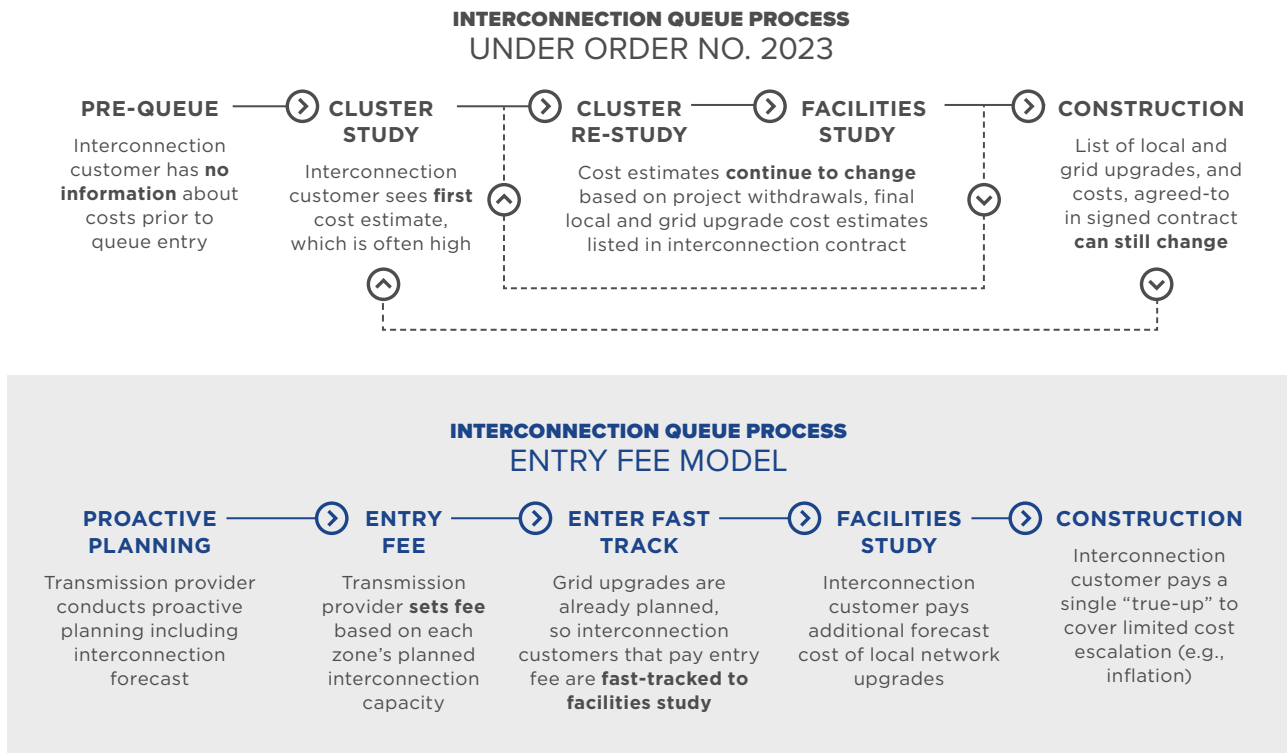
Utilize an Entry Fee for Proactively Planned Transmission Capacity Expansion and Prioritize “Most Ready” Requests

In most Regions, network upgrade costs are determined only after an interconnection customer enters into a cluster for study, and these costs can shift materially throughout the study process, including when withdrawals trigger restudies. Because cost exposure is unknown at the time of application, the queue becomes the mechanism through which developers discover where projects may be financially viable. This dynamic contributes to excessive queue volume, repeated restudies, and unstable cost outcomes. The expanded readiness requirements and increased milestone deposits implemented by Regions either ahead of or in compliance with FERC Order No. 2023 will help reduce, but not resolve, this cycle of restudies and delays propelled by uncertainty.

This reform calls for adoption of an interconnection entry fee tied to proactively planned transmission capacity expansion to provide cost certainty to interconnection customers. Under this framework, transmission providers identify zones where additional headroom will be created and establish an entry fee that covers some of the facilities, which imposes more discipline on developers to propose viable projects. New projects electing to interconnect in those zones pay the upfront fee and proceed through a streamlined interconnection process, subject to readiness and withdrawal requirements, and later pay for local network upgrades. The model shifts most cost determination from the study phase to the planning phase and aligns financial commitment with identified transmission expansion.

FIGURE 5 | Entry Fee For Planned Transmission Capacity Expansion¹³

ENTRY FEE APPROACH



Implementation requires integration between transmission planning and interconnection procedures. Regions pursuing this approach typically identify planned interconnection locations in the initial planning phase, limit the volume of capacity available in a given cycle, and apply prioritization tools when demand exceeds available headroom.

SPP's CPP framework, MISO-SPP JTIQ, and CAISO's zonal scoring structure are examples of this reform in practice. The CPP cost allocation framework will provide more cost certainty than JTIQ because interconnection customers will share the costs of the proactively planned transmission capacity with load. In contrast, under JTIQ, interconnection customers fully fund the upgrades and therefore must pay a true-up adjustment once upgrades are in service and final costs are known. This true-up approach undermines the cost certainty of the entry fee framework because interconnection customers are expected to enter into binding commitments, but the transmission owners are not obligated to control costs or avoid late discovery of project requirements that increase costs.¹⁴ In CAISO, interconnection customers seeking to interconnect in a deliverable zone are eligible for reimbursement of network upgrade costs, which resolves cost certainty issues for interconnection customers.

¹³ *Unlocking America's Energy* at 8.

¹⁴ *Id.* at 31.

Priority Regions for Entry Fee: This reform is particularly relevant for MISO and PJM, where cost uncertainty for interconnection customers remains an acute problem, but is relevant to all Regions where network upgrade costs are determined only after entry into a cluster study.¹⁵ If SPP's CPP is implemented well, it can serve as a model for other Regions.

Create or Update Processes for Replacement of Existing Plants and Make Use of Immediately Available System Capability

Even before long-term planning can identify regional facilities to enable additional system headroom, the most attractive points of interconnection (POI)—those with immediately available capability—in many cases are locations where generators are retiring or operating below full output. This reform calls for generator replacement procedures and enhanced surplus interconnection service so that new resources can more quickly access vacated interconnection rights where system impacts are minimal.

Headroom at an existing POI can be made available for sharing with new resources if the existing generating resource rarely utilizes the full system capacity associated with its interconnection service agreement. Surplus service is the use of existing capacity for new generators that does not trigger any upgrades or adverse impacts. The implementation of FERC-mandated surplus service varies widely across Regions and Order 2023 did not materially change the scope of surplus service. MISO's surplus framework, which includes a presumption of no material impact where total energy and capacity limits at the existing POI are not exceeded, has seen measurable uptake. SPP has adopted a similar approach and seen similar uptake of the surplus product. PJM removed key limitations around the use of surplus interconnection service, but additional reforms may be needed to enable meaningful uptake. CAISO and ISO-NE impose eligibility restrictions, technology limitations, or modeling assumptions that constrain practical use, while NYISO does not offer surplus service. As a result, surplus processes function unevenly across the Regions.

MISO, SPP, and PJM have implemented generation replacement processes that allow new resources to interconnect at the same substation as a retiring resource, avoiding the full standard queue process. In accepting generation replacement processes, FERC has cited that they avoid duplicative study and operational costs that otherwise would result when the request to replace an existing generating facility proceeds through the standard queue. If the replacement request will cause an adverse impact on the transmission system, however, it must instead be processed through the standard queue.

Priority Regions for Replacement and Existing Capacity: ISO-NE has already initiated consideration of reforms to surplus service at the request of stakeholders, and we recommend that CAISO and NYISO consider whether similar reforms are needed to ensure that surplus processes serve as a practical option for interconnecting resources. This includes considering whether surplus resources should be able to access NRIS for the surplus transmission capacity and serve as a capacity resource, a reform that might also be relevant to PJM. We further

¹⁵ For example, RWE Clean Energy, LLC submitted a complaint to FERC following PJM allocation of a \$71.6 million network upgrade in Transition Cycle #1 Phase III. In denying the complaint, FERC encouraged PJM to consider whether there are regionally appropriate reforms that could reduce interconnection cost uncertainty and expedite the interconnection process in PJM. FERC, Order Denying Complaint, 194 FERC ¶ 61,212 at P 44 (Mar. 19, 2026).

recommend that CAISO, NYISO, ERCOT, and ISO-NE consider adopting generation replacement procedures.

Identify the Most Cost-Effective Solutions for Resolving Reliability Violations

When cluster studies identify reliability violations, the upgrade selected to resolve those violations determines project cost and timeline outcomes. Traditional, capital-intensive upgrades are frequently identified even where alternative solutions may address the same constraint at lower cost or on a shorter timeline.

This reform calls for transmission providers to evaluate the full range of commercially available solutions when resolving identified constraints. These include grid-enhancing technologies, storage as transmission, remedial action schemes, and advanced conductor upgrades. In particular, remedial action schemes (RAS)—defined by NERC as an automatic protection system designed to detect predetermined system conditions and take corrective action to maintain system reliability—have been deployed extensively in the West. CAISO reported that its use of RAS has created approximately 21,000 MW of additional interconnection headroom. Adoption of comparable approaches has been more limited in other Regions. For example, ISO-NE, through a long-standing official “planning procedure,” sharply limits use of RAS in the interconnection process.¹⁶ Eastern RTOs should consider expanded use of RAS to facilitate interconnection of projects when studies show they trigger potential reliability violations.

Order 2023 requires transmission providers to evaluate alternative transmission technologies (ATT) during cluster studies. Presently, it is too easy for Order 2023’s “consider ATT” requirement to be treated as a check-the-box exercise where no real evaluation actually takes place, and Regions are sometimes unable to influence the transmission owners who determine what technologies are deployed on the transmission system which they own. Each Region should run power flow modeling with a tool that is capable of identifying and optimizing ATTs and publicly report the results.

Priority Regions for Cost-Effective Solutions for Resolving Reliability Violations: SPP, MISO, PJM, NYISO, ISO-NE. As noted, CAISO uses RAS effectively. In Texas, the connect and manage approach addresses reliability concerns related to interconnection.

Leverage Automation to Expedite Interconnection Studies

Several Regions have adopted automation tools for intake management, base case construction, and workflow coordination. We recommend continued and expanded use of automation tools to accelerate time-intensive processes in tandem with other reforms. In regions such as SPP and MISO, use of automated modeling platforms has reduced base case development timelines materially. In MISO, automation also has improved initial study timelines. However, to address interconnection customer concerns, Regions need to provide more transparency about the use of these automation tools and facilitate replicability of their results by customers. Automation has also improved internal tracking of study milestones and sped up other tasks, such as legal

¹⁶ ISO-NE, [Planning Procedure No. 5-5: Requirements and Guidelines for Application of Remedial Action Schemes and Automatic Control Schemes](#) (Jan. 7, 2021).

document creation and cost allocation calculations in PJM. PJM's automation efforts promise to accelerate the interconnection application review process, another time-consuming step.

Automation alone, however, does not address the underlying drivers of restudies, including high withdrawal rates and limited transmission headroom. Regions that combine automation with readiness reforms or planning-based capacity expansion appear better positioned to stabilize study timelines. Of note, once Regions resolve their backlogs, automation will be an important tool for staying on track and meeting required study deadlines. Over time, cluster cycles that begin and end on schedule will avoid base case modeling issues that arise when multiple clusters are underway at once.

Priority Regions for Automation: Most Regions have introduced at least some automation into their process, particularly for the time-consuming application and customer management components. Regions that have already begun the process of introducing automation and AI into the study process should continue along this path but must ensure transparency and allow for iteration and improvement to avoid harm to interconnection customers as these tools evolve.

Improve Reporting on the Post-GIA Transmission Construction Phase

Execution of a generator interconnection agreement (GIA) concludes the study phase but is not the last hurdle to reaching commercial operation. Required network upgrades must still be engineered, supplied with electrical equipment that is hard to source and procure, and actually constructed before projects commence commercial operation. In many Regions, delays during this phase contribute materially to total project timelines. There are many factors that may contribute to such delays. Among them are supply chain bottlenecks, permitting issues, prioritization/project management by transmission owners, and voluntary delays by interconnection customers who may lack contracts with power customers, necessary permits, or face construction delays of their own. Along the way, costs assigned to interconnection customers can increase without warning and without any options for recourse, inserting additional uncertainty even after the customer has committed to move forward.

There is an analytical gap about this phase because of the absence of standardized reporting that would help distinguish transmission-owner-attributable delays from delays driven by external factors such as permitting constraints or supply chain conditions. Without consistent data linking network upgrade schedules to generator commercial operation dates and categorizing delay causes, it is difficult to assess construction phase performance across transmission owners—and therefore impossible to develop appropriately targeted solutions to expedite commercial operations.

We recommend more consistent reporting of construction milestones, cost revisions, and delay drivers. Improved reporting would allow comparison across transmission owners and provide a clearer basis for evaluating whether construction timelines are aligned with expectations. PJM and CAISO have dedicated resources to tracking and reporting. PJM tracks the causes of changes in construction milestones in the post-GIA phase and reports these quarterly to its Interconnection Process Subcommittee. CAISO holds transmission development forums twice

per year to provide status updates for transmission projects previously approved through the planning process and network upgrades identified in the generation interconnection process.

It is important to note that siting and permitting processes are a source of delay and project cancellation, but occur outside of the generator interconnection process and are beyond the purview of the Regions. Siting and permitting processes are complex and may require approval from federal, Tribal, state, and local governments. Local ordinances and zoning laws are particularly problematic for new generation. Between 2018 and 2023, at least 30 percent of utility-scale wind and solar projects were cancelled during the siting process, largely because of community opposition, local ordinances, and zoning.¹⁷ Regions can work with their states to recommend improved siting practices. Data collected about post-GIA delays will help to inform these recommendations.

Priority Regions for Post-GIA Reporting: All regions could improve the transparency and tracking of post-GIA activities and costs. Regions like PJM that already do some level of tracking could increase the granularity and scope of this information (e.g., tracking by transmission owner, identifying more specific causes of delays rather than high-level categories, including cost data—which MISO presents in an online dashboard), and work to create venues, such as CAISO’s transmission development forum, to discuss the status of network upgrades with interconnection customers, transmission owners, states, and other stakeholders.

¹⁷ See, e.g., Sabin Center for Climate Change Law, Columbia Law School, Opposition to Renewable Energy Facilities in the United States: June 2025 Edition at 10 (July 2025).

REGIONAL EVALUATIONS

We summarize for each Region their progress in clearing their interconnection queue backlog, their compliance with Order 2023, and additional reforms underway to improve their interconnection processes.

SPP

Promising improvements. SPP has made substantial progress in working through its queue backlog due to a more efficient process and the help of automation tools, studying 340 GW in the past two years. SPP's 2024 cluster study started in December 2024 and is currently scheduled to reach the GIA phase in May 2027, an 18-month cycle. SPP did not initiate a 2025 cluster study.

SPP is taking the lead on integrating its interconnection processes with efficient regional transmission expansion through its Consolidated Planning Process (CPP) and interregional coordination with MISO through the Joint Targeted Interconnection Queue Study (JTIQ). CPP integrates SPP's interconnection and regional transmission planning processes, enabling interconnection customers to request interconnection service for a predictable per-MW fee, known as the Generalized Rate for Interconnection Development - Contribution (GRID-C) rate, that reflects the regional costs of supporting interconnection and any remaining network upgrades at the specific location requested. The identification of regional and zonal network upgrades through efficient regional planning is anticipated to allow interconnection customers to trade higher (but more certain) upfront costs for reduced interconnection study and network upgrade construction delays. This structure increases commitment from interconnection customers for utilizing available capacity.

Given that SPP has not yet announced GRID-C, the question of whether the rate will be cost prohibitive for interconnection customers remains outstanding. It also remains unclear the degree to which this new rate option will impact the number of interconnection requests.

In addition to the CPP, SPP also implemented a one-time Expedited Resource Adequacy Study (ERAS) fast-track cluster. Accelerating only select projects raises concerns among other interconnection customers about discrimination against projects in the existing queue, between utility-owned and independent projects, and between fossil and other supply sources. Thermal resources account for 65% of ERAS requests. The policy remains under appellate review.

Finally, SPP has been proactive in developing market rules for the interconnection of large loads co-located with generation, known as their High Impact Large Load (HILL) and HILL Generation Assessment (HILLGA) processes.

The *2024 Scorecard* awarded SPP a "C-" citing the availability of interconnection alternatives and SPP's coordination with MISO on transmission planning as positives, while noting that

frequent restudies and errors made the results of the interconnection process undependable for new projects.

Queue Status

SPP's three-phase interconnection study cluster process, known as the Definitive Interconnection System Impact Study (DISIS), consists of a system impact study, divided into two phases (Phase 1 and Phase 2), followed by an interconnection facilities study. SPP is currently in the re-study study phase for the 2022 and 2023 clusters and has completed Phase 1 for the 2024 cluster. In mid-2024, SPP reached a point where the ongoing number of restudies and the volume of queued interconnection requests created significant uncertainty for the assumptions underlying any new Phase 1 studies. At the time, SPP was conducting Phase 2 restudies for the 2018 through 2023 clusters. Because of delayed restudies for earlier clusters, SPP temporarily paused review of new interconnection applications, delaying the end of the DISIS-2024 application window to March 1, 2025.¹⁸ In September 2025, SPP announced that it had cleared the backlog as it wrapped up the Phase 2 study for 2023.¹⁹ SPP reported that, since 2022, it has evaluated 1,652 projects through its cluster process, representing 340 GW of generation. In comparison, SPP's coincident peak load is approximately 56 GW.²⁰

Currently, SPP is studying its 2024 cluster, which kicked off in December 2025 and is expected to reach the facilities study phase in March 2027. Partially a product of the extended application window, the 2024 cluster is SPP's largest cluster to date and initially included 345 projects totaling 90 GW of capacity.²¹ SPP anticipates issuing GIAs for the 2024 cluster in May 2027.

SPP is skipping a 2025 cluster to allow for backlog processing. The 2026 cluster was scheduled to begin in April 2027 but, as discussed further below, will be replaced by the CPP.

Order 2023 Compliance

In compliance with Order 2023, FERC allowed SPP to retain its three-stage process, including the various timeframes for customer engagement, conducting studies, and other aspects of the study process. This includes a 180-day timeline for SPP to complete Phases 1 and 2 compared to the 150-day timeframe adopted in Order 2023. SPP was also permitted to retain other tariff provisions that are part of its three-stage process. For example, SPP was allowed to retain its study deposit framework in which interconnection customers submit the study deposit amounts specified by the Commission's pro forma, but deviates from the pro forma by making the study deposits progressively non-refundable. SPP's tariff revisions apply to the first queue cluster window that opens after the June 25, 2025, effective date of its compliance filing, which will be the first cluster under the CPP framework.²²

18 See FERC, Order Granting Waiver Request, 189 FERC ¶ 61,079 (Oct. 30, 2024).

19 SPP, [SPP Reaches Milestone in Acceleration of Generation Interconnection Requests](#) (Sept. 2025).

20 SPP, [Fast Facts - Southwest Power Pool](#) (accessed Jan. 2026).

21 SPP, [Interconnection Queue Dashboard](#) (accessed Jan. 2026).

22 In accepting the CPP framework, FERC noted that SPP's revised interconnection process under the CPP mirrors existing language in SPP's tariff that was previously accepted as part of SPP's compliance proceeding. FERC, Order Accepting Tariff Revisions, Subject to Condition, 194 FERC ¶ 61,192 at P 133 n.311 (Mar. 13, 2026).

SPP-Specific Reforms

SPP has been working to clear its queue backlog, address increasing regional demand, and prepare to implement its CPP via a suite of reforms that are underway.

In order to clear its backlog, SPP updated several aspects of its approach to managing and executing interconnection studies that make it more efficient to complete the necessary studies and provide more transparency into the process for interconnection customers, internal staff, and transmission owners. SPP credits the use of new software and automation tools as key to backlog clearing. SPP partnered with a software vendor in 2024 to develop the SPP Interconnection Management System (SIMS) for the intake of applications and interconnection request tracking throughout the DISIS process. SIMS is a cloud-based online platform that interconnection customers use to submit their application data. It enables customers, SPP, and TOs to share data and documents and to agree on milestones and timelines via a single platform. SPP reported that SIMS enabled the timely review of the 2024 cluster applications, with average application intake taking five hours per request instead of 10 hours.²³

SPP also automated creation of the base case and study power flow models for the 2021 through 2023 clusters. Use of this automation enabled SPP to reduce base case model development and creation by over two months (to two weeks down from 12 weeks).²⁴ SPP is planning to use an automation tool for steady state model solving in the Phase 1 studies for the 2024 cluster, currently underway, which is expected to significantly reduce the amount of time needed for the study.²⁵

Despite progress on the backlog, SPP concluded in 2025 that new generation has not been added fast enough to meet growing demand in the region.²⁶ SPP's load forecasts indicate rising demand from data centers, industrial expansion, and electrification. To address concerns with nearterm capacity risks before CPP is effective, SPP implemented ERAS, a one-time fast-track interconnection cluster study. The ERAS process allows only utilities, cooperatives, or other entities responsible for resource adequacy to nominate projects for fast-tracking. The responsible entity is required to commit an ERAS project's accredited capacity to its resource adequacy obligation for at least five delivery years. Nomination rights are constrained by each entity's accredited capacity shortfall, determined by its projection of resources needed to meet the planning reserve margin by 2030.

The ERAS submission window opened September 2, 2025, and closed October 2, 2025. The SPP ERAS cluster comprises 36 projects totaling 13.3 GW of new capacity. The portfolio includes 9.6 GW of thermal resources (72% of total capacity) as well as 1.7 GW of hybrid resources, 833 MW of battery storage, 639 MW of solar, and 500 MW of wind.²⁷ The ERAS cluster study is currently underway, and SPP opened the window for GIA issuance and execution on May 25, 2026. Under the current schedule, ERAS projects will be studied ahead of

23 See SPP, GI Backlog, AI, Automation, and Process Reform, [ESIG Fall Workshop](#) (Oct. 2025).

24 See *id.*

25 SPP refers to the SUGAR tool it uses for base case creation as SUGAR 1 and the SUGAR tool it is using for 2024 cluster power flow modeling as SUGAR 2. See the MISO section below for further detail regarding SUGAR.

26 FERC, Order Accepting Tariff Revisions, Subject to Condition, 192 FERC ¶ 61,062 at P 6 (July 21, 2025).

27 SPP, [Interconnection Queue Dashboard](#) (accessed Nov. 2025).

the 2024 cluster.²⁸

Critics argued that this sequencing allows ERAS projects to have a priority claim on limited transmission headroom and potentially lower incremental upgrade costs than projects in the 2024 cluster. They also argued that the ERAS rules created an undue preference for thermal generation. SPP's counterargument, which FERC accepted, is that ERAS is a one-time process that will address near-term resource adequacy needs and will serve as a bridge to a better long-term solution, SPP's CPP. The ERAS process is currently under judicial review.

SPP has proactively developed a targeted framework to address large-load interconnection requests that are paired with on-site generation while limiting impacts on the broader generator interconnection queue, establishing two complementary processes: the HILL study process and the HILLGA.²⁹ HILL is defined as a new or increased commercial or industrial load at a single site meeting specified capacity thresholds. The HILL process imposes additional study and operational requirements on qualifying loads to address reliability considerations.

For generator interconnection purposes, HILLGA creates an optional pathway for generation that is specifically designated to serve a HILL and is either co-located behind the same POI or electrically proximate. The generator and associated load are studied together on an expedited basis outside of the DISIS cluster process. HILLGA resources receive Load Limited Resource Interconnection Service, which limits the generator's output to the forecasted load of the associated HILL and does not provide general transmission delivery service. By limiting injection to the associated load and keeping HILLGA requests separate from DISIS modeling, SPP designed the process to avoid triggering restudies or increasing upgrade costs for projects in the existing queue. The HILL generator interconnection agreement terminates five years after commercial operation, after which a resource seeking to remain interconnected must submit a separate DISIS request.

The *2024 Scorecard* described SPP's transmission system as underbuilt and generally costly for interconnection customers seeking to connect. As a first step toward improvement, in 2024, MISO and SPP initiated the JTIQ process for developing backbone network upgrades to facilitate the interconnection of new generation along the MISO-SPP seam.³⁰ JTIQ is an example of an entry fee approach tied to proactively planned transmission capacity, where MISO and SPP will proactively plan network upgrades otherwise too costly for small groups of interconnection customers. MISO and SPP identified JTIQ Portfolio #1, which consists of five 345 kV transmission projects expected to enable the interconnection of 28.6 GW of new generation capacity near the MISO-SPP seam, along with other benefits to both Regions (Figure 6).

28 SPP, [Generation Interconnection Queue Study Schedule](#) (accessed Feb. 2026).

29 FERC accepted the HILL and HILLGA tariff revisions early this year. FERC, [Order Accepting Tariff Revisions, Subject to Condition](#), 194 FERC ¶ 61,031 (Jan. 14, 2026).

30 FERC, [Order on Tariff Revisions](#), 189 FERC ¶ 61,108 (Nov. 13, 2024) (JTIQ Order).

FIGURE 6 | MISO-SPP JTIQ Portfolio #1³¹



Capital costs for JTIQ Portfolio #1 (beyond a possible and unusual federal grant) will be allocated entirely to interconnection customers, an issue that has been raised for judicial review. However, instead of each interconnection customer paying for the specific project-associated network upgrades needed to accommodate their interconnection, they will pay an allocated portion of JTIQ Portfolio #1’s capital costs through a pro-rata per-MW JTIQ generator charge.³² This has the benefit of spreading the costs of more comprehensive network upgrades over multiple queue cycles; however, because the generator charges are intended to fully fund the capital costs of JTIQ Portfolio #1, generators must pay a true-up adjustment once upgrades are in service and final costs are known. This approach reduces the benefits of cost certainty of the entry fee framework because interconnection customers are expected to enter into binding commitments,

but the transmission owners are not obligated to control costs or avoid late discovery of project requirements that increase costs.³³ JTIQ Portfolio #1 upgrades are scheduled to be in service between 2031 and 2034.³⁴

Finally, SPP has been monitoring the post-GIA phase on a quarterly basis, including the timelines for construction of upgrades, and reported that the transmission providers have largely been meeting their milestones. As of February 2026, there were 227 projects, representing 40 GW, with signed GIAs in the SPP region.³⁵ At the time of the *2024 Scorecard*, interconnection customers in SPP did not identify any particular problems with construction upgrades in SPP and that trend appears to be unchanged, suggesting that proactive monitoring can be impactful.³⁶

Looking Ahead

SPP is preparing to transition to CPP—its new framework that integrates SPP’s interconnection and transmission planning processes into a single, streamlined and coordinated process that will proactively and holistically identify cost-effective regional transmission solutions within a

31 SPP, *SPP-MISO JTIQ Study* (accessed Feb. 2026).

32 The JTIQ projects will be constructed and financed by transmission owners, a financing method known as self-funding. Self-funding is unlikely to be cost-effective, but a full discussion of its merits is beyond the scope of this Report. See *Unlocking America’s Energy* at 30-31.

33 See *Unlocking America’s Energy* at 3.

34 MISO, *JTIQ Indicative Rate* (accessed Feb. 2026).

35 SPP, *Interconnection Queue Dashboard* (accessed Feb. 2026).

36 See *2024 Scorecard* at 50.

unified planning cycle.³⁷ SPP filed CPP-related tariff revisions with FERC in November 2025 and FERC accepted these on March 13, 2026. The new Generation Connection Procedures within CPP will entirely replace SPP's existing interconnection process, with full implementation in 2027.

Unlike traditional cluster-based studies, which consider only near-term needs, CPP will adopt a 20-year planning horizon that considers the region's reliability, economic, public policy, and generator interconnection needs. CPP is designed as a three-year repeating planning cycle that includes a 20-year planning assessment and subsequent 10-year planning assessments. Regional transmission planning under CPP will result in upgrades that are planned to accommodate load and future generator interconnection needs.

Under CPP, interconnection customers will pay an up-front, fixed per-MW charge, the GRID-C, to enter the queue. This charge is intended to reflect their share of the system network upgrade costs that SPP will proactively plan. Once in the queue, interconnection customers will benefit from a shorter study timeline given the narrower scope of study, focused on local network upgrades specific to the location requested. The costs of the local network upgrade for each interconnection request will be rolled into the GRID-C paid by each interconnection customer. SPP expects the CPP interconnection study to take 180 days, from the close of the cluster window to a signed interconnection agreement, as opposed to a minimum of 12 months under the DISIS process.³⁸

In exchange for the increased cost certainty and a faster, more predictable timeline, interconnection customers will be required to make an upfront cost commitment and demonstrate commercial readiness, as well as be subject to a greater financial penalty for withdrawing from the queue. This framework is intended to reduce the number of speculative projects entering the interconnection queue, which has contributed to the cascading cycle of withdrawals and restudies that created SPP's backlog.³⁹

To achieve these objectives, CPP establishes Planned Interconnection Locations for each CPP planning cycle, defined as strategically selected locations with sufficient existing or planned transmission capacity available to serve long-term generator interconnection needs. SPP reported that, as of November 2025, it had identified 680 potential Planned Interconnection Locations (PILs) that can accommodate 250 GWs of new interconnection capacity. On April 1, 2026, SPP provided a list of all PILs used in the first CPP cycle, noting that these PILs will be used for the CPP Interconnection Study Open Window.⁴⁰

Prior to opening each cluster window annually, SPP will publish the GRID-C for the applicable cluster and the list of Planned Interconnection Locations. A generator that elects to interconnect at a Planned Interconnection Location will be able to limit its system network upgrades costs to the GRID-C. Payment of GRID-C will provide SPP with certainty that generators interconnecting at these locations will contribute a share of the costs of the

37 FERC, Order Accepting Tariff Revisions, Subject to Condition, 194 FERC ¶ 61,192 at P 13 (Mar. 13, 2026).

38 SPP, Docket No. ER26-414-000, CPP Transmittal Letter at 21 (Nov. 3, 2025) CPP Transmittal Letter).

39 See *id.* at 20.

40 SPP, 2026 ITP & CPP Planned Interconnection Locations (Apr. 1, 2026).

upgrades designed to enable their interconnection.⁴¹

Planned Interconnection Locations will be capped in terms of incremental capacity based on available transmission capacity. If a location becomes oversubscribed, SPP will request that each affected interconnection customer reduce their request by a pro rata percentage or pay an additional charge to pay for incremental network upgrades.⁴²

If successful, CPP promises to deliver several benefits. First, it should accelerate interconnection timelines by avoiding repetitive restudies and building transmission capacity before congestion occurs. Second, it would provide greater cost certainty for interconnection customers before they enter the queue. Third, by requiring an upfront fixed charge, CPP would create a meaningful financial filter that discourages speculative requests, ensuring that projects entering the queue are more likely to proceed to construction. Fourth, it enables SPP to co-optimize transmission and generation, while allowing the market to continue to select specific resources, capacity, and locations, reducing the risk of stranded assets and underutilized capacity—ultimately benefitting load.

The main potential challenge and outstanding question regarding CPP is whether GRID-C will be cost prohibitive for interconnection customers and the degree to which it impacts the volume of interconnection requests. If GRID-C is too high, it may not be commercially viable for all but the largest developers, undermining the benefits that CPP is intended to provide to interconnection customers. A less likely scenario is that GRID-C is too low and therefore does not sufficiently deter speculative projects and therefore does not help keep the queue volume to a manageable level. SPP anticipates posting the initial GRID-C rate by the end of 2026.

Recommended Reforms for SPP

- ▶ Determine a reasonable GRID-C to implement the “entry fee” approach.
- ▶ Identify cost-effective reliability solutions by running power flow modeling with a tool that is capable of identifying and optimizing ATTs and publicly report the results.
- ▶ Enhance post-GIA reporting.
- ▶ Implement automation in a transparent way that supports replicability.

MISO

Incomplete progress. MISO continues to work through a large backlog of interconnection requests, having completed the 2019 and 2020 cluster studies since the *2024 Scorecard*, but it has consistently notified stakeholders of additional delays for all active clusters including

⁴¹ See CPP Transmittal Letter at 22.

⁴² See *id.* at 26-27.

the 2021, 2022, and 2023 clusters.⁴³ Similar to SPP, MISO skipped a cluster study in 2024 and is now implementing a suite of reforms, beginning with the 2025 cluster to make the queue volume more manageable. These include a zonal queue cap of 50% of load, enhanced readiness requirements beyond those required by Order 2023, and greater transparency about the capacity and locations of current queue requests.

In addition to working through the current queue, MISO is focused on achieving a one-year study timeline with the help of automation and improved project management software. However, study delays and restudies continue to be a problem despite MISO's use of automation in Phase 1 of its study process and more recent (2025) broader use of those tools. To address the power flow modeling delays, MISO has implemented some rule changes to standardize input data from interconnection customers.

MISO has continued to pursue significant regional transmission expansion, approving over \$30 billion of 345 kV and 765 kV backbone projects through Long Range Transmission Planning (LRTP) Tranche 2.1 and in coordination with SPP through JTIQ, both of which will reduce the scale of network upgrades required by current Definitive Planning Phase (DPP) studies. JTIQ is also likely to reduce the uncertainty around the amount of time associated with the Affected System Study process.

Lastly, MISO implemented a parallel ERAS serial fast lane that has been a challenging development for non-ERAS interconnection customers, given that ERAS projects and DPP projects are studied in parallel models without the other included. By design, the same transmission headroom is allocated to both types of projects, as they are not studied together. Further, recently submitted ERAS projects are moved quickly through the process in months, while DPP study cycles, particularly the DPP 2021 and 2022 cycles, suffer cumulative chronic delays and seem currently to be completely stuck, holding up later queue DPP cycles. ERAS favors utility ownership over independent power producer ownership, given that IPPs cannot directly obtain the required approval from the relevant regulatory authority. Unlike the one-time nature of the SPP ERAS process, MISO will perform quarterly ERAS studies through mid-2027.

The *2024 Scorecard* awarded MISO a "C-" citing its commitment to transmission expansion and availability of interconnection alternatives as positive aspects, while noting that MISO's process is considered unreliable and slow, with unpredictable cost outcomes.

Queue Status

MISO is currently completing studies for the 2021, 2022, 2023, and 2025 clusters⁴⁴ with the 2021 cluster scheduled to be completed in 2026 and remaining clusters in 2027. MISO conducts one system impact study in each of the three phases (i.e., a preliminary system impact study, a revised system impact study, and a final system impact study). MISO's nominal timeline for this three-phase DPP process is approximately one year, but MISO's cycles have been taking three to four years in practice.

⁴³ [DPP Schedule archives](#) document historical delays from monthly DPP schedule updates over recent years. The most current schedule was released on June 1, 2026.

⁴⁴ MISO skipped the 2024 cluster to allow time for backlog processing and refine its process for narrowing intake.

As of late 2025, MISO had reduced its overall queue backlog to 1,127 projects totaling 215 GW, down from 300 GW in early 2025.

To address the existing queue backlog for the 2022 and 2023 cycles, MISO employed automation in the Phase 1 studies. Automation of MISO's process seems to be enabling substantial timeline improvements, providing Phase 1 results, including network upgrade cost assignments, to interconnection customers within just a few months (as compared to over two years). MISO's study steps had been manual, with the most time spent on model base case data compilation and the identification of network upgrades. Once upgrades were selected, they were added back into the models and the entire process was repeated until no constraints remained. The iterative nature of this process combined with the unwieldy cluster sizes resulted in lengthy queue study timelines and delays, particularly for the largest Phase I studies.

In response to these challenges, MISO deployed automation in Phase 1 to

- ▶ Compile base case and study model input data files from its regional planning process;
- ▶ Create the base case and study models;
- ▶ Conduct power flow analyses;
- ▶ Develop network upgrade solutions and cost estimates in accordance with white papers and cost guides that MISO established; and
- ▶ Generate report appendices detailing MISO practices.

Using automation within the Phase 1 of the 2022 cluster allowed MISO to resolve study issues that were indefinitely delaying the study. Phase 1 of the 2022 cluster (MISO's largest cluster) analyzed 778 interconnection requests, totaling a nameplate capacity of 141 GW of Energy Resource Interconnection Service (ERIS) and 138 GW of Network Resource Interconnection Service (NRIS).

MISO then applied automation to Phase 1 of the 2023 cluster, with results provided in approximately 90 days, compared to prior cycles that took over two years.⁴⁵ Phase 1 of the 2023 cluster analyzed 351 interconnection requests, totaling 69 GW, for ERIS and 63 GW for NRIS.

Network upgrade cost estimates are developed during Phase 1 and are later refined in Phase 2 facility studies.⁴⁶ For the network upgrade selection, MISO developed a series of rules to automate the selection and validation of reasonable upgrades based on engineering principles documented in a white paper.⁴⁷ The white paper, which was developed following stakeholder input, outlines a framework for addressing transmission system overloads and voltage violations, as identified in Phase 1 studies.

However, the results are not a refined network upgrade analysis and need to be further reviewed in later study phases by MISO and the transmission owners. The Phase 1 study results are where interconnection customers make a "go" or "no go" decisions on projects, and interconnection customers argue that the network upgrade results provide less

⁴⁵ See [Current DPP Schedule](#) (Feb. 29, 2024).

⁴⁶ Transmission owners may not have comprehensively reviewed all proposed network upgrades during Phase 1. MISO DPP 2023 Phase I Study Report

⁴⁷ MISO, [Transmission Mitigation Selection and Cost Estimation Approach Whitepaper](#) (Jan. 2025).

cost certainty than studies using other tools. From the customer perspective, this creates challenges given that the milestone payment with automatic withdrawal penalties due at the end of Phase 1 is based on assigned network upgrade costs, and the decision whether to move forward is likely informed by initial cost estimates. Customers are also concerned that Phase 1 study inaccuracies will ultimately have to be addressed in later studies and any initial time savings will be lost. While customers are given time to review and provide alternatives to the proposed network upgrades, concerns about the quality of the Phase 1 study results are likely to persist until customers gain more experience with new tools and can see how their network upgrade cost assignment changes throughout an entire cluster cycle. This has made the need for a robust alternative mitigation process even more critical, something MISO has recognized and supports.⁴⁸

Order 2023 Compliance

MISO made its Order 2023 compliance filing, effective July 28, 2025.⁴⁹ MISO was permitted to retain its three-phase DPP process, its existing study deposit and readiness requirement framework, its existing automatic withdrawal penalty structure, and its existing surplus timing requirements. Notably, MISO allows surplus interconnection service requests to be submitted once the original interconnection customer has completed the second decision point in the DPP process, which is earlier than the Order 2023 requirement of once the original customer has an executed GIA. MISO adopted the additional requirements of the final rule, with certain modifications to accommodate its DPP process. These Order 2023 reforms will first apply to the 2025 DPP cluster.

MISO-Specific Reforms

In addition to Order 2023 compliance, MISO has been employing various reforms to make its queue size manageable and address its queue backlog, including using an automation tool (described above), increasing requirements for interconnection customers, and establishing a cap on the number of MWs that will be studied for a particular cycle.⁵⁰

Over the past two years, MISO has finalized two process reforms intended to reduce the size of the queue for future cycles. First, in January 2024, MISO adopted a set of reforms to increase milestone payments, apply automatic withdrawal penalties, remove most of the opportunities for penalty-free withdrawal due to large cost increases between studies, and expand site control requirements. MISO sought to reduce submission of speculative projects, including many interconnection customers who previously chose to withdraw their projects before initial study. Notably, the automatic withdrawal penalties apply once the DPP Preliminary Phase 1 has started, regardless of whether the withdrawal harms other customers in the queue. The penalties increase as a request progresses through each study phase. MISO first applied these reforms to the 2023 cluster study, which started in September 2025. MISO saw an approximately 50% withdrawal rate after the screening study before Phase 1 started, which MISO credits to the new 10% automatic withdrawal penalty that applies to withdrawals during Phase 1.

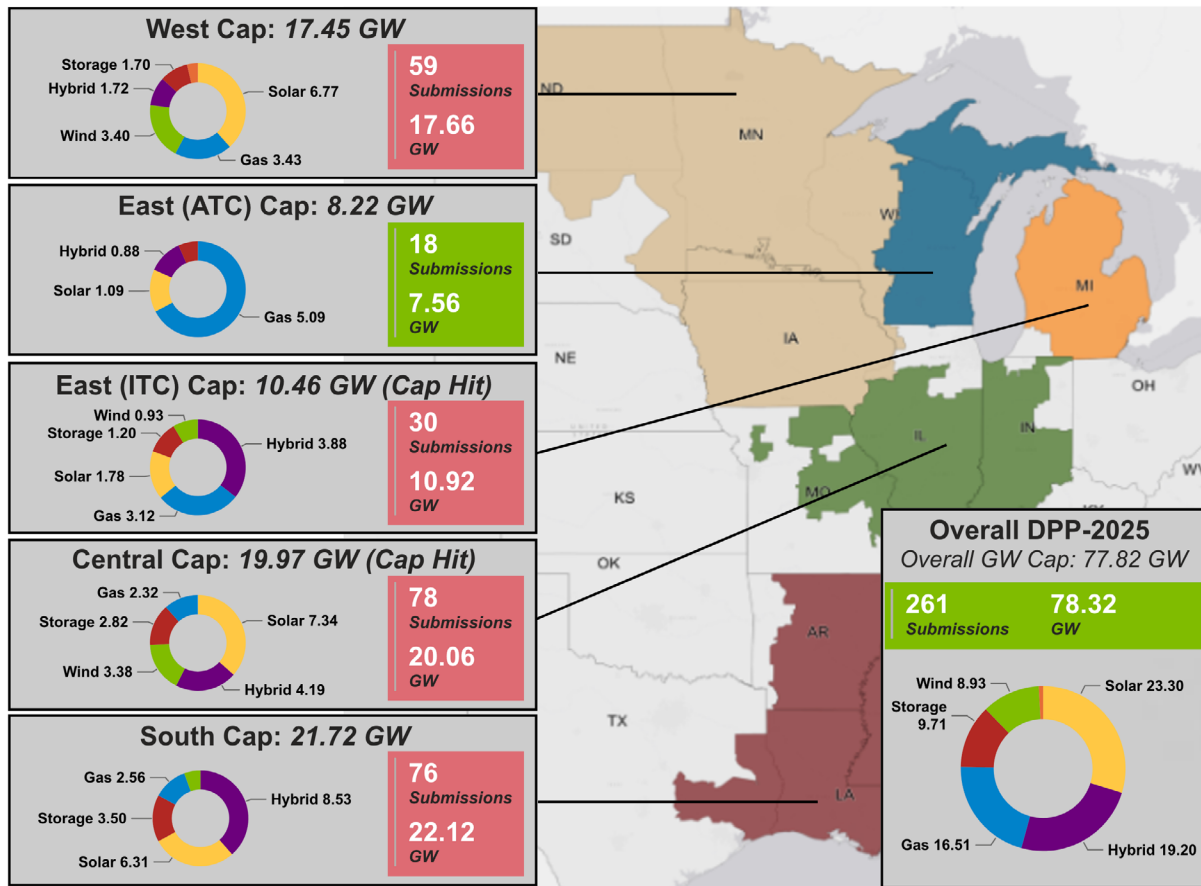
48 MISO, [SUGAR Implementation Update](#) (Apr. 2026).

49 FERC, [Order on Compliance](#), 191 FERC ¶ 61,229 (June 26, 2025).

50 MISO, [DPP-2025 Cap Tracker](#) (accessed Feb. 2026).

Second, in January 2025, MISO adopted a cap on the capacity that will be studied for a particular cluster cycle. The unprecedented 2022 DPP cluster was larger than the entire footprint-wide load, creating significant challenges. The larger the cluster, the more complicated it becomes for the study model to solve and the greater the number of re-studies required as projects withdraw. In response, MISO sought to limit the total capacity studied, based on region and a percent of the subregional peak load. Interconnection requests not included in a study cycle due to the cap will maintain their queue position in the next study cycle. These cluster caps were first applied in the 2025 cluster. Notably, MISO reached the cap in four of the five study regions, as well as the overall cap of 77.82 GW (Figure 7). MISO reported that the cap worked as intended for the 2025 cluster.⁵¹ The initial overflow into the next cluster totaled 31 GW, just shy of half the total cap.

FIGURE 7 | MISO 2025 Cluster Cap Tracker⁵²



Automation in Phase 1 of the 2022 cluster allowed MISO to resolve study issues that were indefinitely delaying the study. Phase 1 of the 2022 cluster (MISO's largest cluster) analyzed 778 interconnection requests, totaling a nameplate capacity of 141 GW of ERIS and 138 GW of NRIS.

51 MISO, DPP-2025 Cap Tracker (accessed Feb. 2026).

52 See *id.*

MISO then applied automation to Phase I of the 2023 cluster, which took approximately 90 days compared to prior cycles which took over two years.⁵³ Phase 1 of the 2023 cluster analyzed 351 interconnection requests, totaling a nameplate capacity of 69 GW for ERIS and 63 GW for NRIS.

Like other Regions, in 2025, MISO concluded that new generation has not been added fast enough to meet growing demand. In response to concerns from state regulators that MISO's standard interconnection process could not deliver new capacity in time to meet expected shortfalls, MISO proposed its ERAS process in March 2025. FERC initially rejected the filing, but a revised proposal was approved in July 2025.

MISO's ERAS is a serial process to facilitate the expedited study of certain interconnection requests. MISO established a cap of 68 interconnection requests that may be studied under ERAS. Application windows open quarterly, with no more than 15 projects admitted per window until the 68-project cap is reached.⁵⁴ A mandatory commercial operation date of June 1, 2030, is intended to ensure that the program effectively addresses near-term reliability needs. Applicants must submit verification from the relevant state regulator or other resource adequacy authority (called a RERRA) certifying a local need and confirming that the proposed project addresses that need. A transmission-owning municipality or cooperative can provide similar verifications. The program has a sunset date of no later than August 31, 2027.

MISO's ERAS has drawn criticism from many interconnection customers that note that MISO already had a well-vetted and utilized expedited interconnection process (the "Provisional GIA" option, which takes only months to complete). They also have raised concerns that IPPs are at a disadvantage in the RERRA process due to lack of any direct option or path to receive verifications from regulators. Further, ERAS projects may consume scarce transmission headroom and trigger restudies in the DPP queue depending on the timing and sequencing of the various interconnection studies. While MISO recognized the potential for transmission capacity to be allocated to both DPP and ERA projects, the Region countered stating that the simultaneous ERAS projects will not directly impact DPP models or costs.

In August 2025, the first ERAS application window attracted 49 projects representing about 27 GW. The applications were primarily made by natural gas-fired generation (74%), followed by 15% solar, 4% wind, 4% storage, and 3% nuclear. After withdrawals, 47 applications remained, from which MISO selected 10 projects for Cycle 1 studies: five natural gas plants, three solar projects, one wind facility, and one battery storage project, totaling 5.3 GW of capacity, including almost 4.3 GW of natural gas.⁵⁵ The early portfolio illustrates how ERAS's emphasis on deliverability favors thermal resources, though the inclusion of four renewable energy projects shows that non-thermal resources are not excluded by design. The 10 projects have in-service dates between January 2027 and August 2028. The remaining 37 eligible applications may be considered in future quarterly windows, subject to program limits.

MISO announced the second ERAS group in December 2025, which consisted of 15 projects totaling 6.8 GW. Seven natural gas-fired generation projects accounted for 4.8 GW, followed by

53 MISO, [Current DPP Schedule](#) (accessed Dec.19, 2025).

54 MISO increased the initial quarterly cap from 10 to 15 projects. FERC, Letter Order, 193 ¶ 61,168 (Nov. 2025).

55 MISO, [ERAS Interconnection Requests](#) (accessed Feb. 2026).

battery storage (900 MW), wind (600 MW), and solar (500 MW).

The *2024 Scorecard* highlighted MISO's commitment to transmission expansion. In terms of recent progress, MISO and SPP initiated the JTIQ process for developing backbone network upgrades to facilitate the interconnection of new generation along the MISO-SPP seam, which is described in the SPP section above.⁵⁶ In December 2024, MISO approved the LRTP Tranche 2.1 portfolio, a \$21.8 billion portfolio of 1,800 miles of 765 kV backbone transmission lines and 1,800 miles of 345 kV lines. Tranche 2.1 is expected to support the interconnection of large amounts of new resources. MISO relied heavily on Tranche 2.1 as mitigation for Phase 1 of the 2023 cycle and included Tranche 2.1 in the base case for the 2023 and 2025 cluster study cycles.⁵⁷

MISO plans to make its first of two initial tariff filings in late June 2026 for its Zero Injection Generation Interconnection Agreement (ZGIA) process, which will provide an expedited path to reach an interconnection agreement for generation that is paired with a load at the same point of interconnection and does not inject power on the transmission system. Under the ZGIA process, the load POI must be identified and a formal agreement between load and generation submitted, but the load does need to have gone through the connection agreement process. Completing the ZGIA first allows the load to be studied with the accompanying generation. MISO will cap the number of ZGIA requests that can be processed at 10 per quarter.

Finally, MISO has been tracking the amount of waiting generation that has signed a GIA but has not reached commercial operation.⁵⁸ MISO includes the amount of delayed generation, which is a subset of waiting generation that has missed the original commercial operation date. Also included is generation that is currently under construction. MISO's public database does not include the reasons for delays, but FERC filings by MISO generators to delay COD document causes such as transmission owner facility construction delays, supply chain constraints, permitting delays, and affected systems study or coordination delays. MISO's 2024 Resource Assessment showed about 40% due to transmission owner delays, 18% regulatory delays, 8% supply chain constraints, 8% economic, 11% power purchase related issues including re-negotiation which is often necessary due to queue delays, and 15% other.⁵⁹ As of March 2026, MISO's COD tracking tool reports 75.6 GW of waiting generation, 40.5 GW of which is delayed or under construction.

Looking Ahead

Going forward, MISO is optimistic that the combined impact of the various reforms and the increasing use of automation will enable the Region to meet its existing one-year timeline for the cluster process. But resolving the backlog and delays while four cycles are ongoing will not be easy. In January 2026, MISO announced that it is pushing back the timelines for the 2022, 2023, and 2025 cycles by a few months and this trend has continued every month up to the publication of this Report. The 2025 cluster kicked off in January 2026 and is currently in Phase

⁵⁶ MISO, [Generator Interconnection and Retirement - JTIQ Portfolio](#) (accessed Feb. 2026).

⁵⁷ MISO, [Response to Complaint of North Dakota Public Service Commission, Docket No. EL25-109](#) (Sept. 9, 2025).

⁵⁸ MISO's tracking tool is available to the public.

⁵⁹ See MISO, [2024 Regional Resource Assessment: A Reliability Imperative Report](#) (Jan. 2025).

1.⁶⁰ However, despite the recent reforms, backlogged study requests will create significant challenges for MISO to meet required timelines. As a result of the Order 2023 reforms, MISO could therefore face study delay penalties unless it seeks a waiver from FERC. To address power flow modeling delays, MISO is working on a rule change to standardize input data from interconnection customers. The goal is to receive a consistent set of modeling data from interconnection customers, which will enable faster and more certain study results from study software tools.⁶¹

Recommended Reforms for MISO

- ▶ Focus resources on processing DPP 2021 and 2022; delay starting the DPP 2026 until DPP 2022 is processed.
- ▶ Continue to implement automation tools while improving model accuracy and replicability for customers.
- ▶ Drive towards greater cost and schedule certainty by considering an entry fee approach.
- ▶ Track delayed transmission-owner projects and cost overruns, as well as the number of impacted GIA projects.
- ▶ Model cost-effective alternatives with power flow modeling capable of identifying and optimizing ATTs.

PJM

Expected progress. PJM is reaching the end of its lengthy transition process and has largely met its planned timeline through increased staffing and the use of new software and automation for project management. PJM started the transition in 2023, with approximately 200 GW of generation in its queue; as of February 2026, PJM had reduced its backlog to 29.7 GW. As part of these efforts, PJM is implementing additional needed reforms to its surplus interconnection service and capacity interconnection rights transfer process and has dedicated resources to tracking the post-GIA phase, including transmission-owner construction schedules. However, PJM's lengthy transition required stopgap measures including the Reliability Resource Initiative (RRI) and new Expedited Interconnection Track (EIT). While intended to meet emergency reliability needs, the high network upgrade cost assignments for RRI projects suggest that there continues to be a lack of headroom for new resources, resulting from insufficient proactive transmission planning.

The *2024 Scorecard* awarded PJM a “D-” citing a range of issues including a long transition process without opportunities for new project entry and limited system planning to create headroom for new resources.

60 MISO, DPP Schedule as of 2/1/2026 DPP Schedule (Feb. 2026).

61 MISO, Generator Interconnection Queue Improvements (PAC-2023-1) (Jan. 27, 2026).

Queue Status

In advance of Order 2023, faced with a high volume of new service requests and a mounting backlog of over 2,700 active projects (250 GW) in its queue, PJM placed a hold on new interconnection requests and transitioned its interconnection process from a serial “first-come, first-served” approach to a “first-ready, first served” cluster study approach in 2022.⁶² PJM’s reformed interconnection process (the Cycle Process) includes a three-stage System Impact Study and new readiness and site control requirements designed to reduce the number of speculative projects in the queue. As part of the transition to a cluster study approach, PJM stopped reviewing new interconnection requests, effectively closing its queue. PJM sorted existing queued requests into an expedited process and two transition cycles (Transition Cycles 1 and 2). All requests received after October 1, 2021, were intended to be studied in the first cycle (Cycle 1) of PJM’s revised process. At the time of PJM’s transition, PJM estimated that it would complete Transition Cycles 1 and 2, including GIA execution, by the fourth quarter of 2026, with the goal of largely clearing the queue backlog before commencing Cycle 1.⁶³

While PJM has adjusted certain milestone dates in the transition schedule, it is largely on track to meet the projected timeline. PJM started the transition in 2023 with approximately 200 GW of generation in its queue and, as of February 2026, had reduced its backlog to 29.7 GW. PJM has seen record withdrawals due to increased requirements for keeping a queue position, high network upgrade cost allocations, equipment procurement challenges, local permitting delays, and the length of the transition process. In 2024, 865 projects representing 74 GW withdrew pre-GIA and, in 2025, 641 projects representing 76.7 GW withdrew pre-GIA.⁶⁴ While projects withdrew for a number of reasons, a long queue wait time can become problematic, particularly for newer and rapidly improving technologies like battery storage.

PJM completed Transition Cycle 1 in September 2025, issuing 130 agreements to 17.4 GW of generation.⁶⁵ As of February 2026, of these projects, 76 executed agreements and seven unexecuted agreements were filed, for a total of 83 projects representing 14.1 GW.⁶⁶ For Transition Cycle 2, PJM completed Phase 1 in October 2025, which included 450 projects representing 46 GW. Of those, 172 projects withdrew during Phase 1, eight projects were accelerated to the draft agreement phase, and 270 projects, representing 29.7 GW, proceeded to Phase 2.⁶⁷ Phase 2 was completed in June 2026, and PJM anticipates completing Phase 3 and tendering draft agreements in early 2027.⁶⁸ Cycle 1 of the revised process closed in April 2026; there were 811 requests, representing 220 GW, with 105.8 GW of natural gas, followed by 67.5 GW of storage, 17.9 GW of nuclear, 14.8 GW of solar, 8.8 GW of hybrid solar + storage, and 4.7GW of wind. The high number of requests reflects the fact that PJM has begun processing new interconnection requests for the first time in more than four years.⁶⁹ Studies for Cycle 1 are expected to commence in July after Decision Point 2 of Transition Cycle 2

62 FERC, Order Accepting Tariff Revisions Subject to Condition, 181 FERC ¶ 61,162 (Dec. 8, 2022) (PJM Queue Reform Order).

63 PJM Queue Reform Order at PP 37-41.

64 PJM, Construction Metrics at 9 (Jan. 2026).

65 PJM, PJM Completes Interconnection Reform Transition Cycle 1 Studies (Sept. 25, 2025).

66 PJM, Interconnection Process Training at 23 (Feb. 2026).

67 See *id.* at 24 (Feb. 2026).

68 PJM, Transition Cycle 2 (Oct. 2025).

69 PJM, Planning, Interconnection Cycle Study Timeline (accessed Jan. 2026).

is completed, which is on schedule with Transition Cycle 2 Phase 2 study results that were released on June 3, 2026.⁷⁰

Order 2023 Compliance

PJM is also in the process of complying with Order 2023. PJM's initial compliance filing included multiple conceptual proposals but did not include revisions to its OATT. FERC allowed PJM to retain its three-stage System Impact Study process, including the 540-day study timeline (as compared to the pro forma LGIP's 480-day maximum timeline). However, the Commission directed further compliance on a range of issues, including directing PJM to implement transmission provider study delay penalties and adopt the requirement to evaluate advanced transmission technologies during the cluster study.⁷¹ PJM made its second compliance filing in October 2025,⁷² on which FERC acted on April 16, 2026.⁷³

Additional Reforms

PJM has taken additional steps to improve its interconnection process. For example, in March 2025, PJM removed most limitations around the use of surplus interconnection service, except when new network upgrades are required, bringing PJM more in line with other Regions that allow surplus interconnection service.⁷⁴ PJM's surplus reforms also enabled more storage resources to use surplus service by allowing AC coupling and simultaneous operation of the storage with direct connection to the grid via dedicated inverters. Previously, storage was restricted to DC connections, which prevented grid charging and many common configurations. These changes are intended to expand the use of surplus interconnection service and allow additional resources to connect to the PJM system. To date, PJM has not seen significant uptake of the product and will be an area of interest for the future.

PJM also created a separate process for transferring Capacity Interconnection Rights (CIR) from a retiring facility to an equivalent replacement resource at the same site.⁷⁵ Under the expedited process, a deactivating resource can transfer CIR to a replacement resource if it is interconnecting at the same substation and the same voltage level. The replacement resource must plan to be in service within three years. PJM reviews the replacement generation service requests on a serial basis in parallel with the Cycle process. This recently approved process is expected to streamline the interconnection of replacement generation by avoiding unnecessary study costs and shortening the related timeline.

PJM has invested in automation tools with a focus on improved project management and information sharing among PJM engineers, interconnection customers, and transmission owners.⁷⁶ PJM developed in-house tools, including Queue Destination, NextGen, PowerTemplate, and InfraTrack during the transition process. Queue Destination is an automation tool that

70 PJM, Transition Cycle 2 (June 3, 2026).

71 FERC, Order on Compliance, 192 FERC ¶ 61,077 (July 24, 2025).

72 PJM, Further Compliance Filing, Docket No. ER24-2045-004, (Oct. 2025). Per PJM's request, the tariff revisions will likely become effective at the beginning of Cycle 1, depending on when FERC issues an order.

73 See Order Accepting in Compliance in Part and Directing Further Compliance, 195 FERC ¶ 61,031 (Apr. 16, 2026).

74 FERC, Order Accepting Tariff Revisions, 190 FERC ¶ 61,083 (Apr. 14, 2025).

75 FERC, Order Accepting Tariff Revisions, 194 FERC ¶ 61,079 (Apr. 16, 2026).

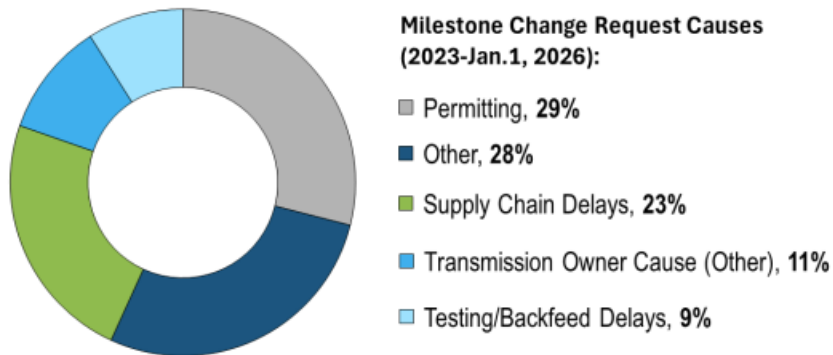
76 PJM, RTEP 2024 Plan at 23 (Apr. 2025).

centralizes project data and power flow results and performs automated cost allocation calculations. NextGen is a generation project lifecycle management tool that allows users to track interconnection requests from application to construction and to manage portfolios of projects. PowerTemplate is an automation tool that drafts GIAs and other legal documents. InfraTrack is a tool focused on managing projects after GIA execution. Designed as an internal project management tool, InfraTrack supports efforts to maintain project files, document meeting minutes and responsibilities within PJM, and track milestones.

Going forward into the Cycle process, PJM anticipates a one-to-two-year timeline for issuing GIAs and has committed to explore ways to speed the process further. The large Cycle 1 cluster will be a test of PJM’s ability to process requests faster. If it is able to stick to its one-to-two year timeline, this faster and more predictable study process will likely improve outcomes for interconnection customers.

PJM also reports that as of February 2026, 54 GW of projects have signed GIAs, but many face permitting, siting, and supply chain challenges.⁷⁷ PJM has dedicated resources to tracking the causes of construction milestone changes in the post-GIA phase since 2023 and reports these values quarterly to its Interconnection Process Subcommittee. As shown in Figure 8, permitting accounts for 29%, supply chain delays account for 23%, testing delays account for 9%, other issues on the generator side account for 28%; other issues on the transmission owner side account for 11%.⁷⁸ As noted above, PJM is also using automation for post-GIA tracking via InfraTrack.

FIGURE 8 Milestone Change Causes in PJM: 2023 Through 2025⁷⁹



■ **Other:** includes various delay such as land ownership, ownership transfer, Engineering Procurement and Construction Contractor (EPC) procurement, equipment issues, and construction delays

■ **Transmission Owner Cause (Other):** includes various delays caused by the TO such as construction delays, IA delays and network upgrade delays

■ **Backfeed:** Provided by the Transmission owner to the Project Developer’s substation to provide electrical power for testing and commissioning items prior to generator first synch. It is electrical power that flows from the PJM transmission system into a generator or project facility in a direction opposite to the intended long-term design for normal operation. This reverse flow is typically temporary, controlled, and restricted.

77 PJM, *Interconnection Process Training* (Feb. 25, 2026).

78 PJM, *2027/2028 Base Residual Auction Reserve Target Shortfall Report at 8* (Feb. 9, 2026).

79 See *id.*

To address the near-term capacity shortfall, PJM implemented its Reliability Resource Initiative (RRI) in March 2025 as a one-time, fast-track program to expedite the interconnection of up to 50 projects.⁸⁰ Under RRI, projects applied during a one-time application window in February 2025 and were studied alongside projects in Transition Cycle 2. RRI applicants had to meet strict readiness criteria so that PJM could prioritize projects with the best ability to enter commercial operation in time to address the near-term need for additional capacity.

PJM selected 51 projects totaling 9.31 GW of new construction and 2.49 GW of uprates.⁸¹ Of the 11.8 GW total, 7.75 GW (65%) are gas combined cycle resources.⁸² As noted above, in October 2025, PJM released Phase 1 study results for Transition Cycle 2, including the RRI projects. The study reveals substantial challenges—high interconnection costs and potentially lengthy transmission upgrade construction timelines—that threaten the ability of these projects to meet their target commercial operation dates. Nine projects, totaling about 6.6 GW, have interconnection cost allocations of around \$90 million or more each, with one project facing costs as high as \$1.3 billion. These financial burdens raise concerns about the feasibility of certain projects.⁸³ Although selected based on likelihood of completion, the dropout rate is similar to other queue cycles, with 28% of RRI capacity withdrawn to date.⁸⁴

The Transition Cluster 2 study results highlight that high network upgrade costs and a lack of headroom on PJM's system continue to be a persistent barrier to entry for new generation. Despite being selected for the ability to come online quickly, the RRI projects are encountering the same prohibitively high interconnection costs as the existing projects in PJM's queue. However, PJM may be beginning to see the benefits of proactive long-term transmission planning. As reported on June 3, 2026,⁸⁵ there was an \$8.7 billion decline in Cycle costs driven largely by the inclusion of Regional Transmission Expansion Plan (RTEP) Baseline Network Upgrades. The cohort costs fell to \$5.2 billion from \$15.5 billion. These figures are not final, as they represent a mid-point in the process, and it is possible they will decrease further when RTEP projects are more fully accounted for in the continuing 2026 work.

In December 2025, PJM filed its Long Term Regional Transmission Planning (LTRTP) process, adopted to comply with FERC Order No. 1920. If implemented well, these changes could improve headroom availability and lower costs for interconnection customers.

Looking Ahead

In February 2026, PJM proposed a new Expedited Interconnection Track (EIT) for state-sponsored generation with the objective of interconnecting generation to serve large loads expeditiously.⁸⁶ This 10-month process will operate separately from, and in parallel to, PJM's standard queue process. Resources can qualify for the EIT if they are greater than 250 MW, pay a \$500,000 non-refundable study deposit, have a state commitment to expedite consideration

80 FERC, Order Accepting Tariff Revisions, 190 FERC ¶ 61,084 (Feb. 11, 2025).

81 PJM, RRI Results Summary, at 6-7 (May 2025).

82 PJM, Interconnection Reform Progress Fact Sheet (June 2025).

83 PJM, Transition Cycle 2 (Oct. 2025).

84 See Claire Lang-ReE, NRDC, Unlocking Storage is the Solution to Data Center Strain (Jan. 29, 2026).

85 See PJM, n.83, *supra*.

86 PJM, Proposed Tariff Amendments for Expedited Interconnection Track, Docket No. ER26-1563-000 (Feb. 27, 2026).

of permitting and siting (a particularly controversial element given concerns about a state siting authority or chief executive expressing support for a project that has not yet been reviewed pursuant to state siting and permitting processes), a financial commitment with a load, and can reach commercial operation within three years of application submission. PJM is proposing to cap the number of projects to 10 per year. The proposal was approved by FERC on June 9, 2026, and PJM will begin reviewing projects in August 2026. How many projects will seek to utilize the EIT and how this process impacts the standard queue remain open questions.

Cycle 1 of the revised cluster process began in April 2026. Given that this is the first time that PJM will review new interconnection requests in over four years, the initial cluster size was very large. This will be the first true test of PJM's revised process and timeline, which includes new readiness and site control requirements to deter speculative projects. In 2025, PJM announced a plan to apply AI solutions to PJM's interconnection process beginning with the application review step. The goal is to accelerate the interconnection application review process using agentic AI and machine learning.⁸⁷ This assessment is intended to help PJM engineers focus on the most critical information and assess whether each application might contain deficiencies. PJM anticipates using the tools to review the potentially large number of Cycle 1 applications within the 91-day timeline for application review.

Whether PJM sees an uptick in surplus interconnection requests following its recent reforms will be an area of interest for a future scorecard. Additional reform may be needed, such as the ability for a surplus customer to obtain CIRs without going through the Cycle process.

Recommended Reforms for PJM

- ▶ Build on recent progress to proactively plan transmission to reduce and stabilize the network upgrade costs assigned to new customers.
- ▶ Adopt an entry fee approach or otherwise increase predictability of cost assignments. The recent reduction in costs is helpful to customers, but the fact that costs can be high or low and are difficult to predict may lead to suboptimal decisions by generators on whether to stay in the queue or exit.
- ▶ Track delayed transmission-owner projects and cost overruns, as well as the number of impacted GIA projects.
- ▶ Model cost-effective alternatives with power flow modeling capable of identifying and optimizing ATTs.
- ▶ Consider allowing usage of RAS, following the CAISO model (discussed below).

⁸⁷ Agentic AI refers to AI systems that go beyond responding to prompts and instead are able to plan, decide, and take actions over multiple steps and across tools.

CAISO

Promising improvements. CAISO has completed all its previous clusters through Cluster 14 (24 GW with executed or in-progress GIAs) and is currently completing Cluster 15, which was initially opened in 2023 and then re-opened in 2025. CAISO is addressing study delays through its Interconnection Process Enhancements (IPE) reforms that implement cluster studies with zonal caps and score requests based on where the system has available capacity, commercial readiness, and demand by CAISO load serving entities, among other key factors. CAISO's new scoring criteria, while the subject of criticism from customers concerned about the potential for load-serving entities (LSEs) to discriminate against IPPs, generally worked as intended for the re-start of Cluster 15. Scoring and zonal caps at 150% of available capacity allowed CAISO to focus its study on the most-ready projects while supporting competition.

CAISO further supports site selection by providing significant information prior to the interconnection application submission (heat map, POI constraint mapping) for identifying less congested portions of the system. About one-third of capacity sought energy-only interconnection, demonstrating interest in CAISO's alternative interconnection options.

CAISO regularly utilizes RAS to support interconnection but is starting to hit limits on the level of complexity they introduce. The additional information provided to interconnection customers is enabled in part by CAISO's continued proactive approval of transmission upgrades to meet the state's reliability and future resource needs. Similar to SPP, the CAISO interconnection process is well coordinated with the annual planning process to ensure regional, backbone projects are built in anticipation of new resource additions. The available capacity is then used to set zonal limits in the interconnection process. Despite this, waiting times from generator interconnection agreement (GIA) to commercial operation date (COD) remain particularly high in CAISO, largely due to permitting, procurement, and transmission completion challenges.

The *2024 Scorecard* awarded CAISO a "B" citing its high study completion rates, proactive transmission system upgrades, transparency, and cost sharing approach, while noting that study delays have become a problem.

Queue Status

In 2024, CAISO implemented significant reforms to its interconnection process in response to unprecedented queue volumes and the challenges they created. Due to the sheer size of Cluster 15—which included 541 interconnection requests totaling 347 GW submitted in April 2023—CAISO paused initial validation. To address these volume issues, CAISO adopted the IPE reforms that implement cluster studies with zonal caps and prioritize requests based on where the system has available capacity and other key factors.

As part of the IPE reforms, CAISO divided its transmission system into planning zones for purposes of processing interconnection requests.⁸⁸ CAISO defined these planning zones as

88 FERC, Order on Tariff Revisions, 188 FERC ¶ 61,225 (Sept. 30, 2024).

study areas determined in the transmission plan and used in the transmission planning process and interconnection studies, based on electrically proximate constraints, transmission, load, and supply resources. “Deliverable” planning zones are those with at least 50 MW of available deliverability based on existing and approved transmission upgrades. For each deliverable zone, CAISO admits interconnection requests into the cluster study representing up to 150% of the deliverable capacity reasonably available. Interconnection customers seeking to interconnect in a deliverable zone are eligible for reimbursement of network upgrade costs. Within these zonal caps, CAISO applies a scoring system to determine which projects advance when the combined MW total of the interconnection requests would exceed the 150% limit for the zone. Alternatively, interconnection customers can pursue interconnection in a “merchant” zone (i.e., not a deliverable zone) by funding required network upgrades at their own expense. This addresses an issue identified in the *2024 Scorecard* by determining deliverability earlier in the process; later deliverability assessments had been problematic for interconnection customers.⁸⁹

The scoring system assigns points in three categories: 1) commercial interest, measured through point allocations from LSEs and affidavits from non-LSE off-takers; 2) project viability, including site control, permitting progress, developer experience, and equipment procurement plans; and 3) alignment with system needs as defined in the California Public Utility Commission (CPUC) and California Energy Commission (CEC) resource portfolios and local capacity requirements.⁹⁰ Where scoring cannot break ties among similarly ranked projects, CAISO uses a sealed-bid auction as a last resort.

Following FERC approval of the IPE reforms, CAISO resumed Cluster 15 in October 2024 and required Cluster 15 customers to resubmit requests during the October 1–December 2, 2024, resubmission window.⁹¹ Under the revised intake process summarized above, CAISO applied zonal criteria and a weighted scoring and ranking methodology to prioritize projects within the 150% of available capacity limit for the relevant constraints/zones.⁹² CAISO reported that the scoring process meaningfully differentiated among projects and that distribution factor tiebreakers resolved ties such that no sealed-bid auctions were required in Cluster 15.⁹³

Cluster 15 outcomes suggest the scoring process effectively reduced study volumes to a more manageable level: 541 requests (347 GW) in the initial 2023 window fell to 255 complete resubmissions (118 GW), with 177 projects proceeding to validation (96 GW), and 145 projects proceeding to studies (68 GW)—an overall reduction of 73% in number of requests and 80% in requested capacity from the initial cluster.⁹⁴

Finally, CAISO’s Summary of Cluster 15 Intake Scoring Results provides initial evidence that the commercial-interest feature did not result in widespread LSE self-preferencing. Of the 171 projects seeking Full Capacity Deliverability Status (FCDS)—projects requesting deliverability for their full output—121 received zero commercial-interest points from LSEs or non-LSE off-takers. For those projects, overall scoring therefore depended on the project viability

⁸⁹ See *2024 Scorecard* at 47.

⁹⁰ CAISO, *Memorandum of Understanding Between ISO, CPUC, and CEC* (Dec. 2022).

⁹¹ CAISO, *Market Notice – Cluster 15 Application Resubmission Window* (Sept. 2024).

⁹² CAISO, *Summary of Cluster 15 Intake Scoring Results*, at 12–14 (June 2025).

⁹³ See *id.* at 12.

⁹⁴ See *id.* at 3, 19–20.

and system needs criteria. Only one LSE submitted FCDS projects in a zone with available deliverability capacity, and that LSE awarded commercial-interest points to only one of its three submissions, below the affiliate-point limitation, while allocating its remaining points to third-party projects. No LSEs submitted interconnection requests for energy-only projects.

The Cluster 15 studies are ongoing and will extend into early 2027. As a result of the Cluster 15 delay, CAISO did not accept any new requests in 2024 or 2025. CAISO anticipates opening Cluster 16 on October 1, 2026, and then following its tariff-defined annual schedule going forward.

Order No. 2023 Compliance

FERC accepted CAISO's Order 2023 compliance filing in May 2025.⁹⁵ These tariff revisions apply to Cluster 15 onward and CAISO largely adopted FERC's requirements. Notably, CAISO adopted Order 2023's prescribed study timelines with cluster application windows opening annually on October 1. FERC also accepted CAISO's relatively minor deviations needed to accommodate the IPE reforms' revised interconnection process. For example, CAISO was permitted to continue to conduct the facilities study on a clustered basis, instead of serially, to accommodate the size and overlap of shared network upgrades and interconnection facilities within CAISO's queue.⁹⁶

Other CAISO-Specific Reforms

CAISO continues to rely on RAS as an alternative to building network upgrades in cases where operational controls can address identified constraints. In CAISO's December 2023 briefing on resources available for near-term interconnection, CAISO identified 21,020 MW of incremental capacity from existing queued projects that could be enabled through RAS, including 15,573 MW of FCDS incremental capacity enabled by RAS.⁹⁷ These figures predate the restart of Cluster 15 under the IPE reforms, but they provide a sense of the scale at which RAS has contributed to available interconnection capacity. CAISO has since initiated updates to its RAS planning standards to refine eligibility and modeling requirements and to address increasing operational and market model complexity. While the updates are intended to improve reliability and market integration, they may also limit the extent to which additional interconnection headroom can be created through increasingly complex RAS configurations.

CAISO has also been working to improve transparency for interconnection customers. In 2024, CAISO launched the Grid Resource Interconnection Portal (GRIP) as a web-based system for interconnection customers to input, track, and manage interconnection requests. CAISO describes GRIP as supporting end-to-end workflow steps, including submitting interconnection requests, resolving data deficiencies, tracking study progress and required actions, calculating and communicating financial obligations, creating interconnection agreements, and tracking construction progress after a GIA is signed.⁹⁸

⁹⁵ FERC, Order on Compliance, 191 FERC ¶ 61,119 (May 15, 2025).

⁹⁶ See *id.* at P 65.

⁹⁷ CAISO, [Briefing on Resources Available for Near Term Interconnection \(Dec. 2023\)](#).

⁹⁸ CAISO, [New Tools and Tata to Support ISO's Interconnection Process \(Sept. 2024\)](#).

In parallel, CAISO released the POI heatmap (an Order 2023-required transparency tool) showing POI locations and available capacity, with interactive features and scenario filters to help inform siting and submission decisions.⁹⁹ Separately, as part of the IPE reforms, CAISO released a constraint mapping spreadsheet ahead of each cluster with information on available deliverability.

CAISO also continues to approve proactive transmission upgrades to create additional headroom. The 2024-2025 Transmission Plan identified 31 new reliability-driven and policy-driven transmission projects totaling \$4.8 billion to help accommodate 76 GW of new capacity needed by 2039 to meet policy goals and address load growth.¹⁰⁰ One of the objectives of the policy-driven assessment is to set the zonal capacities that will ultimately inform the interconnection process.¹⁰¹

However, waiting times from GIA to COD remain particularly high in CAISO, largely due to permitting, procurement, and transmission completion. LBNL's *Queued Up 2025* report indicates that the time between GIA and COD has typically been the longest in CAISO, with a typical solar project built in 2018 taking over four years.¹⁰² CAISO holds transmission development forums twice per year to provide status updates on the transmission projects previously approved through the transmission planning process and network upgrades identified in the generation interconnection process.

Looking Ahead

Cluster 16 will provide the latest test of whether the IPE reforms will continue to effectively reduce total submitted requests, direct entry towards portions of the system with available capacity, and reduce study timelines. This will be the first time since 2024 that CAISO is accepting new interconnection requests and the first time that customers will be able to consider CAISO's revised process when making initial interconnection request decisions.

Recommended Reforms for CAISO

- ▶ Improve reporting on transmission project construction progress and approaches for incentivizing faster completion of projects.
- ▶ Improve use of surplus interconnection service. CAISO requires surplus requests to demonstrate electrical independence from other queued requests, which limits surplus opportunities.¹⁰³

99 CAISO, [Points of interconnection heatmap](#), accessed Jan. 2025.

100 CAISO, [2024-2025 Transmission Plan](#), at 7 (May 2025).

101 *See id.* at. 84.

102 *Queued Up 2025* at 44.

103 *See* Miles Farmer and Abe Silverman, GridLab, [Unlocking the Power of Surplus Interconnection: Barriers, Opportunities and Strategic Solutions](#) at 22, 26 (Feb. 21, 2025).

ISO-NE

Expected progress. ISO-NE has not received as many interconnection requests as other regions and is up to date on past interconnection studies with 10 GW of projects from earlier studies that remain active, most of which have executed an interconnection agreement. ISO-NE adopted a cluster process in its Order 2023 compliance filing and initiated its transition cluster, which includes 4.8 GW of resources, with completion expected later in 2026. Its first regular cluster study is scheduled to begin in late 2026. In collaboration with the New England States, ISO-NE finalized its Longer-Term Transmission Planning (LTTP) process to identify the need for regional, multi-value upgrades and solicit competitive proposals. The first LTTP process, focused on upgrading a critical corridor between Maine and southern New England to create headroom and ultimately reduce prohibitive network upgrade costs for resources sited in Maine, is underway. Additional reforms are needed to ISO-NE's surplus interconnection rules, but ISO-NE has been open to stakeholder engagement on the issue.

The *2024 Scorecard* awarded ISO-NE at D+, noting that portions of ISO-NE's system are highly constrained, making significant system upgrade costs for interconnection customers likely despite low interconnection request volume.

Queue Status and Order 2023 Compliance

ISO-NE continues to have a relatively low interconnection volume and less of a queue backlog than other regions. Currently the majority of resources in the queue are offshore wind resources, accounting for 6 GW of the 10 GW currently active that have completed the study phase. In complying with Order No. 2023, ISO-NE adopted a cluster study process, replacing its serial process. ISO-NE started its transitional cluster study in October 2025 and plans to issue the final transitional cluster study report in August 2026.¹⁰⁴ The transitional cluster study initially comprised 23 interconnection requests totaling 4.8 GW, including 4 GW of battery storage and 500 MW (in summer capacity value) of offshore wind.¹⁰⁵ The request window for the first standard cluster study in the revised process is scheduled to open in October 2026.

ISO-NE largely adopted the additional pro forma tariff revisions in its Order 2023 compliance filing, with select deviations. FERC approved ISO-NE's 360-day study timeline, as opposed to the 300 total days required by Order 2023. ISO-NE retained its ability to perform a regional planning study on upgrades identified in the interconnection studies that support two or more interconnection requests, known as Cluster Enabling Transmission Upgrades (CETU). If a CETU is ultimately planned and constructed, interconnecting projects are allocated a share of the costs under the participant funding framework.¹⁰⁶ To date, ISO-NE has performed planning studies to identify CETUs, particularly to enable offshore wind, but none have been built.¹⁰⁷

¹⁰⁴ ISO-NE, [Transitional Cluster Study Participation](#) (Aug. 2025).

¹⁰⁵ ISO-NE, [Generator Interconnection Queue](#) (accessed Feb. 2026).

¹⁰⁶ FERC, [Order on Compliance and Tariff Revisions](#), 191 FERC ¶ 61,018 at PP 57-59 (Apr. 4, 2025).

¹⁰⁷ ISO-NE, [CETU Supported Projects](#) (accessed Feb. 2026).

One of the variations approved by FERC has continued to make surplus interconnection service an unattractive option for customers in New England. ISO-NE requires interconnection customers to obtain Capacity Network Resource Interconnection Service (CNRIS) for capacity market participation. In complying with the Order 2023 requirement for transmission providers to allow interconnection customers earlier access to surplus interconnection service, ISO-NE was permitted to retain its existing requirement that CRNIS surplus service is not available until the original generating facility has reached commercial operation. ISO-NE's rationale for this deviation is that the generating facility's capacity network resource capability is based on the performance of the resource, which is not known until the facility enters operation. LBNL's *Queued Up 2025* analysis indicates that the median duration from GIA to COD has increased to approximately 35 months for projects built in 2024, meaning surplus service tied to commercial operation can be delayed by several years.¹⁰⁸

ISO-NE Specific-Reforms

The *2024 Scorecard* noted that portions of ISO-NE's system in Maine and southeastern Massachusetts are highly constrained, making it likely that interconnection requests will trigger significant system upgrade costs.¹⁰⁹ While this report is not a transmission planning report card, proactive transmission planning directly benefits the interconnection process. ISO-NE, in collaboration with its states, developed its Longer-Term Transmission Planning (LTTP) process, a proactive, holistic planning approach that permits states to solicit solutions to transmission needs that are identified in the study. ISO-NE and its states initiated the first RFP under the LTTP process in 2024, with the goal of increasing headroom availability and reducing network upgrade costs for resources sited in Maine. In particular, the RFP sought proposals to increase the capacity of the Maine-New Hampshire interface to 3,000 MW and the Surowiec-South interface to 3,200 MW, as well as support the interconnection of at least 1,200 MW of new resources in Northern Maine. In December 2025, the Maine Public Utility Commission, in collaboration with Connecticut, Massachusetts, Rhode Island, and Vermont, issued a related RFP to procure at least 1,200 MW of new transmission capacity to connect new generation in Northern Maine with ISO-NE.¹¹⁰

Looking Ahead

ISO-NE is currently engaging with stakeholders on potential reforms to its surplus interconnection service. Surplus resources are unable to obtain CNRIS rights without going through the standard interconnection process. There is stakeholder interest in accessing CNRIS rights because deliverability and capacity market participation are important for obtaining project financing. ISO-NE's position has been that modifying surplus service to allow for the full sharing or transfer of interconnection service is not possible.¹¹¹ However, ISO-NE is conducting a gap analysis based on stakeholder feedback and may propose potential solutions to improve the surplus service.

¹⁰⁸ *Queued Up 2025* at 44.

¹⁰⁹ *2024 Scorecard* at 20.

¹¹⁰ Grid Strategies LLC, *2025 Transmission Planning and Development Report Card* at 38 (Feb. 2026).

¹¹¹ ISO-NE, *Evaluation of Surplus Interconnection Service Rules* (Jan. 2026).

Successful completion of the major reforms to ISO-NE’s interconnection process, including its first cluster study in 2026 and its first LTTP solicitation, will indicate whether ISO-NE is making progress towards improving its ability to proactively plan for and develop new capacity on its system and utilize it through its interconnection process.

Recommended Reforms for ISO-NE

- ▶ Improve surplus interconnection and generator replacement processes.
- ▶ Monitor SPP CPP and price certainty initiatives for application in the region.
- ▶ Follow and implement automation best practices as they emerge.
- ▶ Track delayed transmission owner projects, cost overruns, and the number of impacted GIA projects resulting.
- ▶ Model cost-effective alternatives with power flow modeling capable of identifying and optimizing ATTs.

NYISO

Expected progress. NYISO’s transition cluster study, the first under its Order 2023-compliant rules, is underway and has been subject to minor delays due to a large cluster size, application deficiencies, and challenges in defining the base case. In complying with Order 2023, NYISO largely retained the design of its Class Year interconnection process, now retitled the Cluster Study, and incorporated Order 2023 reforms, such as more stringent readiness requirements and elimination of the reasonable efforts standard. In addition, NYISO is working on a range of reforms to improve future clusters: providing applicants more information on system availability through a “feasibility screen;” improving its application process and interconnection portal; and updating the deliverability test methodology to increase the accuracy of network upgrade identification.¹¹²

The *2024 Scorecard* awarded NYISO a “C-,” explaining that while NYISO’s process includes reasonable study assumptions and criteria, it has not produced compelling results, with long timelines, missed schedule estimates, and unpredictable costs that come late in the process.

Queue Status and Order 2023 Compliance

In compliance with Order 2023, NYISO was permitted to retain its unique “Class Year” cluster study framework, now called the Cluster Study, with certain changes to comply with the final rule. NYISO’s process includes a single two-phased cluster study, with a decision period to enter each phase. The Phase 1 study assesses the local impacts of proposed interconnections, mainly for ERIS-level interconnection, and the Phase 2 study assesses the broader systemwide

¹¹² NYISO, *2026 Cluster Study Enhancements for Consideration at 4-6* (Jan. 2025).

impacts of proposed interconnections. Transmission owners are responsible for performing the Phase 1 study, but NYISO is responsible for developing the base case used for the study. In Phase 2, NYISO identifies any necessary upgrades, including deliverability upgrades necessary for Capacity Resource Interconnection Service (CRIS), NYISO's version of NRIS. CRIS allows the resource to meet the deliverability standard required for capacity market participation.

NYISO's Cluster Study timeline from commencement of the application window to the conclusion of the cluster study is approximately 596 days, slightly longer than the timeframe adopted in Order No. 2023 (i.e., between 495 to 585 days). In transitioning to its revised Cluster Study procedures, NYISO completed the study for the 2023 cluster (Class Year 2023) under its old rules, removed all remaining interconnection requests from its queue, and initiated a transition cluster in August 2024. All interconnection requests that were removed were eligible to resubmit to participate in the transition cluster, subject to the application requirements. NYISO is conducting the transition cluster under its revised Cluster Study framework but with certain exceptions and an extended application window to help interconnection customers adapt to the revised rules.¹¹³

NYISO does not offer surplus interconnection service because, according to NYISO, its unique interconnection rules are not compatible with such service.¹¹⁴ Whether CRIS resources should have opportunities to utilize surplus service requires further exploration.

In NYISO's process, all interconnection customers are required to obtain ERIS before CRIS. In studying resources for ERIS, NYISO permits the redispach of the facility and other facilities to the extent possible during normal operating procedures to mitigate adverse reliability impacts. If the resource's output is reduced and no system upgrades are required to address reliability, NYISO does not identify any upgrades. According to NYISO, this ERIS process reduces the cost burdens for interconnection customers by making the need for network upgrades less likely.¹¹⁵ In contrast, CRIS customers do not receive full upgrade costs until the end of the process and, as reported in the *2024 Scorecard*, the information can lack clarity.¹¹⁶ How NYISO manages these processes as its queue continues to grow will be an area of interest for future assessments.

While NYISO's queue has not experienced the same influx and resulting backlog as other Regions, the recent uptick in interconnection requests has created challenges. NYISO's transition cluster initially included more than 300 projects representing over 60 GW of capacity. In comparison, the 2023 cluster started with 70 interconnection requests and 35 projects proceeded to the GIA stage. As of January 2026, the transition cluster Phase 2 study included 92 projects representing 15.6 GW of capacity. NYISO has identified application deficiencies, increased withdrawals, and base case management as contributors to study timing challenges.¹¹⁷ This is consistent with the *2024 Scorecard*, which noted that interconnection customers reported difficulty in interpreting NYISO's submission requirements and as a result experienced more deficiency notifications than in other Regions.¹¹⁸ Regarding base case management, NYISO

113 FERC, Order on Compliance, 191 FERC ¶ 61,049 (Apr. 17, 2025).

114 FERC, Order on Compliance, 170 FERC ¶ 61,117 at P 98 (Mar. 19, 2020).

115 See *id.*

116 See *2024 Scorecard* at 37.

117 NYISO, *2026 Cluster Study Enhancements for Consideration* at 4-6 (Jan. 2025).

118 See *2024 Scorecard* at 48.

reported that the number of projects in earlier clusters requesting COD extensions impacted the transition cluster base case and created uncertainty about headroom availability. NYISO anticipates completing Phase 2 in August 2026, followed by a final decision period extending through October 29, 2026.¹¹⁹ The next cluster application window (Cluster 2026) is scheduled to open on July 31, 2026.

Other NYISO-Specific Reforms

In August 2024, NYISO launched a new interconnection portal. This digital platform allows developers and utilities to submit and access information on pending interconnection applications and enhances overall transparency and information sharing for all parties. The portal also enables developers to more easily request information and assistance from NYISO. NYISO developed the portal in response to stakeholder recommendations regarding its prior interconnection portal.¹²⁰

New York State launched the Coordinated Grid Planning Process (CGPP) in 2023 to better align local, regional, and interconnection planning processes. The CGPP established a framework for identifying and evaluating transmission investments needed to accommodate expected generation development and policy goals. Through coordination from NYISO, NYSERDA, Department of Public Service Staff, and other stakeholders, the process evaluates potential upgrades that could relieve transmission constraints, improve deliverability, and support efficient generator interconnection. The CGPP is expected to culminate in an initial set of recommended investments for New York Public Service Commission consideration and the first cycle report is expected in August 2026 with the decision period for customers running to October 2026.¹²¹ Worth watching is whether the recommendations identify actionable transmission upgrades that ultimately improve system headroom and account for interconnection needs.¹²²

Looking Ahead

Through its stakeholder process, NYISO is considering a set of cluster study enhancements in response to lessons learned during the transition cluster. These enhancements focus on reducing study inefficiencies and minimizing application cure periods. NYISO has identified repeated application deficiencies, increased withdrawals, and base case management as contributors to study timing challenges.¹²³ Proposed refinements include a simplified interconnection request form, more stringent rules for COD extensions, and process improvements aimed at reducing restudy risk in subsequent phases.¹²⁴ Separately, NYISO is evaluating potential revisions to its deliverability test methodology for projects seeking CRIS. NYISO has identified methodological issues relating to base case setup, capacity derating for

119 NYISO, *Public Dashboard for Transition Cluster* (Jan. 2026).

120 NYISO, *Aspiring Generation Projects Advance Through a New NYISO Interconnection Process* (Apr. 2025).

121 NYISO, *2026 Power Trends* at 28 (2026).

122 See Grid Strategies LLC, n. 110 at 36-37.

123 NYISO, *2026 Cluster Study Enhancements for Consideration* at 4-5, 14 (Jan. 5, 2025) (identifying application deficiencies, cure period extensions, dispute resolution impacts, and base case lockdown issues affecting study timelines).

124 See *id.* at 9, 11, 14.

storage resources, and interface modeling.¹²⁵

NYISO has also initiated reforms to its pro forma Standard Interconnection Agreement and related construction agreements. Stakeholder materials note a substantial increase in the number of agreements and amendments under negotiation, resulting in longer execution timelines and an increase in nonconforming filings at FERC.¹²⁶ NYISO has proposed revisions intended to streamline negotiations, clarify recurring provisions, and improve administrative efficiency, with a target implementation timeline aligned with the next cluster cycle.¹²⁷

The next cluster cycle will serve as an important indicator of whether NYISO's proposed enhancements reduce deficiency iterations and withdrawal-driven delays.

Recommended Reforms for NYISO

- ▶ Drive towards more certainty in cost assignment, potentially through an entry fee or zonal approach.
- ▶ Increase utilization of alternative solutions (such as RAS and GETs) to reduce network upgrade needs and provide granular power flow modeling of ATTs.
- ▶ Provide transparency on post-GIA progress.
- ▶ Incorporate automation.

ERCOT

Continued Advantage with Incremental Progress. ERCOT's unique process continues to get high marks for processing a high volume of resources that reach the GIA stage on a reasonable timeline and at reasonable costs. This has continued with 16.7 GWs of projects energized since January 2024 with no current backlog of interconnection studies. ERCOT has recently approved over \$30 billion in 765 kV lines that, while intended to help serve large loads, are expected to improve headroom for generator interconnection customers in West Texas, which has long been plagued by significant constraints. The most notable change is that effective January 1, 2026, ERCOT adopted a policy that assigns a share of network upgrade costs above a standard allowance to interconnection customers, instead of being covered entirely by transmission providers. The standard allowance of \$20 million for interconnections at voltages greater than 138 kV is intended to cover typical ERCOT interconnection costs, so impacts to customers should be relatively small. ERCOT is also experiencing an unprecedented influx of large load interconnection requests, which, given overlapping modeling and staff workload requirements, may impact generator interconnection process timelines.

¹²⁵ NYISO, *Deliverability Test Methodology Considerations* at 12-14 (Jan. 2026).

¹²⁶ *See id.* at 8-11.

¹²⁷ *See id.* at 13, 21.

The *2024 Scorecard* awarded ERCOT a “B,” citing its relatively high throughput and reasonable interconnection timelines, while flagging transmission constraints and curtailment risk as ongoing structural concerns.

Queue Status

ERCOT is not within FERC’s jurisdiction and therefore was not required to comply with Order 2023. ERCOT continues to have a distinct interconnection process often referred to as “connect and manage.” The concept is similar to ERIS in that projects are not required to satisfy the study and upgrade requirements to meet capacity delivery standards, given ERCOT’s lack of a centralized capacity market. This framework places a higher degree of grid congestion risk on the developer, including a need to manage higher anticipated levels of economic curtailment. As noted in the *2024 Scorecard*, the biggest development risk driving withdrawals in ERCOT is anticipated congestion and not the system upgrade costs resulting from interconnection studies.¹²⁸

ERCOT continues to process a large volume of generation interconnection requests. ERCOT’s Monthly Operational Overview for December 2025 reports 1,984 active generation interconnection requests totaling approximately 441 GW, with solar and battery storage comprising the majority of this total.¹²⁹ LBNL’s *Queued Up 2025* report shows that ERCOT executed interconnection agreements amounting to more than 30% of its peak load in 2024 and maintains one of the highest shares of requests reaching the GIA stage.¹³⁰ LBNL data further indicate that ERCOT’s interconnection request-to-GIA timelines and GIA-to-COD timelines are typically shorter than those in FERC-jurisdictional Regions.¹³¹ The shorter timelines are partially due to the fact that siting and permitting requirements are comparatively less demanding in Texas than in other states.

ERCOT-Specific Reforms

Effective January 1, 2026, ERCOT implemented a revised interconnection cost responsibility framework.¹³² Under this rule, interconnection customers are responsible for interconnection facility costs incurred by transmission service providers (TSP) that exceed a defined allowance, while transmission system upgrades remain the responsibility of the TSP.¹³³ The policy is intended to incentivize interconnection customers to minimize costs by siting generators close to existing transmission infrastructure. The allowance is set at \$14 million for interconnections at or below 138 kV and \$20 million for interconnections at voltages above 138 kV.¹³⁴ The standard allowance is intended to cover typical ERCOT interconnection costs, which are generally lower than in other Regions where upgrade costs are likely to exceed \$20 million per project.

128 See *2024 Scorecard* at 46.

129 ERCOT, *Monthly Operational Overview December 2025*, at 5-6 (Jan. 2026).

130 See *Queued Up 2025* at 25.

131 See *id.* at 40, 45.

132 16 Tex. Admin. Code § 25.195 (2026).

133 *Id.* at § 25.195(f)(3).

134 *Id.* at § 25.195(f)(3)(A)(i)-(ii).

The rule also establishes enhanced reporting requirements for interconnection cost data. TSPs must provide monthly interconnection cost data to ERCOT beginning January 2026 and ERCOT must publish an annual interconnection cost report beginning April 2027.¹³⁵

ERCOT's long-term transmission planning continues to expand capacity in response to load growth and system constraints. However, the most significant expansion of transmission is being driven by a legislatively mandated long-term study for serving future load and is not based on the annual planning process. ERCOT's 2024 Regional Transmission Plan and associated Strategic Transmission Expansion Plan materials evaluate large-scale backbone transmission development, including 765 kV transmission projects.¹³⁶ While these investments are primarily driven by reliability and load integration needs, expanded backbone infrastructure may improve long-term headroom and reduce congestion over time, addressing concerns identified in the *2024 Scorecard* regarding ERCOT's lack of proactive transmission planning.¹³⁷

Looking Ahead

How implementation of the new interconnection cost responsibility framework will influence project economics and queue participation going forward is an open question. At the same time, ERCOT's transmission expansion initiatives will shape future system headroom and congestion outcomes. ERCOT is also experiencing an unprecedented 232 GW of large load seeking to interconnect, which, given overlapping modeling and staff workload requirements, may impact generator interconnection process timelines. ERCOT is considering a cluster study process for large loads to determine the amount of requested load that can be reliably served each year over a six-year period and the transmission upgrades needed to accommodate the full load request. Whether ERCOT can maintain its historically strong interconnection throughput while addressing transmission constraints and large load additions will be central to future assessments.

Recommended Reforms for ERCOT

- ▶ Proactive transmission planning and buildout to reduce congestion and curtailment risk after projects are connected.

¹³⁵ *Id.* at § 25.195(i)(1)-(2).

¹³⁶ ERCOT, 2024 RTP 345-kV Plan and Texas 765-kV Strategic Transmission Expansion Plan, at i-iii (Jan. 2025).

¹³⁷ 2024 *Scorecard* at 20 (Table 2).

CONCLUSION

Regions have all placed a very large emphasis on speeding up generator interconnection over the last two years. By requiring adoption of a cluster study approach and setting enforceable timelines, FERC Order 2023 has helped bring all FERC-jurisdictional Regions up to a basic level of improved performance. Many Regions have taken separate steps to further speed the process by introducing new tools, clarifying alternative pathways, and making various adjustments to the cluster process itself.

Yet predictability of cost and timing is still a challenge in all Regions. Recent innovations such as SPP's CPP and CAISO's zonal approach could prove to be models if implemented well, and this report recommends that other Regions begin exploring similar approaches to improve cost and schedule certainty through proactive planning for both transmission and generator interconnection needs.

Instead of (or alongside) these more proactive approaches, some Regions have turned to fast-track policies that can create tension and potential for discrimination between the regular queue and the alternative fast track queue, between project ownership type (utility vs IPP), and between fuel types. It is better to speed up and improve the whole queue without offering special treatment to certain types of resources.

One promising approach is to leverage automation technology that is rapidly improving and likely to speed all aspects of the interconnection process, from intake management and workflow coordination to more complex base case construction and modeling tasks. However, the application of these tools to the interconnection process is a novel challenge, and use of different models can cause challenges for customers trying to predict and replicate results. Greater transparency and alignment of modeling assumptions and methods could help.

In addition to speeding interconnection through faster processing, it is also possible to speed up grid connections by reducing the need for costly and time-consuming network upgrades. While Order 2023 required consideration of ATTs, opportunities for use of existing interconnection capacity and ATTs could be expanded in most regions.¹³⁸

Finally, barriers outside of Regional interconnection process are becoming binding, such as network upgrade construction, access to electrical equipment, and state and local permitting. Simplifying and speeding up the interconnection process can better enable interconnection customers and transmission owners to address those challenges. At the same time, better data collection about delays and cost overruns that occur after an interconnection agreement is signed will allow FERC, Regions, and states to take action to address the source(s) of delay.

Since issuance of the *2024 Generator Interconnection Scorecard*, the interconnection process has improved substantially, but not sufficiently. And in the intervening time, the need for speed

¹³⁸ FERC underscored the importance of taking a "hard look" at ATTs to expedite interconnection of new load and new generation in the show cause orders issued to the Regions in Docket Nos. EL26-67-000, et al. during the June 18, 2026, Open Meeting.

has only grown. But so has the solution set. And with all Regions now implementing yesterday's best practices in the form of Order 2023 compliance, the industry can turn to the unending and essential task of continuous, iterative improvement. The priority reforms in the *2026 Generator Interconnection Interim Progress Report* offer a roadmap for that effort.



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Grid Strategies LLC is a power sector consulting firm helping clients understand the opportunities and barriers to integrating clean energy into the electric grid. Drawing on extensive experience in transmission and wholesale markets, Grid Strategies analyzes and helps advance grid integration solutions.

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