Generator Interconnection Scorecard

Ranking Interconnection Outcomes and Processes of the Seven U.S. Regional Transmission System Operators

February 2024

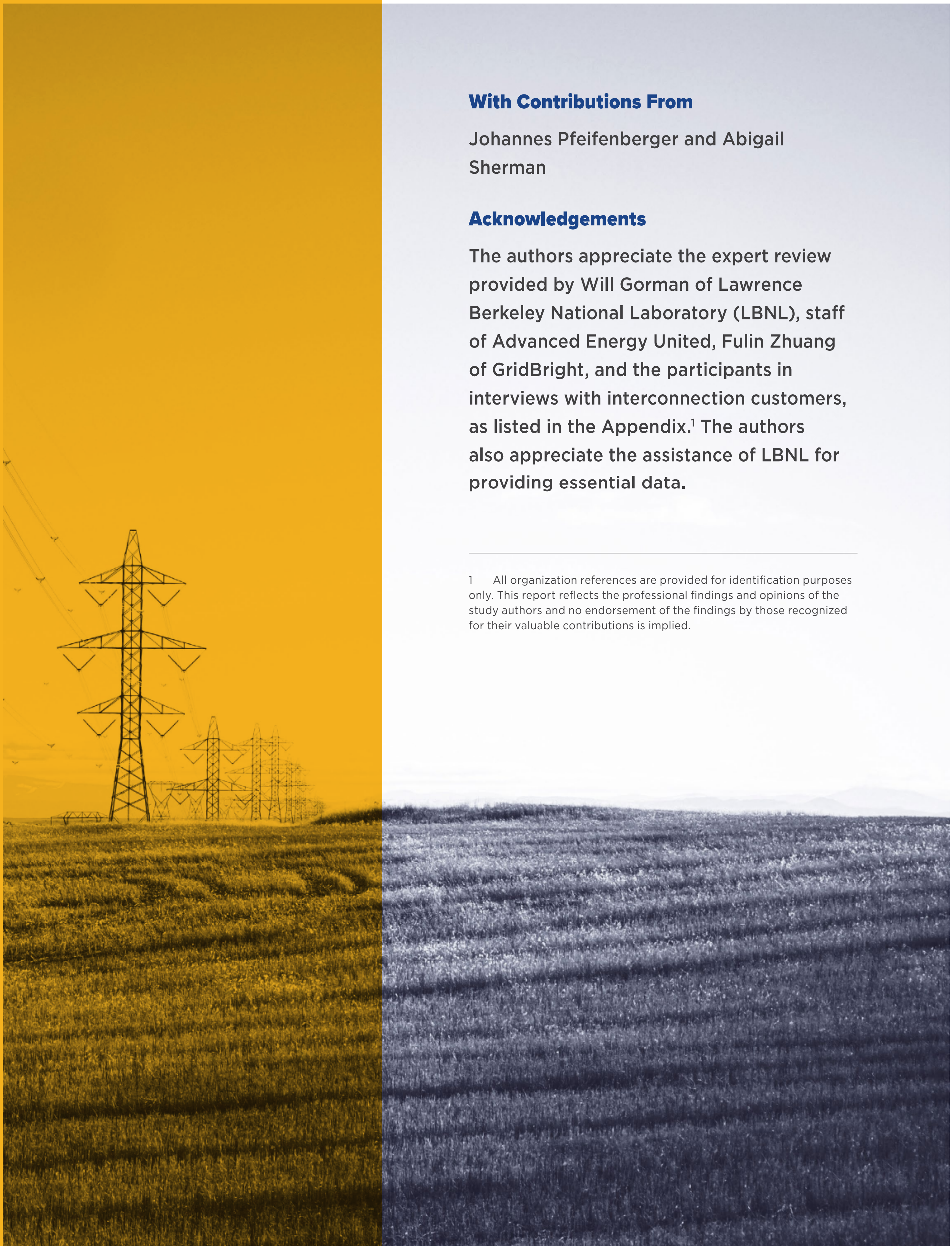
Authors | John D. Wilson, Richard Seide, Rob Gramlich, and J. Michael Hagerty

ADVANCED ENERGY UNITED™

Prepared for Advanced Energy United with funding from the Advanced Energy Institute

Grid Strategies

Brattle



With Contributions From

Johannes Pfeifenberger and Abigail Sherman

Acknowledgements

The authors appreciate the expert review provided by Will Gorman of Lawrence Berkeley National Laboratory (LBNL), staff of Advanced Energy United, Fulin Zhuang of GridBright, and the participants in interviews with interconnection customers, as listed in the Appendix.[1] The authors also appreciate the assistance of LBNL for providing essential data.

---

1 All organization references are provided for identification purposes only. This report reflects the professional findings and opinions of the study authors and no endorsement of the findings by those recognized for their valuable contributions is implied.

CONTENTS

EXECUTIVE SUMMARY

There are over two million megawatts of generation and storage projects actively seeking to connect to the U.S. transmission grid, a backlog caused in large part by grid interconnection processes that observers have characterized as dysfunctional. These generator interconnection processes have been well-scrutinized over the past few years across the U.S. power system due to the significant delays and limits set on new resources seeking to interconnect. Each grid operator's interconnection process is different, and the hurdles to improvement vary accordingly.

The *2024 Advanced Energy United Generator Interconnection Scorecard* is the first-ever attempt to evaluate each of the seven regional transmission system operators (Regions) on their generator interconnection processes. Based on a survey of interconnection customers with experience navigating these processes and analysis of the recent results of the interconnection process, each Region was assigned a grade across six categories, with the overall grades presented in Table ES- 1.

TABLE ES- 1 Generator Interconnection Scorecard Grades

	Overall Scorecard Grade
CAISO	B
ERCOT	B
ISO-NE	D+
MISO	C-
NYISO	C-
PJM	D-
SPP	C-

The Scorecard confirms the widespread recognition, including by the Federal Energy Regulatory Commission and the Regions, that the generator interconnection process is not working effectively and efficiently to allow new generation and storage resources access to the transmission network. Need for new resources is being driven by several factors including growing demand due principally to new large loads, electrification of the building and transportation sectors, project economics, state policies, and climate trends affecting renewable energy and weather-sensitive end uses of electricity such as building heating and cooling. In response to this demand, developers of new resources have requested generator interconnection for many projects, placing them in queues to be studied, resulting in the identification and construction of transmission facility upgrades. As is widely recognized, and this Scorecard confirms, the progress towards completing those interconnections is slow and puts system reliability at risk.

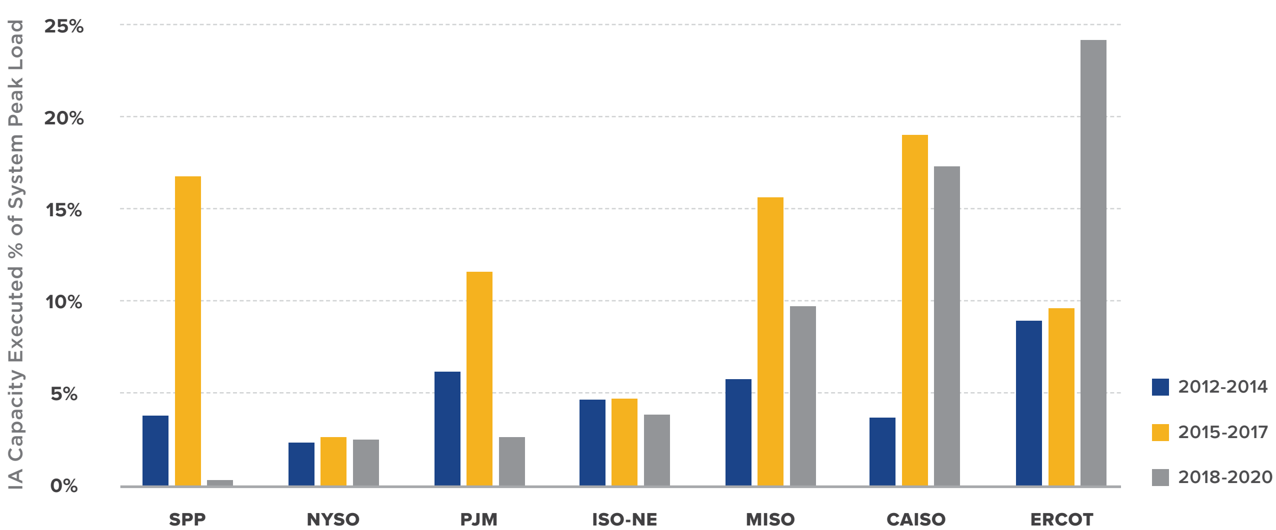
The two Regions with the best scores are the Electric Reliability Council of Texas (ERCOT) and the California Independent System Operator (CAISO). ERCOT and CAISO are graded "B" for different reasons, as these two Regions have very different processes for new resources to be reviewed and connected to an electric transmission system.

ERCOT has a relatively fast and consistent interconnection process, with reasonable costs, although challenges to transmission network upgrade construction can slow the process towards the end and result in curtailment of projects that do get built. As large queue volumes slowed processing rates across the country, ERCOT was singularly able to maintain a high processing speed and scale up the total capacity that received interconnection agreements and, hence, permission to proceed towards project operation.

For projects submitted before 2020, CAISO also had a relatively fast and consistent process. Since then, CAISO's process has been unable to efficiently process applications due to the large increase in the number of new generator interconnection applications. In contrast, ERCOT was singularly able to maintain a high processing speed and scale up the total capacity that received interconnection agreements and, hence, permission to proceed towards project operation.

The relatively high grades for ERCOT and CAISO are driven by interconnection process results. This part of the Scorecard's evaluation considered the success rate and speed that applications move to complete the process, as well as the reasonableness and certainty of interconnection costs. As shown in Figure ES- 1, ERCOT and CAISO completed interconnection agreements for more capacity of new generators by the end of 2022 for applications submitted in 2018-2022 than the other five Regions.

FIGURE ES–1 | **Interconnection Agreements Executed Through 2022 for Interconnection Requests Submitted from 2012-2020[2]**



2 Analysis of LBNL, *Queued Up* dataset.

ERCOT also clearly led the other Regions with respect to reasonableness and certainty of costs, since interconnection customers in ERCOT are only assigned certain limited cost responsibilities related to connecting the transmission system. Even though average interconnection costs in CAISO are not lower than other Regions, the Scorecard grades for CAISO emphasize the relative certainty of costs for interconnection customers due to transparency practices and the likelihood that much of the interconnection costs will eventually be refunded to the project developer.

Much lower grades are given to the Independent System Operator of New England (ISO-NE), Midcontinent Independent System Operator (MISO), New York Independent System Operator (NYISO), PJM Interconnection (PJM), and Southwest Power Pool (SPP). While MISO, NYISO, and SPP each received good grades for certain components of their interconnection process, all five Regions ended up with grades lower than "C."

In addition to evaluation of the interconnection process results (Category 1 in Figure ES- 2), the overall Scorecard grade for each of the Regions is based on an evaluation of components of the generator interconnection process grouped into four categories (Categories 2-5) , and an additionalcategory that evaluates the effectiveness of regional transmission planning in supporting and coordinating with the generator interconnection process (Category 6). All six categories are summarized in Figure ES- 2.

FIGURE ES–2 | Generator Interconnection Scorecard Categories

1 Generation Interconnection Process Results

- Success Rate and Speed
- Cost Reasonableness and Uncertainty

2 Pre-Queue Information

- Availability and Quality of Useful Information for Preparing Applications
- Availability of Transmission Provider to Address Questions
- Information Provided by Regions to Conduct Pre-queue Injection Modeling

3 Interconnection Process Design

- Process Structure
- Process Transparency
- Staffing and Modeling Resources
- Construction of Network System Upgrades

4 Assumptions, Criteria, Replicability

- Transparency of Criteria and Assumptions
- Reasonableness of Criteria and Assumptions
- Consistency of Modeling Characterization
- Consideration of Grid Enhancing Technologies
- Alignment with Distribution Studies
- Coordination with Neighboring Systems
- Transmission Provider Study is Accurate and Coordinated with Region

5 Availability of Interconnection Alternatives

- Attractiveness of Energy Resource Interconnection Service
- Opportunity for Interconnection Needs to be Addressed by "Simple" Remedial Action Scheme
- Ease of Sharing and Transferring Existing Points of Interconnection

6 Using Regional Transmission Planning

- Region-planned Transmission Supports Interconnection
- Regional Transmission Planning Considers Upgrades Identified Through Interconnection Studies

The Scorecard is not the first report to recognize considerable shortcomings affecting generator interconnection. The Scorecard is being completed during a significant transition in interconnection processes in response to the large increase in interconnection requests over the past decade and the resulting delays and other complications in completing the processes.

Currently, most of the Regions are undergoing significant efforts to reform their interconnection practices and policies in response to stakeholder concerns and FERC Order No. 2023. The Scorecard is not an assessment of those ongoing or recently adopted reforms that have not yet impacted the generator interconnection processes. And further, the U.S. Department of Energy has released a draft roadmap to address interconnection challenges through its Interconnection Innovation e-Xchange (i2X) process.[3] While this report does reference FERC Order 2023 and ongoing reforms, future Generation Interconnection Scorecards may track the effects of those reforms. The Scorecard may be updated periodically, and this first-ever Scorecard will provide a baseline against which to evaluate the effectiveness of changes implemented to the generator interconnection processes as a result of the current efforts.

3 Find updates on the i2X website here: https://www.energy.gov/eere/i2x/interconnection-innovation-e-xchange

1 THE PURPOSE OF THE GENERATOR INTERCONNECTION SCORECARD

The 2024 Advanced Energy United *Generator Interconnection Scorecard* is the first-ever attempt to evaluate each of the seven regional transmission system operators on their generator interconnection processes. Referred to as the "Regions" in this report, the seven organizations graded in the Scorecard are California Independent System Operator (CAISO), Electric Reliability Council of Texas (ERCOT), Independent System Operator of New England (ISO-NE), Midcontinent Independent System Operator (MISO), New York Independent System Operator (NYISO), PJM Interconnection (PJM), and Southwest Power Pool (SPP). The Scorecard evaluates each Region's interconnection process in its entirety, from the information exchange that occurs prior to submitting an application (pre-queue) to network upgrade construction activities that occur after interconnection studies and agreements are complete, which are primarily the responsibility of a transmission provider.

The Scorecard assigns a grade to each of the Regions on six categories related to the generator interconnection process. As discussed in Section 3.2, the Scorecard relies on publicly available data and on interviews with 12 generation developers and engineering firms. The resulting grades reflect the generator interconnection processes as they have performed over the past several years — it is a look back, not a look forward. The sole exception to this is for the regional planning category grade; this category also considers activities that are *underway* to upgrade the transmission system proactively, even if those upgrades have not yet had a direct impact on the generator interconnection process.

The Scorecard is being completed during a significant transition in interconnection processes in response to the large increase in interconnection requests over the past decade and the resulting delays and other complications in completing the processes. Currently, most of the Regions are undergoing significant efforts to reform their interconnection practices and policies in response to stakeholder concerns and FERC Order No. 2023. The Scorecard is not an assessment of those ongoing or recently adopted reforms that have not yet impacted the generator interconnection processes. The Scorecard may be updated periodically, and this first-ever Scorecard will provide a baseline against which to evaluate the effectiveness of changes implemented to the generator interconnection processes as a result of the current efforts.

2 THE GENERATOR INTERCONNECTION PROCESS

Generator interconnection is the process for new electric resources, including energy storage, to be reviewed and connected to an electric transmission system.[4] It is a highly technical process, and this section of the report explains key components of the process and defines some technical terms necessary to explain the Scorecard grades.

While the multi-step, multi-year interconnection process varies significantly from one transmission provider to another, there are common elements across all of the processes. With the exception of ERCOT and the federal power marketing administrations, all generator interconnection processes are regulated by the Federal Energy Regulatory Commission (FERC). Many parties are involved in this process, including an **interconnection customer** (the resource developer), a **transmission provider** (a transmission operator that is not an ISO, RTO, or ERCOT), and, in much of the country, one (or more) of the **Regions**. In those parts of the country where the transmission system is not operated by a Region, interconnection applications are reviewed by **non-RTO/ISO transmission providers**, often vertically-integrated utilities.[5]

While interconnection procedures vary by Region, the interconnection process generally involves several key components:

1. **Pre-queue.** The initial project development phase in which an interconnection customer identifies a potential need or market for power, identifies a potential site, and selects a potential point of interconnection to the transmission system.

4 Note: There is a separate, state-jurisdictional interconnection process followed by resources seeking to interconnect to the low-voltage distribution system. This report is focused on transmission system interconnection and does not consider state distribution system interconnection processes.

5 The Scorecard includes occasional discussion of generator interconnection processes of non-RTO/ISO transmission providers. The large number of such systems precluded a comparable analysis for this report.

2. **Interconnection application.** The interconnection customer submits an application to the transmission provider and, where applicable, the regional transmission system operator. The application contains essential information about the proposed project along with technical models describing its proposed operation.

3. **Interconnection study process.** : The transmission provider and, where applicable, the regional transmission system operator, evaluate the impact of the project on the transmission system in a series of studies. These studies include assumptions about the performance of generators on the system as well as electrical load conditions. Prior to recent reforms and especially FERC Order 2023, many study processes evaluated projects in a serial queue – each project evaluated assuming that the earlier queued projects would be put into commercial operation, with costs assigned to the single project that triggered each required network upgrade. Order 2023 requires that all projects be studied in clusters: a group of projects is evaluated for collective impact, with necessary upgrade costs shared based on the proportional impact of each project. Various points in a study process specify milestone requirements (e.g., readiness requirements) and deposit amounts. If the milestone requirements cannot be met or the interconnection customer determines that estimated interconnection costs do not justify paying an additional deposit, the project may be withdrawn from the queue. Withdrawals may change the system model sufficiently to require a restudy for other projects in the queue, thus impacting the interconnection costs and timing of those remaining projects.

4. **Interconnection agreement.** A generator interconnection agreement is a contract between the interconnection customer, transmission provider, and, where applicable, Region. It specifies the operational terms and cost responsibilities for both interconnection facilities and network upgrades. These terms and costs are outcomes of the study process, intended to ensure that connecting the generator to the grid does not have adverse effects. The contract may also discuss other related matters such as network upgrade schedules.

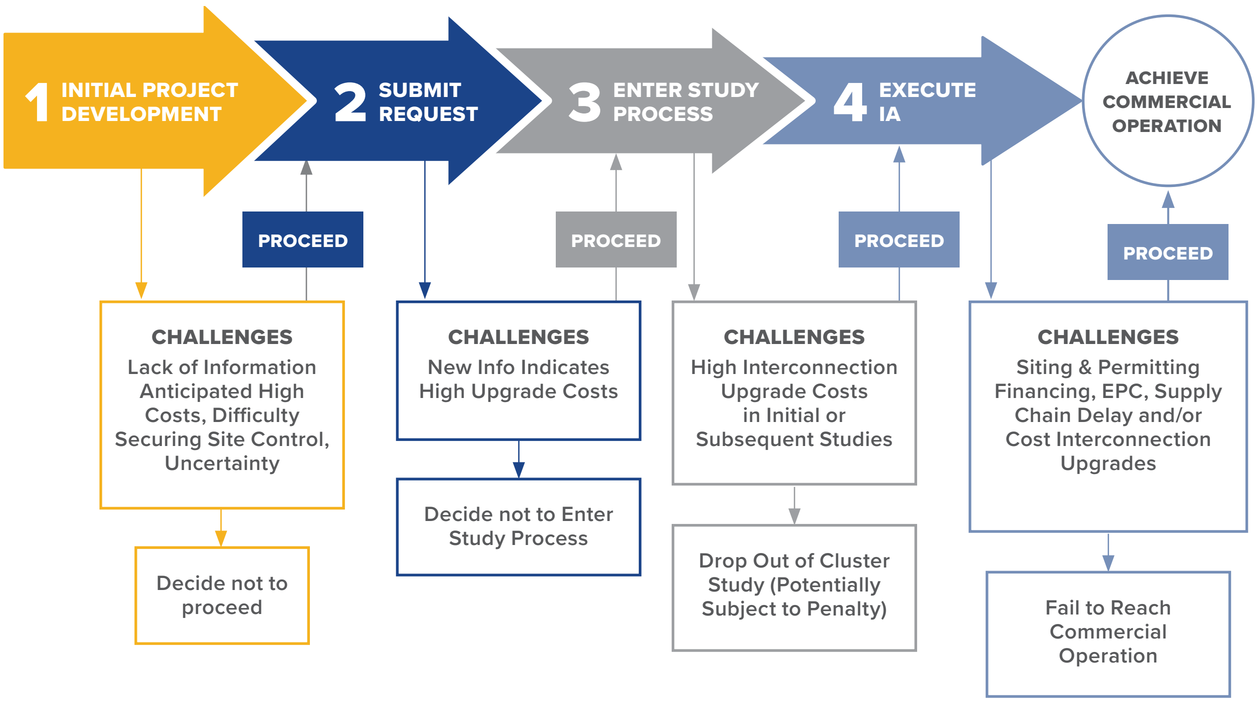
5. **Interconnection alternatives.** There are two key categories of alternatives to manage required levels of network upgrades: (1) the interconnection customer may elect an alternative level of transmission service; or (2) the Region or transmission provider may offer operational solutions or lower-cost (potentially temporary) solutions to transmission limitations. Interconnection alternatives are discussed further below.

6. **Affected system study process.** In addition to interconnection studies by the host transmission provider, projects are often studied by adjacent transmission providers believed to be potentially affected systems. These studies may be initiated after the interconnection customer receives a generator interconnection agreement from the host transmission provider.

7. **Commercial operation.** After the project itself, interconnection facilities, and any required network upgrades are built, the transmission provider and, where applicable, the Region authorize the project to begin commercial operation and deliver power to end-use customers.

These steps are illustrated in Figure 1.

FIGURE 1 | The Generation Interconnection Process[6]



Throughout this report, the term "Regions" applies to the seven regional transmission system operators graded in the scorecard and also considers the performance of the transmission providers that are members of those Regions. Similarly, the term "interconnection customer" refers to a generic interconnection customer or, when attribution is implied, to the 12 generation developers and engineering firms that participated in interviews for this Scorecard.

Interconnection alternatives: ERIS vs NRIS

One important distinction in the level of interconnection service is between projects classified as ERIS or NRIS. **Energy Resource Interconnection Service (ERIS)** is an interconnection service that allows delivery of electric generation using the existing capacity of the transmission system on an as-available basis. **Network Resource Interconnection Service (NRIS)** is an interconnection service that allows integration of all or a portion of a generating facility with transmission capacity to serve native load customers during hours with high grid stress. Terminology may vary across systems as there are other similar interconnection service level classifications in use. For simplicity, this report uses the terms ERIS and NRIS to represent different levels of interconnection service that are meaningful in an interconnection study.

6 Advanced Energy United, *Moving Through the Interconnection Queue: How a Project Gets Built—or Doesn't (2023).*

Most generators interconnect using NRIS. The more stringent NRIS study requirements are designed to assure customers who receive power from NRIS projects that sufficient transmission capacity exists to deliver power in the most severe grid conditions.[7] In some Regions, NRIS qualifies a resource to participate in the capacity market and receive preferential curtailment treatment during emergency conditions. The study and upgrade requirements associated with NRIS applications are often summarized as "invest and connect."

For interconnection customers who wish to bypass the stringent study requirements for NRIS, ERIS study requirements do not require deliverability. In exchange for the less stringent study requirements, interconnection customers who select ERIS are ineligible for capacity compensation and are curtailed before NRIS projects during emergency conditions, which results in relatively lower project revenues as compared to NRIS.

For example, one technical difference between ERIS and NRIS projects is the use of **distribution factor (DFAX)**. During an interconnection study of a project, the DFAX is calculated to measure the relative change (or sensitivity) of power flows on the transmission system expected to result from the project under study conditions. Regions and transmission providers set DFAX thresholds for purposes that include assignment of cost responsibility for network upgrades identified on a specific transmission asset (e.g., a transmission line or a substation). A lower DFAX threshold generally increases the probability that a project will be assigned cost responsibility for a wider scope of network upgrades. DFAX criteria may be used by the Regions in evaluating unaddressed reliability issues, cost allocation with respect to similarly queued projects, and real-time congestion affecting participants in organized energy markets.[8]

7 FERC Order 2003, para. 755.

8 MISO, *Background and Overview of Distribution Factor (DFAX)*, presentation to Interconnection Process Working Group and Planning Subcommittee (July 20, 2022).

Interconnection alternatives: "connect and manage"

Unlike the other Regions, ERCOT's interconnection process is often referred to as "connect and manage."[9] The concept is similar to ERIS in that projects are not required to meet the study and upgrade requirements to meet network transmission reliability planning standards. The resulting grid congestion is managed using economic curtailment and congestion pricing.[10]

Interconnection alternatives: Lower cost practices and technologies

In addition to alternative levels of transmission service, interconnection agreements may provide for alternatives to costly network upgrades such as operational practices, alone or in combination with lower-cost investments. One technical term used to describe such an operational practice is a **remedial action scheme (RAS)**. A RAS is an operational practice designed to automatically take corrective actions, such as curtailments, when predetermined system conditions are detected in order to maintain system stability, system voltage, and other system reliability concerns.[11]

Another key term used to describe alternatives to network upgrades is **grid enhancing technologies (GETs)**. GETs are hardware and/or software solutions that dynamically increase the capacity, efficiency, reliability, or safety of existing power lines, faster and at lower cost than traditional grid buildout.[12]

9 Tyler H. Norris, Beyond FERC Order 2023: Considerations on Deep Interconnection Reform, Duke University Nicholas Institute for Energy, Environment and Sustainability (August 2023).

10 In theory, the pricing information is used to identify future transmission system upgrades, but as discussed in Section 5.6, ERCOT's transmission planning is criticized for failing to address these economic upgrades.

11 NERC, "Remedial Action Scheme" Definition Development, Project 2010-05.2 (June 2014), p. 3.

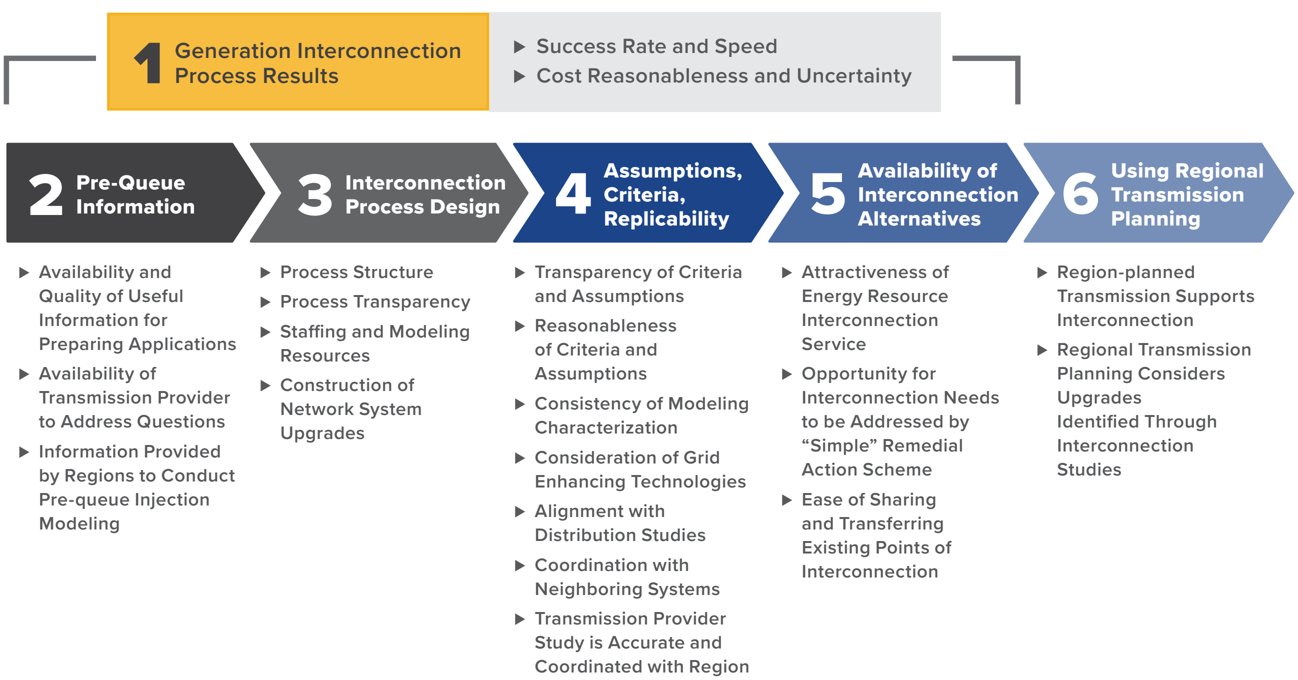
12 T. Bruce Tsuchida et al., *Building a Better Grid: How Grid-Enhancing Technologies Complement Transmission Buildouts*, Brattle Group for WATT Coalition (April 2023).

3 APPROACH TO DEVELOPING THE SCORECARD

3.1. Scorecard Categories and Metrics

As illustrated in Figure 2, the Scorecard is broken down into six grading categories, and the grades themselves are shown in Table 1. Each of these grading categories includes several "metrics," which are qualitative or quantitative topics that informed each category's grade. The evidence used for grading is discussed in Section 3.2, and an explanation of key terminology used throughout the Scorecard is in Section 2.

FIGURE 2 | Generator Interconnection Scorecard Categories



The first grading category covers the results of the generator interconnection process, specifically the timeline for interconnection and the costs assessed to upgrade grid facilities to enable the interconnection. Support for these grades can be found in Section 5.1.

The next four grading categories, discussed in Sections 5.2 through 5.5, reflect key aspects of the interconnection process that drive the results in the first grading category. If generator interconnection were simple, it might be possible to grade based on the results alone, but the complexity of the process drives many important outcomes that are not captured by the timelines and costs experienced by projects in the interconnection queues.

Finally, the sixth grading category, discussed in Section 5.6, assesses the quality of proactive regional transmission planning and its ability to facilitate generator interconnection. As mentioned above, for the regional planning category grade, the grade considers activities that are *underway* to upgrade the transmission system proactively, even if those upgrades have not yet had a direct impact on the generator interconnection process.

3.2. Evidence Relied on for Scoring Interconnection Processes

To develop the Scorecard, the project team reviewed publicly available data on the successes and challenges facing the generator interconnection processes across the country. As many of the questions studied in the Scorecard are qualitative and require knowledge and perspective of the technical experts at firms that directly experience the generation process, the project team also conducted interviews with interconnection experts in interconnection customer organizations.

The Scorecard grades rely primarily on two types of evidence. First, the team interviewed 12 generation developers and engineering firms. Interview participants are provided anonymity; citations to each interview use a two-letter code. The interview evidence was the most heavily weighted evidence in every scorecard category except interconnection process results (Section 5.1). In a few instances, published work by interconnection customers is cited alongside interview evidence and given comparable consideration.

Second, the team relied on Lawrence Berkeley National Laboratory's (LBNL) *Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection as of the End of 2022* and related data on generation interconnection costs.[13] LBNL supplied the project team with the data used for much of its analysis. This scorecard relies directly on that report and conducts original analysis of the data assembled by LBNL. These data are occasionally supplemented by data obtained directly from the Regions.

In addition to those two primary sources of evidence, the scorecard also relies upon other published works, as cited, and the project team's professional experience.

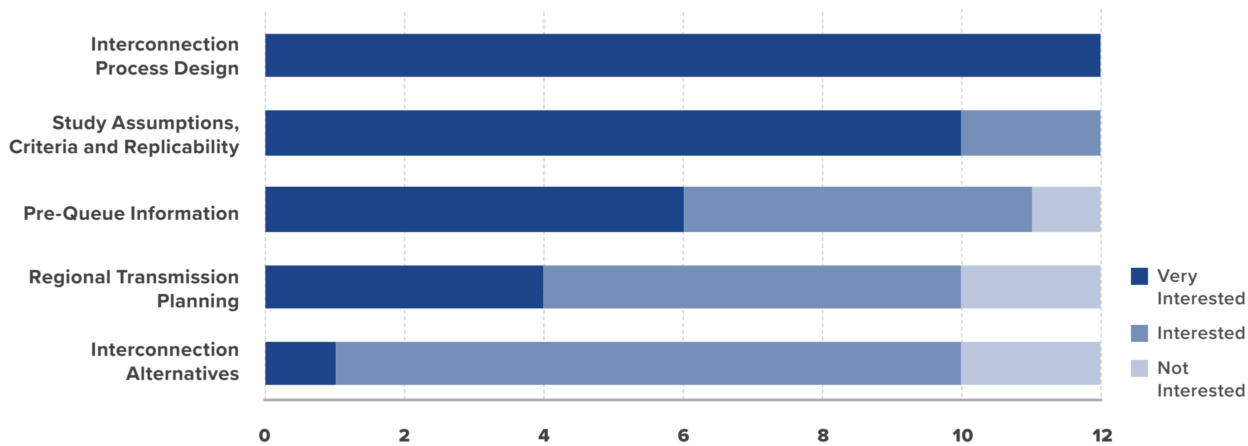
As discussed throughout this report, the interviews with 12 generation developers and engineering firms had a substantial impact on the scoring in each section. In addition, when aggregating the six category grades into a final overall grade for each Region, the project team took into consideration the relative importance expressed by interconnection customers for the six scorecard categories.

We gave the highest weight to the interconnection results grade because it reflects the outcome of the entire interconnection process, and because it considered both interview evidence and various data sources for corroboration.

13 Joseph Rand et al., *Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection as of the End of 2022* (April 2023), Lawrence Berkeley National Laboratory; and Joachim Seel et al., *Generator Interconnection Costs to the Transmission System – Summary Briefing* (June 2023), Lawrence Berkeley National Laboratory. Findings from *Queued Up* and the datasets from both reports are referenced henceforth as: LBNL, *Queued Up*.

The other five categories were weighted based on the interconnection customers' assessment of the relative importance of the five categories, as shown in Figure 3.[14] Interconnection customers gave the highest weight to the interconnection process and study assumptions/criteria/replicability. Pre-queue information and regional transmission planning got the next highest weighting, with interconnection alternatives weighted least. It should be noted that this weighting reflects interconnection customers' prior experience with opportunities to move projects forward from concept to commercial operation, and that it may not reflect the weighting that would be applied to an ideal interconnection process.

FIGURE 3 | **Interconnection Customer Assessment of Relative Importance for Five Scorecard Categories**



14 Interconnection customers were asked to indicate which categories they were interested in discussing during an interview. They were not asked to rank their interest in the first category, interconnection process results, because it is assumed that all parties would rank results as the greatest interest.

4 | GENERATOR INTERCONNECTION SCORECARD RESULTS

The Scorecard confirms the widespread recognition, including by FERC and the Regions, that the generator interconnection process is not working effectively and efficiently to allow new generation and storage resources access to the transmission network. Physical need for new resources is being driven by A) growing demand, due principally to new large loads, electrification of the building and transportation sectors, climate trends affecting weather-sensitive end uses of electricity such as building heating and cooling and B) planned generator retirements. The market is also responding to low costs for renewable energy, driven by innovation and federal subsidies, and state climate policies that set requirements for cleaner generation. Developers of new resources have requested generator interconnection for many projects, placing them in queues to be studied, resulting in the identification and construction of transmission facility upgrades. As is widely recognized, and this Scorecard confirms, the progress towards completing those interconnections is agonizingly slow and puts system reliability at risk.

As shown in Table 1, ERCOT and CAISO generator interconnection processes score the best, each receiving a B, but for different reasons. ERCOT received high scores for the quantity of resources that completed its interconnection process at a reasonable cost, but the lack of proactive regional transmission planning to upgrade its transmission system is a major impediment to development of new generation resources.

TABLE 1 | Generator Interconnection Scorecard Grades

	CAISO	ERCOT	ISO-NE	MISO	NYISO	PJM	SPP
Interconnection Process Results	B-	A	C	C	D	D	C-
Pre-queue Information	C+	C	D	C+	C	C	C-
Interconnection Study Process Design	B	A-	C-	D+	B-	F	D
Study Assumptions, Criteria, Replicability	A	A+	C+	D	C+	F	C
Usefulness of Interconnection Alternatives	B+	B	D	B-	D	D	B
Using Regional Transmission Planning	A-	D	D	B	C+	D+	C+
Overall grade	B	B	D+	C-	C-	D-	C-

In contrast, CAISO gets high marks for its proactive upgrades to its transmission system, but is rated lower than ERCOT for its overall interconnection process results due to recent delays in completing interconnection studies and agreements and constructing the necessary grid facilities.

The other five Regions received much lower overall grades with MISO, NYISO, and SPP each receiving a C-, ISO-NE receiving a D+, and PJM a D- as each suffers from its own particular set of maladies. While we acknowledge reforms are underway in each of the Regions, these low scores highlight the need for significant improvement, almost certainly beyond the scope of currently contemplated reforms. Because generator interconnection is a process, problems in any one part of the process can negatively impact the overall result. Broad, comprehensive reforms are essential to effective and efficient generator interconnection.

The generally poor overall grades that the current interconnection processes received are not surprising in the context of the increasing demands to interconnect new resources and deal with climate trends that are changing the timing, location, and severity of grid stress events. The Scorecard documents large differences across the Regions in specific categories that we have evaluated and received feedback on through the interviews. It shows that some of the Regions have elements of the interconnection process that are superior to those of most others. This provides pointers to potential "best practices" that Regions can use to learn from available experience and make more rapid improvements, as highlighted in Table 2.

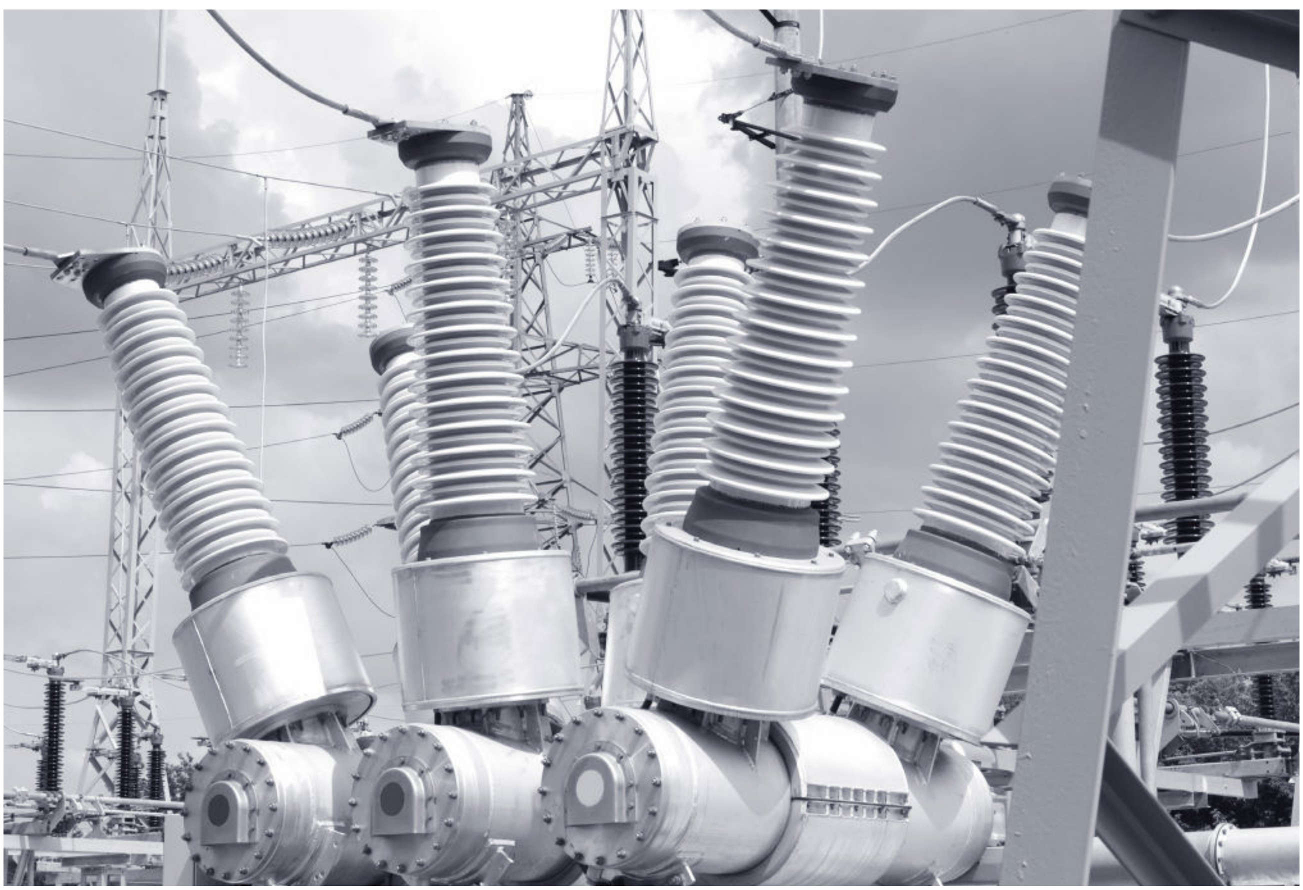


TABLE 2 | Key Drivers of Scorecard Overall Grades

Region	Grade	Key Drivers of Overall Grade
CAISO	B	CAISO gets strong marks for its high rates of studying resources, proactive upgrades to its transmission system, transparency, and cost sharing approach. CAISO's use of mitigation strategies to bring projects into operation until upgrades are constructed is also appreciated by interconnection customers. However, recent delays in interconnection study results have made it more difficult to complete CAISO's queue.
ERCOT	B	ERCOT gets high marks for processing a high volume of resources on a reasonable timeline and at reasonable costs. However, the lack of proactive regional transmission planning to address system constraints and resulting high levels of generator curtailment is a major impediment to development and deployment of new generation resources.
ISO-NE	D+	ISO-NE has a relatively low interconnection volume. Portions of its system are highly constrained (including Maine and in southeast Massachusetts), making it likely that projects will trigger significant system upgrade costs. Those upgrades, as well as planned transmission expansions, are difficult to build, making it difficult to bring projects online. Another criticism is the unique requirement for a high-cost model with the initial application.
MISO	C-	MISO's strongest point is its recent commitment to transmission expansion both within its system and in coordination with SPP along the seams of the two systems. However, its gap in planning studies has recently left the system with limited available capacity. Another positive is the availability of interconnection alternatives permitted outside of queue order. MISO's interconnection process is considered unreliable and slow with unpredictable cost outcomes. An additional concern includes recent changes to MISO's interconnection business practices to raise impact criteria for new projects.
NYISO	C-	NYISO gets its highest recognition for design of its interconnection process, with mostly reasonable study assumptions and criteria. However, the process has not produced compelling results, with long timelines and unpredictable costs that come late in the process. NYISO's use of regional transmission planning to expand opportunities for new generation resources has some promise but is not yet delivering substantial benefits. The availability of interconnection alternatives in NYISO is more limited than in other Regions.
PJM	D-	There are few bright spots for generator interconnection in PJM. Overall, it appears that PJM stuck with a sub-par serial process too long and its transition to a cluster process has frozen opportunities for new projects. In addition, PJM has not planned its system to create headroom for new resources, other than its recent process concerning NJ offshore wind. PJM receives a better score than other Regions on its responsiveness to questions.
SPP	C-	SPP also scores well for its coordination with MISO, but its current transmission planning process lacks a focus on creating opportunities for new generators. Its process operates closer to official timelines than some other Regions, but the resulting studies are often compromised by frequent restudy and errors that make the results undependable. While it is difficult to get interconnection alternatives considered in most Regions, SPP has 11 GW of operational ERIS resources (with another 26 GW in its queue)—yet interconnection customers indicated that scale of ERIS is creating challenges for recent interconnection applications.

5 SCORECARD DETAILED RESULTS AND DISCUSSION

The following sections provide details on each of the interconnection process metrics evaluated in the Scorecard.

5.1. Interconnection Process Results

The grades for interconnection process results consider six factors, as shown in Table 3. Two factors are the perspective of interconnection customers on timeline and cost. As discussed below, interconnection customers are more concerned about the uncertainty of the timeline (particularly as triggered by affected system studies) than by differences in the overall time to complete studies. Similarly, interconnection customers were more concerned about cost uncertainty than overall costs.

The remaining four factors are derived from LBNL's *Queued Up* report (particularly analysis of the underlying data provided by LBNL). These factors include speed and certainty (Figures 5 and 6), agreements signed (Figure 4, Table 4), average costs (Table 5), and cost certainty (Table 6).

Interconnection Process Results Metrics

1. Success rate
- Capacity (MW) of signed agreements relative to Region peak demand (GW) and capacity submitted

2. Speed
- Total time in queue
- Predictability and consistency of timelines

3. Cost reasonableness
- Cost per kW
- Cost variation by transmission provider

4. Cost certainty
- Project-specific changes in estimated network upgrade cost assignment from one study stage of queue to next
- Consistency of Regions' cost estimates with transmission provider cost estimates

An "ideal" grading system for interconnection process results would consider each of the four metrics, as shown in the sidebar. However, neither the Regions nor the interconnection customers have all the information required to complete an "ideal" evaluation of the results of the interconnection process. As a result, the overall grade for this category is a subjective weighting of the six components shown in Table 3, where the review team placed greater emphasis on certainty and consistency rather than the average timeline or average cost of completing the interconnection process.

TABLE 3 | Interconnection Process Results Grades

	Interconnection Customers[15]		LBNL Data[16]				
	Speed and Certainty Section 5.1.2	**Cost Certainty** Section 5.1.4	**Speed and Certainty** Figures 5 and 6	**Agreements Executed[17]** Figure 4, Table 4	**Average Costs** Table 5	**Cost Certainty[18]** Table 6	**Overall Category Grades**
CAISO	C	B	C	B	n/a	n/a	B-
ERCOT	A-	A-	A	A	A	A	A
ISO-NE	B	C	B-	D+	D	B	C
MISO	D	C	C+	C	D	F	C
NYISO	D	C	C-	D	F	D	D
PJM	F	C	D+	D	B	C	D
SPP	C	D	C+	D-	B	B	C-

5.1.1. Speed: Length and predictability of study and network upgrade process

Affected System Studies

Overall, the biggest driver of the difference in interconnection customer ratings of the timeline is affected system studies. An affected system study examines system impacts to adjacent and neighboring systems from projects queued to a host system. These studies are performed under separate timelines and frequently employ different assumptions and modeling methods between the host and affected system transmission provider. In interviews, interconnection customers identified the most severe affected system study risks to projects in the MISO, PJM, and SPP Regions, as well as in some non-RTO/ISO transmission provider territories. Affected system studies are a substantial cause of uncertainty in getting the queue process completed, with new costs and delays being imposed even at the point that a project is about to go into commercial operation. Affected system studies in MISO, PJM, and SPP entail significant electric grid interactions across their borders. This makes the coordination and sequencing of affected system studies essential to the queue process, particularly in the case of restudies.

15 See Appendix (Section 5.2) for interconnection customer assessments.

16 Analysis of LBNL, *Queued Up* dataset.

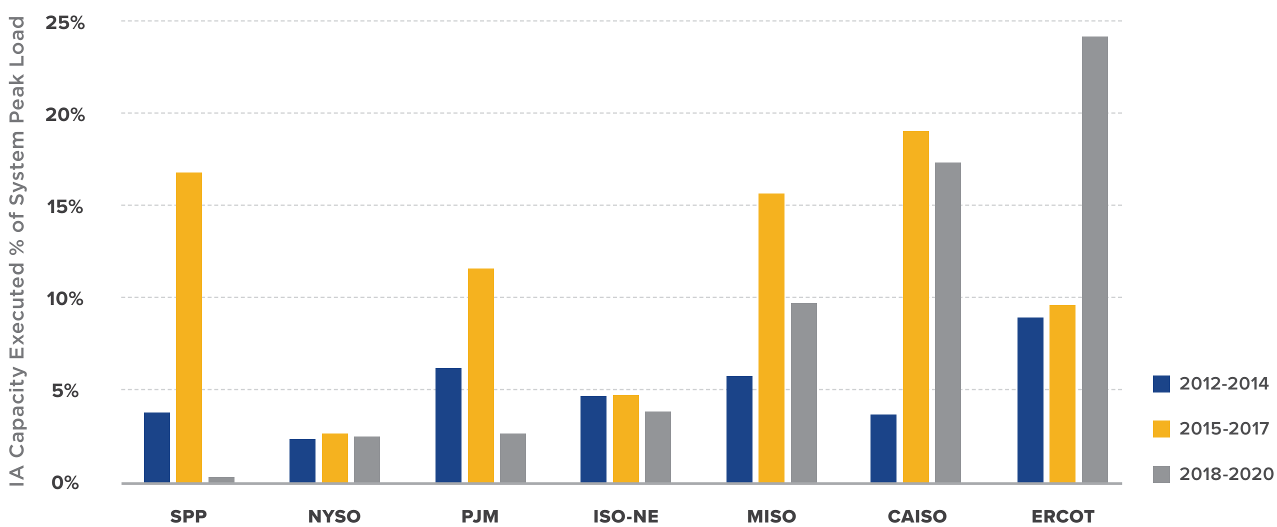
17 These grades are aligned with those in the ACEG report. Americans for a Clean Energy Grid (ACEG), *Transmission Planning and Development Regional Report Card* (June 2023), Table 19, p. 64.

18 These grades only consider cost certainty from one transmission provider to another within a Region, which is only one source of variation. The interconnection customer perspective on cost certainty is given more weight in this subjective grading.

Agreements Signed

ERCOT's relatively fast process also helped it take the lead in the overall rate of executing interconnection agreements. Across the seven Regions, the average rate of executing interconnection agreements submitted in 2018-2020 is about 9% of system peak load. ERCOT and CAISO are the clear leaders, with agreements representing 24% and 17% of their respective system peak loads in 2018-20, as shown in Figure 4.[19] Notably, the rate of interconnection agreements in SPP, PJM, and MISO decreased significantly from 2015-2017 to 2018-2020. All three markets had previously achieved interconnection agreement rates similar to CAISO and higher than ERCOT in 2015-2017, but their processes have been slowed by the significant increase in requests and are expected to remain low for projects that have entered since 2020. Rates of interconnection agreements in NYISO and ISO-NE have remained consistently below 5% of their system peaks over the last decade.

FIGURE 4 | **Interconnection Agreements Executed Through 2022 for Interconnection Requests Submitted from 2012-2020**[20]



It is particularly impressive that ERCOT has increased execution of interconnection agreements (Figure 4) while also maintaining a leading interconnection completion rate, as shown in Table 4. Over 40% of capacity in queue submissions to ERCOT in the 2012-2020 time period were completed and operational by 2022. (Projects not completed and operational may still be active in the queue, suspended, or withdrawn.) For projects submitted in 2018-2020, the completion rates for four Regions (ISO-NE, NYISO, PJM, and SPP) dropped to less than 10%, because of high queue submissions and slow progress in completing the study process. MISO has recently been able to process the second highest amount of capacity relative to the queue at 28%. Across the entire period, NYISO has the lowest completion rate.

19 Data in Figure 6 and Table 4 are presented in 3-year increments to smooth out less meaningful year-to-year variations and simplify the data.
20 Analysis of LBNL, *Queued Up* dataset.

TABLE 4 | Interconnection Agreements Executed Through 2022 and Completion Rates[21]

	Interconnection Agreements Executed Through 2022 (MW)			Completion Rates: Executed Agreements as Percent of Queue Submissions		
Queue Years	**2012-2014**	**2015-2017**	**2018-2020**	**2012-2014**	**2015-2017**	**2018-2020**
CAISO	4,943	27,113	23,849	14.8 %	38.0 %	15.2 %
ERCOT	17,885	19,864	52,740	41.3 %	45.4 %	42.6 %
ISO-NE	3,795	3,511	2,780	37.3 %	20.5 %	9.5 %
MISO	18,502	54,731	34,809	37.5 %	63.2 %	28.3 %
NYISO	2,219	2,393	2,248	33.8 %	16.6 %	3.5 %
PJM	28,989	50,734	11,771	48.0 %	46.0 %	6.3 %
SPP	5,600	24,863	340	38.7 %	40.1 %	0.9 %
All Regions	81,932	183,208	128,538	5.6 %	12.6 %	8.7 %

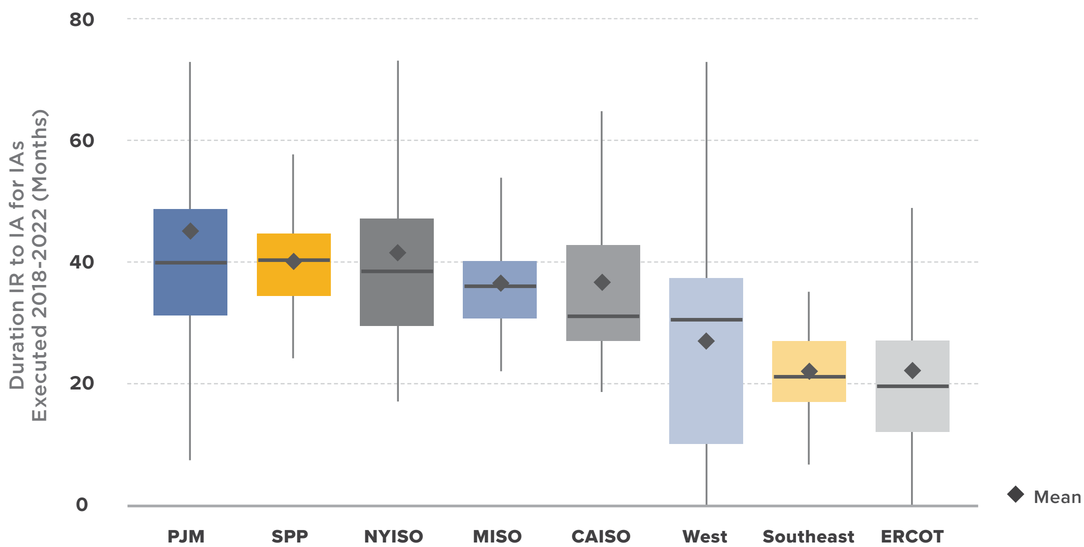
Of course, the objective of a good interconnection process is not to achieve a 100% completion rate. Projects that are submitted and later withdrawn reflect an exchange of information between the transmission provider and the interconnection customer about the prospects for a particular project. However, completion rates below 10% reflect a lack of sufficient upfront information and/or a deficient and burdensome process. The uncertainty and slowness of the interconnection process creates a perverse incentive for interconnection customers to submit even more proposals, which can create a negative feedback loop.

Length of Interconnection Process

LBNL's report evaluated the length and variability of the interconnection process for projects that completed the process between 2018 and 2022. As shown in Figure 5, while the mean study period length was around 40 months in each Region other than ERCOT, there was large variability in PJM, NYISO, and CAISO. These data are generally consistent with the observations given by interconnection customers, except that interconnection customers tended to give stronger weight to recent experiences with projects that remain in the queue. MISO is a particularly good example, where interconnection customers report a recent increase in uncertainty that is not reflected in the LBNL data.

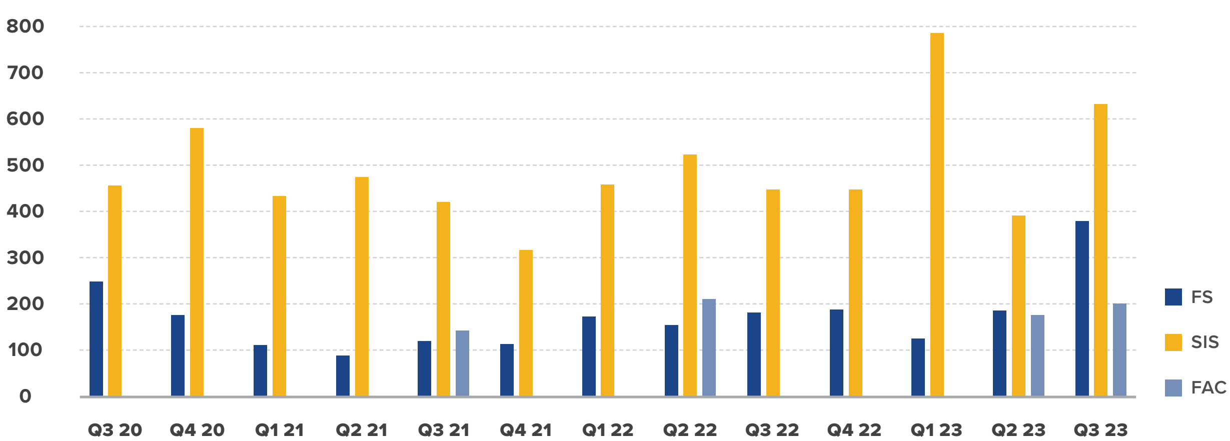
21 Analysis of LBNL, *Queued Up* dataset.

FIGURE 5 | LBNL Estimate of Interconnection Process for IAs Executed from 2018 to 2022[22]



ISO-NE appears to have a shorter timeline than the other Regions, although due to differing data sources a clear comparison is difficult. Since LBNL data are not available for ISO-NE (Figure 5), a recent ISO-NE timelines study is shown in Figure 6. This study suggests that ISO-NE timelines averaged around 25-30 months for interconnection agreements executed in 2020-2022. However, significantly longer timelines in 2023 suggest a high degree of variability in duration.

FIGURE 6 | ISO-NE Reported Study Durations, 2020-2023 (Number of Days from Study Agreement Execution to Study Delivery)[23]



22 LBNL, *Queued Up*, p. 27.

23 Figure reports duration of feasibility study (FS), system impact study (SIS), and facility study (FAC) for projects receiving an interconnection agreement in each quarter. ISO-NE, *Interconnection Study Metrics Third Quarter, 2023: Processing Time Exceedance Report (November 14, 2023), p. 5.*

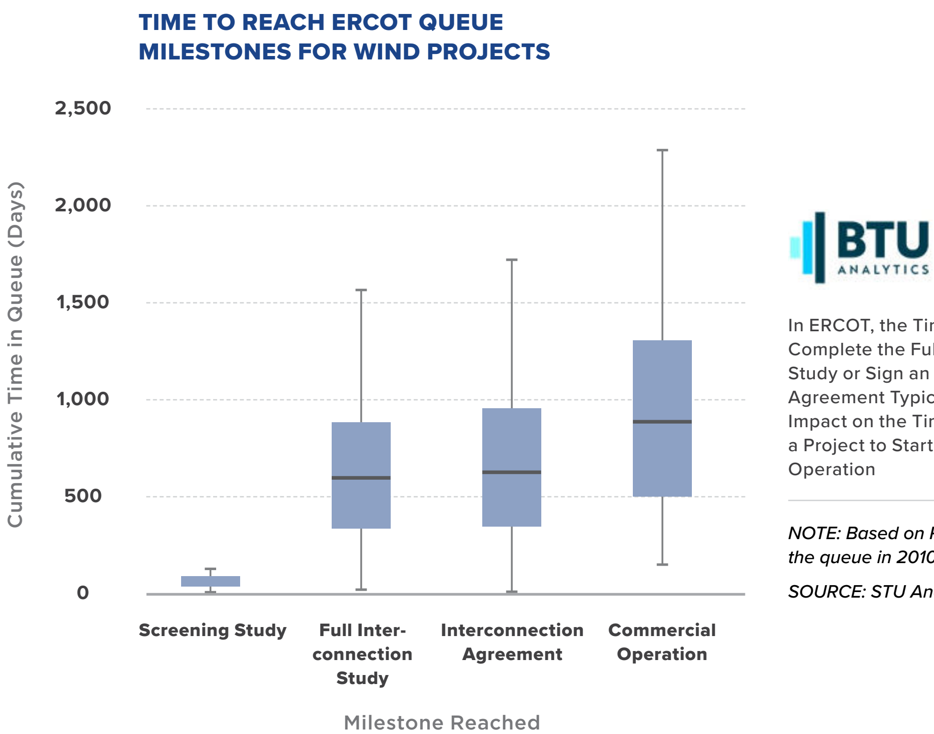
5.1.2. Regional assessments of interconnection speed

ERCOT: Simple process, reliable scheduling[24]

Interconnection applications in ERCOT have progressed more quickly and consistently than other Regions, with interconnection customers reporting that the current study process lasts about 2-3 years and LBNL's data (Figure 5) indicating that average projects take just two years.[25] These actual timelines are consistent with ERCOT's published timeline.[26] As long as the application is for a project that is ready, interconnection customers believe ERCOT is quick to advance the application. Several interconnection customers have also noted that they have experienced variation in the timing in ERCOT based on which transmission provider is completing the interconnection studies, since ERCOT does not complete the studies themselves.

After receiving an interconnection agreement, projects in ERCOT are able to reach commercial operation in about a year, as shown in Figure 7. However, it appears that some projects may have required two years or more to reach commercial operation.

FIGURE 7 | ERCOT Interconnection Process Timeline Results[27]



In ERCOT, the Time Taken to Complete the Full Interconnection Study or Sign an Interconnection Agreement Typically has the Most Impact on the Time it Takes for a Project to Start Commercial Operation

NOTE: Based on Projects that Entered the queue in 2010 and Onward

SOURCE: STU Analytic' Power View

24 Interviews zb, zd, zf, zh, zm, zr. Aaron Vander Vorst and Adam Stern, *Plugging In: A Roadmap for Modernizing & Integrating Interconnection and Transmission Planning (October 2021), Enel Green Power Working Paper, p. 9*

25 One interconnection customer noted that transmission owners in ERCOT used to complete facility studies in less than half a year, but that has significantly increased.

26 ERCOT, *Resource Interconnection Handbook (March 1, 2023), Version 1.94, Appendix D, p. 48.*

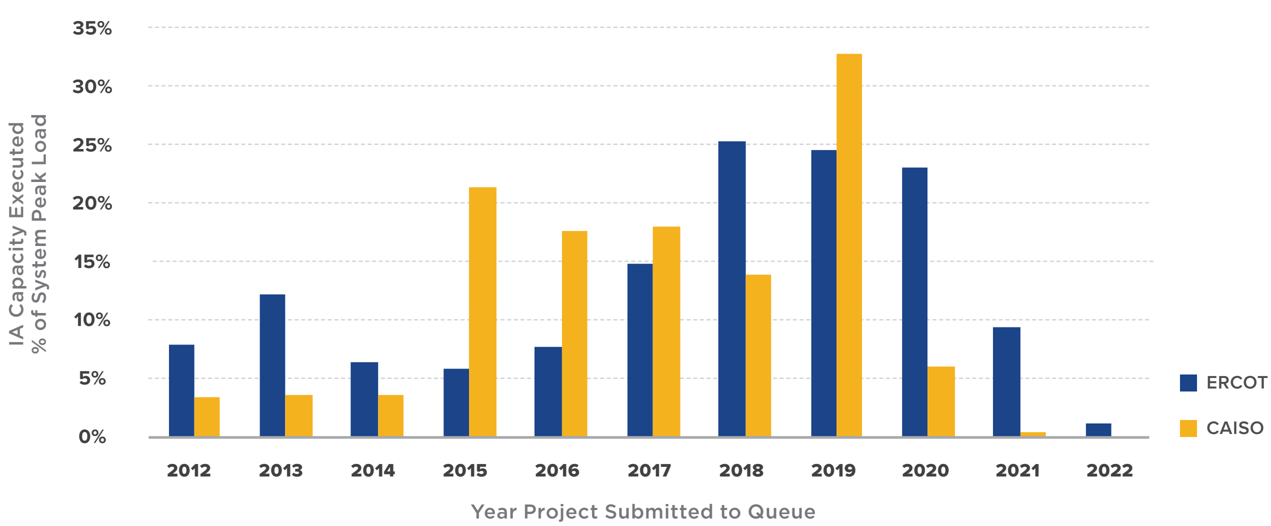
27 Trevor Fugita, Waiting in Line: Measuring Generation Queue Durations (June 15, 2021).

CAISO: Recent surge in projects has stalled a previously efficient process[28]

CAISO has been using clusters to process interconnection requests with roughly annual open windows, and is now on Cluster 15. Through Cluster 13 in 2020, interconnection customers report that CAISO kept to a timeline of around two years for processing project applications, with Phase I taking six months and Phase II taking one year. Even though this is longer than CAISO's official one-year timeline,[29] interconnection customers described CAISO's performance during this period as best-in-class, with effective communication on timeline delays.

However, when there was a massive increase in requests for Clusters 14 (opened in 2021) and 15 (2023), projects in CAISO have been extremely delayed in their progression through the study process. Delays are expected to be over three years for Cluster 14, the timeline for Cluster 15 is unclear, and new clusters are on hold subject to pending reforms. Evidence of these delays are illustrated in Figure 8, which shows that CAISO's interconnection capacity execution rate dropped for capacity that entered the queue in or after 2020 reflecting the slowdown for Cluster 14, while ERCOT maintained its pace in 2020 and completed its study of significant capacity that entered in 2021.

FIGURE 8 | CASIO Compared to ERCOT: Interconnection Agreements Executed Through 2022[30]



Because deliverability allocations are so important to load-serving entities as a part of their procurement requirements in CAISO (enabling the satisfaction of resource adequacy), interconnection customers are "parking" projects in the queue while waiting for an allocation. Until system upgrades go through, the queues are stalled.

28 Interviews zb, zk, zm, zn, zr.

29 Songzhe Zhu, *IR Application Generator Facility Data Form Overview (March 3, 2021), p. 22.*

30 Analysis of LBNL, *Queued Up* dataset.

One other positive on CAISO's process is that after the Phase II studies are complete, CAISO has annual restudies and deliverability allocations, which are not triggered by withdrawals.

ISO-NE: Location matters[31]

Timing in ISO-NE depends on the location of the interconnection, and the serial nature of the current process allows for wide variation in outcomes. Overall, the queue in ISO-NE is smaller and thus involves less schedule risk. Interconnection customers report that in some areas, projects can move through to completion in 2 years, which is consistent with ISO-NE's official timeline.[32]

However, interconnection customers noted that two areas in ISO-NE can take longer: southeast Massachusetts and Maine. In southeast Massachusetts, the offshore wind project cluster is impacting other projects due to uncertainty about timing or interconnection details. In Maine, the lack of available headroom on the existing system requires additional studies to be completed to identify the required upgrades. As a net exporting state, interconnections in Maine often trigger upgrades on the limited transmission facilities available for power exports.

A unique feature of ISO-NE's queue is the presence of "optional" process steps.[33] According to an interconnection customer it is common practice for projects to skip feasibility or facility steps and go directly to receiving a proposed interconnection agreement based on system impact study-level estimates. This is a voluntary way for projects to reduce study times.

MISO: Unreliable and slow study process[34]

Interconnection customers report that successful interconnection applications in MISO have progressed through the queue in 2-4 years, a figure confirmed by LBNL's data (Figure 5), but there are many delays, and schedule estimates provided by MISO are inaccurate. MISO's queue process is supposed to take just a year.[35] MISO's timeliness challenges have become particularly evident recently, as queue sizes have increased. While MISO used to share details with interconnection customers on the reasons for delays, over the past two years these updates have become less dependable. Then, once MISO releases model results, interconnection customers have 15 days to do their own modeling analysis to determine whether or not they will remain in the queue. This is challenging, especially because the interconnection customers have no reliable notice as to when that 15-day period will occur so they cannot plan for it and must respond quickly once provided the results.

Although MISO's recent study enhancements to limit system impact study duration are intended to reduce queue processing to 373 days, interconnection customers still anticipate that most projects will take 3 or more years to complete, especially in MISO-West.

---

31 Interviews zd, zk, zr.

32 Stojan Nikolov, *Interconnection Process (February 16, 2023), ISO-NE Webex Broadcast, pp. 8, 73.*

33 See: Stojan Nikolov, *Interconnection Process (February 16, 2023), ISO-NE Webex Broadcast, p. 8.*

34 Interviews zb, zf, zj, zm, zn, zr.

35 Sam Hipple, *MISO Interconnection Process: Overview, Innovations, Initiatives & Updates (December 5, 2023), EUCI Presentation; MISO, Generation Interconnection Business Practices Manual, BPM-015-r26 (August 2, 2023), p. 35.*

SPP: Backlog 5 years and growing, with no evidence that reforms are making a difference[36]

Successful interconnection applications in SPP have recently progressed through the queue very slowly. Both LBNL data (Figure 5) and interconnection customers indicate that projects take 2-4 years to move through the queue (one reports a just-signed agreement that took six years). This is considerably longer than SPP's official timeline, which estimates the process should take less than a year and a half.[37]

Today's backlog is five years and growing, with interconnection agreements in 2018-2020 having come to a virtual standstill (Figure 5). A positive note is that schedule estimates provided by SPP are relatively accurate, perhaps due to the adoption of automation.[38] Unfortunately, this schedule consistency is undermined by the quality of the studies. Several interconnection customers noted that they have received study results with significant errors, and that SPP provides slow responses to inquiries about those errors.

In addition to concerns about quality control, interconnection customers identified the dependency of each cluster's study results on the status of earlier clusters. With 4-5 clusters proceeding in parallel it is difficult to make commercial decisions for projects in the later clusters. This suggests that SPP's attempt to reduce the timelines by using overlapping (or parallel) clusters to speed up processing may not successfully reduce the backlog. Instead, this approach has simply increased the number of restudy cycles, which overall may just increase the queue processing time.

NYISO: Bogged down and not improving[39]

The last cluster ("class year") is reported as having required 18-24 months before the first study was completed, and projects that have been in the queue for 3 years do not currently appear close to completion. LBNL's findings (see Figure 5) indicate that NYISO projects usually take longer than 3.5 years to proceed through the queue. In contrast, NYISO aspires to a 1.6-year timeline in its proposed reform, with an additional three months for projects in the "transitional" cluster.[40]

Interconnection customers note that the iterative cost allocation process results in drop-outs at every study stage, which was viewed positively by interconnection customers. A change that was supposed to expedite the process through a more detailed study (at the risk of more required upgrades) did not result in quicker results.

---

36 Interviews zb, zf, zg, zj, zm.

37 SPP, *Generator Interconnection Business Guide and Practice (September 12, 2023), p. 8.*

38 SPP is collaborating with AWS and Pearl Street. See: William Driscoll, "Artificial Intelligence Could Speed Interconnection, Says Amazon Executive," *PV Magazine USA* (October 17, 2022).

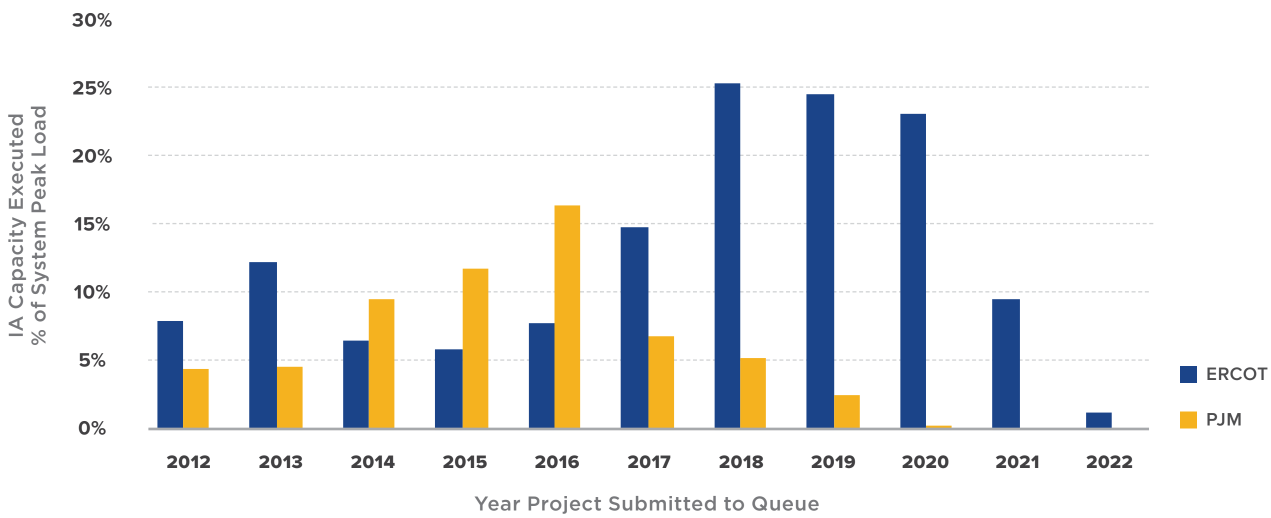
39 Interviews zk, zh.

40 Thinh Nguyen, *Interconnection Order No. 2023: Proposed Compliance Approach (December 1, 2023), NYISO Interconnection Issues Task Force p. 8. Note: A comparable graphic for NYISO's current process could not be located.*

PJM: Complete stop; Longest timelines, most uncertainty[41]

Interconnection customers with experience in multiple RTOs tended to be most critical of PJM's process timelines. As shown in Figure 9, PJM's interconnection capacity execution rate began to decline in 2017, as the gap between ERCOT and PJM began to grow.

FIGURE 9 | PJM Compared to ERCOT: Interconnection Agreements Executed Through 2022[42]



The most frustrated interconnection customers note that PJM's interconnection study process for new projects has come to a full stop, with the hope that projects from 2019 may complete the process six years later in 2025. One interconnection customer has ceased developing projects in PJM, and other interconnection customers are uncertain whether their projects are getting studied or not. One interconnection customer stated that PJM has "no regard for reasonableness and decorum when it comes to communicating deadlines." Even though PJM has developed new practices that should improve the process going forward, significant delays have been imposed on projects that have been transitioned to the cluster process so there is limited evidence currently about its effectiveness in completing the necessary studies.

Interconnection customers also critiqued PJM's now-replaced serial process. One interconnection customer described a project that received an interconnection agreement in the serial process in "just" 3.5 years – the customer was only able to get that agreement by purchasing and terminating projects that were ahead of the project in the serial process queue. LBNL's data validates their experience as the average PJM project has taken nearly four years to complete.[43]

41 Interviews zb, zf, zg, zh, zj, zm, zr.

42 Analysis of LBNL, *Queued Up* dataset.

43 PJM, *PJM Manual 14H: New Service Requests Cycle Process (July 26, 2023), p. 26.*

Another interconnection customer found some positive things to say about PJM, stating that its now-replaced serial process took 2-4 years. Even this most positive assessment indicates the process takes longer than the nearly two years estimated by PJM.[44] They noted that PJM could get an initial study out pretty quickly, albeit with results that were not reliable. Overall, however, the interconnection customer still described the process as very inefficient, with lots of time waiting for restudies to be completed, sometimes as many as 5-6 restudies.

Non-RTO/ISO transmission providers: Potentially fast, but depends on the utility[45]

While this report does not grade non-RTO/ISO transmission providers, several interview participants are active in those areas and compared those providers' interconnection timelines with those of the Regions. One interconnection customer indicates that projects can progress quickly in several non-RTO/ISO providers' processes if the project has been selected in a solicitation. Such projects tend not to linger or suspend progress. Another interconnection customer cites positive progression in Idaho Power's queue process, but the need to resolve several affected system impact studies associated with another request in Bonneville Power Authority's queue.

5.1.3. Interconnection Costs: Cost uncertainty a larger concern than total costs

Overall, interconnection customers express concern about interconnection cost *uncertainty* more so than overall costs. The Regions assign interconnection costs based on impact. The interconnection costs in many Regions tend to be volatile through the phases of the interconnection study process, such that the total interconnection costs are not known until the end of the multi-year process. A secondary concern with uncertainty is the challenge of marketing projects that are subject to dramatic cost swings where it is possible that upgrades increase by twofold and undermine project economics. Such unpredictability inhibits contracting and project success.

While it is not unusual for interconnection costs to be a relatively small portion of total costs, interconnection costs are significant enough that they do impact project viability. An analysis by Charles River Associates found that network upgrade costs on average represented less than 10% of total project costs in MISO.[46] Costs to interconnect are also increasing: as discussed below, as interconnection costs for projects in operation represent about 4% of total capital costs for solar and wind resources, and for projects with signed interconnection agreements (not yet in operation) interconnection cost estimates represent about 14% of total capital costs.

Significant swings in interconnection costs throughout the process can put projects at risk. An interconnection customer notes that with transmission upgrade costs trending up, those costs are a more important indicator of project viability than they have been in the past. Another interconnection customer explains that even in markets with high average costs, there can be good opportunities for development, citing CAISO and ISO-NE as examples.

44 PJM, *PJM Manual 14H: New Service Requests Cycle Process (July 26, 2023), p. 26.*

45 Interviews zd, zp.

46 Network upgrade costs as estimated in Phase 3 studies, excluding "TOIF & Affected Systems." Charles River Associates, MISO Interconnection Queue: M2, M3 and M4 Security Deposits and Return Procedures (August 26, 2023), presentation to MISO, p. 11.

Background on assignment of system upgrade costs to generator projects

Upgrade costs are assigned to new generation resources differently depending on whether the interconnection study uses a serial or cluster process. One approach is demonstrated by PJM's original serial process: upgrade costs were assigned based on the principle of "First to Cause." When the study process determines that a project requires a network upgrade, the project provider is responsible for 100% of the upgrade. Often, this upgrade will provide sufficient benefits so that later projects (those further back in the interconnection queue) will receive lower mitigation costs.

Depending on upgrade scope, the policy of First to Cause can render project economics unfeasible for a single project to undertake. If that project withdraws from the queue, this can trigger a dynamic that causes the upgrade costs to be reassigned to subsequent projects, potentially triggering a cascade of withdrawals and further reassignments. While reimbursement can occur between initial and subsequent projects on a limited basis, this cost allocation policy has stifled queue progress and new entry deployment.

PJM is changing to a cluster study process as a part of its recently approved queue reform, and FERC Order 2023 directs all transmission providers to do the same. Each project that is studied together with other projects in the cluster is assigned costs based on the percentage contribution of individual projects to a common upgrade. This sharing of upgrade costs enables larger transmission system facilities to be financed by the responsible cluster; this is referred to as a Shared Network Upgrade.

Upgrades funded by new generators can also benefit existing transmission system users. For example, in MISO interconnection customers are responsible for 90% of the cost of upgraded facilities with voltages of 345 kV and higher, with existing system users paying the remaining 10% of the cost.[47]

With some differences, cluster upgrade funding is now utilized in all Regions except CAISO and ERCOT. While generators pay upfront for interconnection costs in CAISO, project developers are reimbursed up to a capped level subject to their project receiving allocation of firm delivery rights on the system and entering a contract with a load serving entity. CAISO's repayment term is 5 years, with costs recovered from all transmission access customers.[48]

In ERCOT, interconnection customers pay very low interconnection costs, with projects' current responsibility limited to certain direct costs of connecting the generator to the transmission system. The remaining costs are paid by the transmission provider and passed through to retail customers.

In several Regions, projects with interconnection agreements are eligible to request long-term Financial Transmission Rights (FTRs) in return for funding network upgrades and creating incremental system capability. In SPP, the request for financial transmission rights occurs in the queue process.[49] While the value provided by FTRs is meant to offset market-based congestion, the specific FTR paths sought by interconnection customers are frequently unavailable or not feasible. This form of compensation is generally viewed to be suboptimal from a project finance perspective.

47 MISO is the only region that uses this approach for allocating the cost of high voltage network upgrades.

48 16 TAC §25.195(c). In cases where costs are high, ERCOT conducts further studies to examine the economic benefit of the upgrades, but any action would be at the discretion of the transmission provider. ERCOT, *ERCOT Planning Guide*, Section 5.2.3 (November 19, 2023).

49 This replaced SPP's former crediting system (termed "Z2") in which interconnection customer credits were dependent on usage of upgraded facilities.

Regional variation in costs and cost certainty

The average cost of interconnection for projects in operation across five of the seven Regions included in this scorecard is about $58 per kW, and $177.5 per kW for projects with signed interconnection agreements, as shown in Table 5, based on data from the LBNL *Queued Up* report. Interconnection costs for projects in operation represent about 4% of total capital costs for solar and wind resources, and for projects with signed interconnection agreements (not yet in operation) interconnection costs represent about 14% of total capital costs.[50] The costs analyzed in Table 5 include costs at the point of interconnection as well as costs for network services, comparing (a) currently active projects in the queue, (b) projects with interconnection agreements but not operating as of 2022 (but entering the queue in 2013 or later), and (c) operating projects placed in service from 2018-2022.

Available data vary by Region and are not available for CAISO or ERCOT. Interconnection customers reported that costs in CAISO are substantially higher than in other Regions due to the high cost of construction in CAISO. However, upgrade costs in CAISO are offset by refunds. ERCOT costs are presumed to be nearly zero because interconnection customers are only responsible for certain direct costs of connecting the generator to the transmission system.

TABLE 5 | Estimated Average Interconnection Cost, Projects Submitted to Queue 2012-2020 ($/kW)[51]

Region	Active Applications in Queue	Interconnection Agreement Signed	Project In Operation	Total
SPP	83.4	52.2	39.5	69.0
NYISO	129.3	104.1	130.7	124.0
PJM	290.8	32.0	25.7	184.5
MISO	258.2	322.9	80.7	223.8
ISO-NE	278.5	131.2	64.3	245.3
Average	$ 217.4	$ 177.5	$ 58.3	$ 174.6

Notes: Data for NYISO does not distinguish between interconnection agreements signed and projects in operation. For NYSIO, one 1,020 MW natural gas plant with interconnection costs of $329 / kW is excluded from the analysis as an outlier. Including this value significantly increases NYISO's average interconnection cost for completed projects.

There are several findings evident in Table 5 and related analyses:

- Interconnection costs for operational projects are substantially lower than forecast costs for active applications. Inflationary pressure related to supply chain constraints and increased project demand is surely a factor since operational project costs were established further back than the most recent study cost for an active application. Furthermore, it is likely that

50 Total capital costs for solar and wind are from NREL, 2023 Electricity Annual Technology Baseline, available at: https://atb.nrel.gov/electricity/2023/index.

51 Average is calculated on a nameplate capacity weighted basis. Analysis of LBNL, *Queued Up* dataset.

projects assigned high costs drop out, causing the reduction in average cost for those that are completed.

- In exploring possible drivers of cost variation across Regions, there were no significant factors apparent from the data. The only exception is a difference between interconnection costs for clean energy project costs and those for all energy projects shown in Table 5 for NYISO and ISO-NE. Operational clean energy projects (solar, wind, storage, and hybrid) cost over $175 per kW in those regions, compared to $131 per kW in NYISO and $64 per kW in ISO-NE across all projects.
- Considering the costs of projects with completed interconnection agreements, PJM and SPP stand out as having had lower costs. Costs in NYISO are higher.

However, these average costs mask significant variation in costs within the Regions. Table 6 compares the variation in the average cost to interconnect among transmission providers *within* each Region.[52] This analysis was suggested during interconnection customer interviews in which high variation in construction management and costs was frequently noted.

TABLE 6 Estimated Regional Standard Deviation of Interconnection Cost ($/kW) and Coefficient of Variation, Projects in Operation or with Completed Interconnection Agreements[53]

Region	Count of Transmission Providers	Standard Deviation ($/kW)	Coefficient of Variation
ISO-NE	6	$ 57.4	41 %
SPP	17	$ 21.6	45 %
PJM	20	$ 24.2	123 %
NYISO	8	$ 297.3	256 %
MISO	35	$ 422.2	425 %

Note: ISO-NE data are reported by state, not transmission provider.

As indicated by the coefficient of variation, some Regions have highly variable interconnection costs. While interconnection costs for completed projects in ISO-NE and SPP have been relatively consistent, there is much higher variation across transmission providers in NYISO and especially MISO.

One possible driver of cost uncertainty flagged by interconnection customers is that many Regions and non-RTO/ISO transmission providers use assumptions in their studies that do not reflect likely scenarios for grid operating conditions.

Interconnection customers also raised concerns with the cost uncertainty within the study process for each project, and the challenges this creates while completing the process. This is especially a problem in Regions with large queues that experience high withdrawal rates, as withdrawals of earlier projects in the queue can swing costs either up or down depending on the study outcomes.

52 In the case of ISO-NE, transmission provider data are unavailable so the ISO-NE standard deviation refers to variation across the six states.

53 Standard deviation is calculated on an unweighted basis across all transmission providers or, in the case of ISO-NE, states. Analysis of LBNL, *Queued Up* dataset.

Considering cost uncertainty, interconnection customers are most concerned about affected system studies, as discussed in Section 5.4.1 below, which also have detrimental impacts on timelines. Affected system studies affect interconnection customers in every Region, as well as those operating in utility service areas outside of the Regions. Interconnection customers provided the most specific concerns about affected system studies involving the MISO, PJM and SPP Regions. Affected system studies are a substantial cause of uncertainty in getting the process completed, with new costs or delays being imposed even at the point that a project is about to go into commercial operation.

5.1.4. Regional assessments of interconnection costs

ERCOT: Low interconnection costs come with high congestion and curtailment risk[54]

The ERCOT process only requires local facility upgrades, resulting in relatively low interconnection costs which are predictable and consistently applied. However, project output may be limited by Generic Transmission Constraints (GTCs) imposed by ERCOT on new projects as a reliability backstop. Projects are especially prone to curtailments caused by system outages. While the low cost of interconnection is a positive for interconnection customers, the relative lack of proactive transmission planning increases operating risk, which puts financial pressure on new entrants and long-term project owners. Interconnection customers cannot even volunteer to pay for upgrades because the transmission providers have to take projects to the Texas Public Utilities Commission for approval—this approval process puts cost in rate base and is not designed to accept participant contributions.

CAISO: Limited upgrades, transparent costs, yet "California expensive"[55]

Interconnection customers report that prior to Cluster 14 (2021), CAISO had relatively low interconnection costs for customers with transmission planning delivery, known as "Option A."[56] For projects with transmission planning delivery allocations, interconnection customers receive refunds of their network upgrade costs within 5 years. These refunds are made by the transmission providers, who recover those costs from load (end users of electricity) through CAISO's Transmission Access Charges.

CAISO is also described by interconnection customers as having a reputation for consistent and reliable costs. This consistency is reinforced by rules that require transmission providers to publish per-unit costs for network upgrades that are used in CAISO's interconnection studies. The Phase II study costs, as allocated to each project, provide the interconnection customer with a maximum cost responsibility for the interconnection agreement. This type of cost protection differs from other Regions, where upgrade estimates are prone to revision through further restudies. While annual reassessments do result in potentially significant variation in expected upgrade costs prior to signing an interconnection agreement, the reassessments do not often put progress towards interconnection at risk due to the cost cap.

---

54 Interviews zb, zg, zh, zm, zp; project team contribution.

55 Interviews zb, zh, zm, zp.

56 Option B is an interconnection request in which the Interconnection customer does not seek an allocation of transmission planning delivery capacity. CAISO, *Appendix 1 Interconnection Request, Version RIMS-IR-CLUSTER-V01 (March 2020), p. 15.*

CAISO's use of Remedial Action Schemes (RAS) helps reduce interconnection costs by identifying operational practices that avoid network upgrades and mitigates the need for re-study when other projects drop out. (See explanation of RAS in Section 2.)

However, it cannot be said that CAISO's costs are low or that cost certainty can be achieved when interconnection studies are stalled. Interconnection customers report that construction costs in CAISO are 2-3 times the cost of the same upgrade in different Regions. Beginning with Cluster 14, the large number of projects in the queue caused Phase I cost estimates that are much higher and unreliable. Nonetheless, because CAISO refunds network upgrade costs to the project developer, interconnection customers bear relatively little cost risk, despite the high construction costs.

Furthermore, once projects are approved for interconnection, many projects financially depend on also getting approved for firm delivery (deliverability) necessary for load serving entity procurement. This is a challenge in the current CAISO process that does not provide interconnection customers with a clear path to fund and obtain deliverability, as discussed further later in this report.

ISO-NE: Cost estimates are so uncertain that upgrades can trigger withdrawal from the queue[57]

ISO-NE provides expedited cost estimates, but they are uninformative because they provide an estimate of the total costs with a vague description such as "reconductoring of X line," with no breakdown by subcategories or specification of what violations are triggered. Furthermore, ISO-NE does not provide any standardized costing guidance. Considering these two issues, one interconnection customer stated that it was unable to assess the accuracy of ISO-NE's cost estimate and make business decisions. According to that interconnection customer, most interconnection customers withdraw projects that trigger a network upgrade because of the lack of confidence in the cost estimates. Furthermore, in ISO-NE, each transmission provider has its own standards and costs, with excessive flexibility for upgrade costs to exceed estimates. The transmission provider's timelines for upgrades are also uncertain, impacting the schedule for bringing a project to operating status.

MISO: Costly, especially for ERIS projects[58]

Due to the large queue size in MISO, recent interconnection cost estimates have increased dramatically. For example, MISO interconnection costs estimates doubled for projects entering the queue in 2020 relative to those entering in 2018.[59]

Cost assignments are also uncertain, as project withdrawals result in costs shifting around. In particular, costs have changed substantially as projects progress from Phase 1 to Phase 2 to Phase 3. According to analysis of the 2017-2020 queue clusters by Charles River Associates, upgrade costs dropped from $232/kW in Phase 1 results to $73/kW in Phase 3 results.[60]

---

57 Interview zk.

58 Interviews zb, zj, zm, zn, zp, zr; project team contribution.

59 Excluding projects that have withdrawn from the queue. Analysis of LBNL, *Queued Up* dataset..

60 Charles River Associates, *MISO Interconnection Queue: M2, M3 and M4 Security Deposits and Return Procedures (August 26, 2023), presentation to MISO, p. 9.*

So while the cost decrease from Phase 1 to Phase 3 is welcome, interconnection customers question whether the Phase 1 cost estimate provides useful information regarding whether or not to proceed with a project.

It is not only the project withdrawals that drive cost uncertainty in MISO. One interconnection customer described a project whose costs increased by 50% with no change in project scope. Interconnection customers report that high costs in early-phase studies were particularly a problem in MISO-West in the 2016 and 2017 queue clusters, but that problem diminished in the 2018-2020 queue clusters, while a similar high-cost issue emerged in MISO-South.[61]

Project interconnection customers also express concern that these upgrade costs are imposed on both energy-only (ERIS) projects and firm-delivery (NRIS) projects with little distinction in upgrade requirements between the two levels of service. This is further discussed in Section 5.5.

SPP: Swinging between insufficient and excessive upgrades[62]

Cost uncertainty in SPP is driven by an interconnection study approach that identifies excessive upgrades that result in project withdrawals and the need for re-study, much like MISO. Interconnection customers state that because the studies use assumptions that are unlikely to reflect actual operating scenarios, the resulting upgrade requirements and costs drive unnecessary project withdrawals for both ERIS and NRIS projects. The risk of cost reassessments during re-studies inhibits interconnection customers from moving forward with interconnection agreements.

On the other hand, a concern raised by some interconnection customers about SPP is that new projects brought online in the past few years have not had sufficient upgrades required, resulting in substantial congestion and curtailments. Curtailments in some cases adversely affect existing interconnection customers whose projects requested and paid for firm service prior to these new projects, expecting limited curtailment risks in return. This expectation in SPP contrasts with the ERCOT market where curtailment risk is expected in congested portions of the system due to the limited interconnection-related upgrades.

NYISO: Cost estimates come late, and interconnection customers cannot adjust in response to upgrades[63]

NYISO does not provide full upgrade costs until the end of the "class year" study process is complete. The information provided by NYISO lacks clarity, according to one interconnection customer, making it difficult to identify which upgrade requirements might be avoided if a project was converted from firm delivery (NRIS) to energy-only (ERIS).

61 See also: Andy Witmeier, *Generator Interconnection Queue Improvements (September 18, 2023), MISO Planning Advisory Committee (PAC) Special Meeting, p. 31.*

62 Interviews zb, zj, zm, zr.

63 Interview zk.

PJM: Costly interconnection outcomes[64]

In PJM's process, the costs to interconnect are uncertain, with final upgrades required to interconnect some projects requiring more costly network upgrades than predicted in earlier studies.[65] Interconnection customers said that PJM's new cluster study process so far does not yet inspire confidence in improvements in timeliness or certainty on costs. One interconnection customer commented that in some instances, transmission providers have found errors in PJM's studies that resulted in final costs being much higher than estimated through the interconnection process. Another stated that recently, interconnection cost estimates have become "astronomical," in their opinion due to the very large queue size. Their observation about costs is corroborated by data: As shown in Table 5, operational projects in PJM had relatively low costs of $26 per kW, while active projects in the queue have a much higher cost of $291 per kW, more than a tenfold increase.

Non-RTO/ISO transmission providers: More accurate cost estimates, but very costly in much of WECC[66]

Outside of the Regions, one interconnection customer pointed out that costs tend to be more accurate since there are fewer projects in many of those providers' queues. However, in WECC, projects tend to have higher upgrade costs than those in the eastern U.S. Even though there are the same number of upgrades, the higher voltages and longer spans drive up the costs.

5.2. Pre-Queue Information[67]

> **Pre-Queue Information Metrics**
>
> **5. Availability and quality of useful information for preparing applications**
>
> **6. Availability of transmission provider to address questions**
>
> **7. Sufficiency of information provided by Regions to conduct pre-queue injection modeling**

Overall, interconnection customers are dissatisfied with the pre-queue information provided by the Regions to support identification of suitable interconnection locations. For example, neither Regions nor the transmission providers facilitate access to necessary data about interconnection facilities such as available substation capacity. Interconnection customers would like to understand available "headroom" at each point of interconnection, but they are unable to obtain this information from either transmission providers or the Regions and he interconnection customers are not hopeful that proposed reforms will resolve these challenges. As a result, interconnection customers expect that they will continue to need to enter the queue to gain useful information about constraints on interconnecting at various points on the transmission system.

64 Interviews zb, zd, zh, zm, zr.

65 In a serial process, high-cost network upgrades may be uneconomic for interconnection customers, resulting in these costs being passed from earlier to later queued projects as projects drop out due to the cost. This cascading of cost through a serial queue undermines certainty and decision making by interconnection customers.

66 Interview zp.

67 Interviews zd, zf, zg, zh, zj, zk, zm, zn, zr.

The limited value of the available pre-queue information is compounded by poor responsiveness by the Regions' staff to ad hoc questions. Only MISO was considered better than the rest, and SPP was singled out for particular criticism on its refusal to provide key helpful information.

TABLE 7 | Pre-Queue Information Grades

	Pre-Queue Information
CAISO	C+
ERCOT	C
ISO-NE	D
MISO	C+
NYISO	C
PJM	C
SPP	C-

Even though interconnection customers are dissatisfied with the information needed to support locating optimal interconnection points, they are relatively satisfied with the technical information needed to prepare a viable interconnection application. For PJM, MISO, NYISO, SPP, and ERCOT, the quality of pre-queue injection analysis information is sufficient to provide some information about the viability of an application. However, they are generally dissatisfied with non-RTO/ISO transmission providers who do not provide this information. An interconnection customer noted difficulty in replicating or pre-screening ISO-NE's process for modeling deliverability.

While the requirement to make heat maps available is a much-noted feature of FERC Order 2023, interconnection customers are generally not hopeful that heat maps will aid the interconnection process because they expect that there will be too many limitations to their usefulness. Currently, with many Regions having multiple cluster cycles in process at a given time, the high uncertainty driven by future decisions on hundreds of queued projects makes it nearly impossible to get actionable information prior to submitting a request. As one interconnection customer noted, unless the heat maps provide "contractable" quality information, the heat maps will have limited impact on discouraging non-ready projects from entering the queue at impractical locations. Providing "contractable" information in a heat map may be almost impossible given the large queue volumes.[68]

Some interconnection customers are looking forward to heat maps being made available by non-RTO/ISO transmission providers, because those transmission providers provide virtually no pre-queue information at all, and the heat maps may provide some useful information. Otherwise, interconnection customers were uniformly skeptical that heat maps could provide useful information for making informed pre-queue interconnection application decisions.

68 This concern also applies to the usefulness of model data for injection studies.

Interconnection customers also expressed general concern related to delays in updating models, and noted inconsistencies across the various Regions. One interconnection customer felt that taking six months to update a model after a queue window closes is too long and limits its usefulness. Another noted that the Regions should coordinate and select a single software approach for modeling generation. Ideally, interconnection customers would like to have “ballpark” estimates of costs to interconnect, but this may be a long-term goal given the status of the Regions’ interconnection queues.

Interconnection customers mentioned two specific types of information about substations that they find challenging to obtain from the Regions: 1) whether a substation has an open terminal bay for new projects (or whether new terminals must be constructed) and 2) whether a substation has an existing fiber connection. Both terminals and new fiber connections are costly upgrades that can substantially affect the feasibility of a project. Interconnection customers feel strongly that the Regions could and should serve as a clearinghouse for reliable information of this type. In some cases, interconnection customers have sought out this information from the specific transmission providers but have found that the quality of information provided is dependent on the assigned project manager in each Region, even if the interconnection customer is able to hold a pre-queue scoping meeting.

Typically, the Regions provide access to a list of valid generator interconnection applications, and some provide the process time for system integration and feasibility studies.[69] CAISO summarizes results from its interconnection studies to help identify portions of its system and points of interconnection with available headroom. The Cluster 13 report shows that there is 43 GW of energy-only headroom (33 GW of which are firmly deliverable) on its system, including projects that can either be interconnected with no network upgrades (5.4 GW), proceed with RAS (21.0 GW), or proceed with under development transmission (16.3 GW).[70]

In other Regions, access to system-wide pre-screening tools varies, but generally appears to be low quality. For example, MISO recommends that customers review its generator interconnection queue map and the contour map. However, the contour map currently available on MISO’s website is five years old, as shown in Figure 10. One viewer commented that the resolution of this map makes it not very useful. MISO also offers a Point of Interconnection Tool to assist with pre-screening, but there is no detailed information available to the public.[71]

69 FERC Open Access Transmission Tariffs (OATTs) for CAISO (Appendix Y, September 1, 2022), p. 14; ISO-NE (Schedule 22, June 5, 2023), pp. 38-42; MISO (Attachment X, January 22, 2024), pp. 48-56; NYISO (Attachment P, April 11, 2021), p. 14; SPP (Attachment V, December 1, 2020), pp. 31-32.

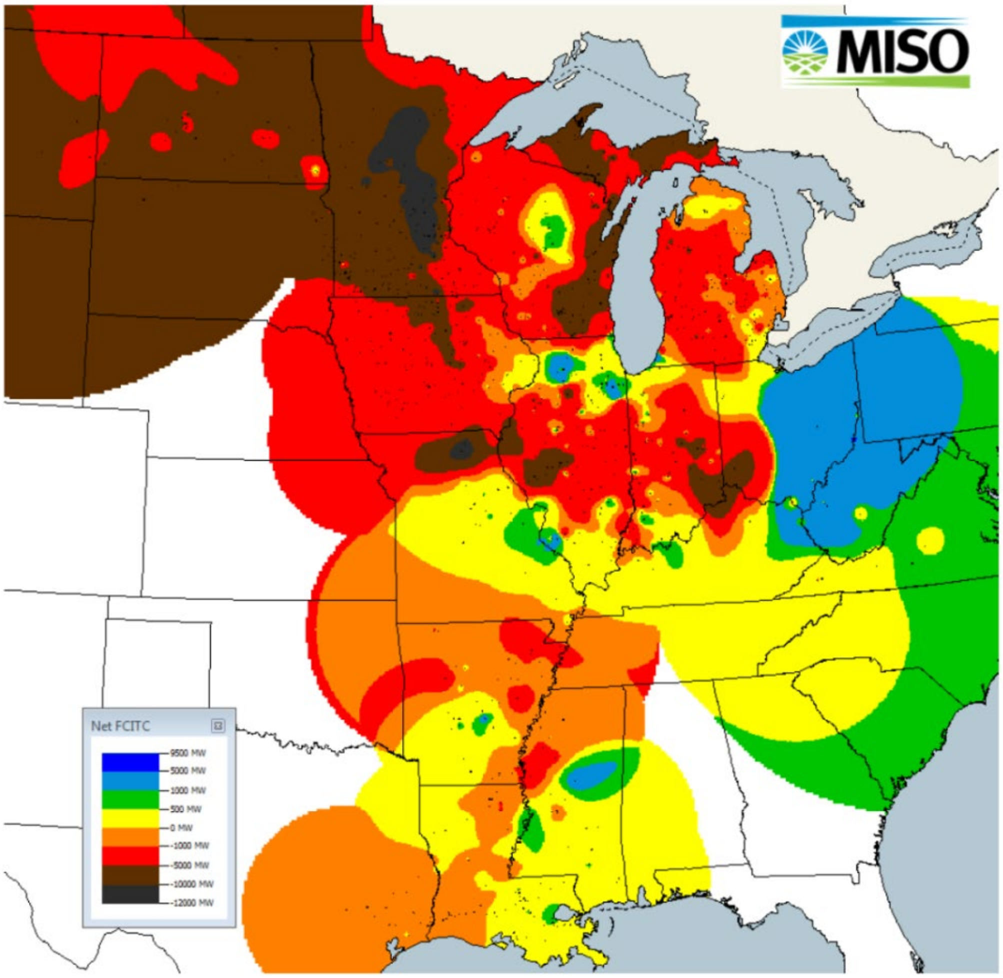
70 CAISO, *Briefing on Resources Available for Near Term Interconnection (December 5, 2023).*

71 MISO, *Queue Process Workshop: Generator Interconnection Queue (August 11, 2022), pp. 8-9.*

FIGURE 10 | MISO Contour Map[72]

Created using August 2017 Definitive Planning Phase Model for Central, MI, ATC, and South regions. August 2016 model for West region.

7/11/2018



72 MISO, *GI-Contour_Map (September 15, 2023)*.

5.3. Interconnection Study Process

In most Regions, the interconnection study processes are complex processes that have not yet adequately adapted to the significant increase in requests for interconnection over the past several years. The one Region where the large volume of requests has not greatly limited the interconnection process is ERCOT.

TABLE 8 | Interconnection Study Process Grades

	Interconnection Study Process Design
CAISO	B
ERCOT	A-
ISO-NE	C-
MISO	D+
NYISO	B-
PJM	F
SPP	D

Interconnection customers provided widespread feedback on the challenges that they face with the current processes that are caused by the volume of requests in the queue and materialize in many different ways. With such a large number of projects to study and significant interdependencies amongst the projects, poor design or execution in one particular component can be closely tied to choices made in other components, making it unclear in many cases what exactly is the root cause of the issue. Interconnection customers identified particular practices or combinations of project standards in each Region that result in unnecessary delays or unhelpful incentives to interconnection customers to remain in or exit the queue. These practices and standards evolved during a period in which the Regions' queues were smaller, and they have fared poorly as the queues expanded.

In recent policy discussions related to the interconnection study process, such as FERC Order 2023, substantial attention has been given to three areas: setting appropriate barriers to entry (e.g., site control), financial commitments (e.g., withdrawal penalties), and material modifications (e.g., small adjustments to size, technology, or point of interconnection as the project gains information through the study process). Overall, interconnection customers believe that in those three areas, the Regions have already or will soon move toward more reasonable policies and practices. This finding should not imply that the Regions have adopted workable interconnection study process designs as implementation of the reforms will be crucial to their success.

Interconnection customers also noted that several aspects of the interconnection process require balancing tradeoffs between competing objectives. For example, setting higher readiness requirements or financial commitments can limit the amount of entry but, if set

Interconnection Study Process Metrics

8. Interconnection process structure
- Entry and readiness requirements
- Withdrawal, refund, and penalty policies
- Deficiency process
- Flexibility for project modifications
- Opportunity for "fast-track" or obtain provisional service based on level of readiness
- Coordination with deliverability requirements

9. Interconnection process transparency
- Clarity of application requirements
- Availability of staff to answer questions
- Sufficiency of technical information in study reporting
- Region provides detailed queue status updates and reasons for study delays

10. Interconnection staffing and modeling resources
- Sufficiency and quality of staffing
- Quality and effectiveness of software

11. Construction of network system upgrades
- Timeliness of system upgrade completion
- Management of external factors affecting construction milestones (e.g., supply chain)

too high, those requirements could limit access to a wide range of interconnection customers and impinge upon "open access" principles. Similarly, setting more flexible rules for material modifications could be beneficial to lowering the number of initial queue requests submitted by interconnection customers (because lack of flexibility causes some customers to submit multiple requests for a single intended project), but have the unintended consequence of shifting results between system impact study phases.

Many interconnection customers noted that the existing interconnection study processes have been designed to accommodate first, gas generation and second, wind and solar generation, but are not as well suited to evaluate battery storage projects.[73]

5.3.1. Staff resources are inadequate in every respect[74]

Interconnection customers expressed widespread concern with the inadequacy of resources applied to the interconnection processes, particularly insufficient staffing levels, lack of training, poor senior talent retention, and leadership turnover affecting most or all Regions. The issue extends beyond the Regions to transmission providers, where resource challenges affect not only engineering staff, but also legal, real estate, and other offices that are critical to the transmission providers' responsibilities in completing the interconnection process.

Interconnection customers acknowledge that they have contributed to the staff retention issue as they frequently hire staff from the Regions to support the development of their project pipeline due to their particular knowledge of the markets and the often-unwritten methodology employed by each Region for completing interconnection studies. Region staff are extremely valuable to the interconnection customers in large part due to the lack of transparency in the processes and the need to understand the exact assumptions, criteria, and methodologies implemented by the Regions but not memorialized in tariffs or manuals.

To support the surge in requests, almost all Regions use consultants to deal with staffing shortages, with some trending towards more use of consultants for deliverability studies.

73 Interviews zc, zd, zg, zj, zk, zm, zn.
74 Interviews zb, zc, zd, zf, zh, zj, zn, zm, zp, zr. Contribution of project team.

Interconnection customers note that reliance on consultants does in fact increase the amount of studies completed, but also creates more challenges for the Region to coordinate across several consultants and check their work, which can reduce the quality and consistency of the results.

Some Regions, notably PJM and SPP, have made progress applying automation as a means of addressing staff limitations. However, it has not been sufficient to correct problems in general.

Individual interconnection customers also complained about specific Regions' data quality, or noted that data is out of date. For example, replication of modeling by CAISO and ISO-NE is considered difficult or impossible, especially with respect to deliverability. Interconnection customers also noted that results from SPP studies require significant review due to a lower quality of results from its process.

5.3.2. *Transparency depends on individual staffers*[75]

One key problem is that during the study process, transparency and coordination with the Regions depends very much on the individual staff member (e.g., project manager) assigned by the Region to the project. While there is some variation in transparency policies and practices, the key factor determining an interconnection customer's experience with a particular project is the project manager. The customer service at SPP and MISO was mentioned as being particularly poor.

When it comes to non-RTO/ISO transmission providers, interconnection customers find non-RTO transmission provider processes to be particularly opaque, including the providers' lack of transparency in its methods, assumptions, selection of required upgrades, or alternatives to upgrades. Interconnection customers lack the information to replicate studies and thus determine project modifications or alternative upgrades that might reduce interconnection costs.

5.3.3. *Supply chain and other construction bottlenecks*[76]

In any Region where numerous network upgrades are required, construction delays are a problem—meaning that even once projects have made it through a years-long interconnection process, they often face additional delays beyond the project developer's control before being able to come online. Supply chain constraints have recently been widespread, especially with respect to circuit breakers and transformers. These constraints result in delays for network upgrades required to bring projects into commercial operation and those delays are frequently reported to the interconnection customer once deadlines are approaching or already passed.

Some interconnection customers report that supply chain constraints are particularly acute for high voltage upgrades, with projects on facilities carrying over 345 kV taking three to four years (lower rated facilities are taking at least two and a half years). These supply chain constraints have coincided with the large increase in project development that has hampered the interconnection study process and created an additional barrier to completing the construction portion of the interconnection process.

75 Interviews zd, zm, zn, zp.

76 Interviews zb, zc, zd, zj, zm, zp.

These supply chain issues are exacerbated by both the staffing constraints mentioned above and inadequate transmission planning practices. Interconnection customers suggested that, with better planning, transmission providers could procure equipment in advance, given the volume of interconnection upgrades that are readily foreseeable. However, transmission providers may be constrained by regulatory cost recovery requirements.

A survey of interconnection customers with interconnection agreements but delays to commercial operation found that in addition to supply chain issues, obtaining all necessary regulatory approvals played a significant role in delays.[77] Delay and timeline uncertainty in the interconnection process exacerbate the challenges of achieving regulatory approvals on a timeframe that matches a project's path to commercial operation.

5.3.4. Regional assessments of interconnection study process

ERCOT: Simple can be fast[78]

Interconnection customers find ERCOT's serial process straightforward and fast. Unlike all other Regions, ERCOT is able to maintain an effective, high volume serial process because there are relatively few upgrade costs shared among multiple projects in the queue and limited need for re-study that can slow the process. Interconnection customers also find ERCOT to be transparent, with reliable data.

The ERCOT process is notable because the studies are completed by the transmission providers instead of ERCOT itself and the study criteria are focused on local upgrades required for interconnection and not deliverability to load, limiting the number of deep network upgrades required by each project. These differences have allowed ERCOT to continue to process a higher volume of requests, with some impacts on timing in recent years, although much smaller than other Regions.

Another benefit of the ERCOT interconnection process is its flexibility to accommodate modifications of the interconnection requests, such as changing the point of interconnection (POI), without requiring the interconnection customer to re-submit a new request. Even though modifications can result in some study delay, development of the interconnection agreement can continue in parallel.

One reason ERCOT's process moves forward expeditiously is that interconnection customers select and hire approved consultants to conduct system impacts studies for their projects. While interconnection customers have different opinions on the specific characteristics of ERCOT's staffing resources, they express less concern about this aspect of ERCOT's process than they do about other Regions. Similarly, interconnection customers report experiencing on-schedule construction (subject to supply chain constraints), especially with AEP and Oncor.

However, the simplicity and limited scope of ERCOT's interconnection process creates systemic risks for interconnection customers. They are exposed to high uncertainty regarding the risk

77 Andy Witmeier, *Generator Interconnection Queue Improvements (September 18, 2023), MISO Planning Advisory Committee (PAC) Special Meeting, p. 28.*
78 Interviews zb, zd, zf, zg, zh, zm, zp. Contribution of project team.

of curtailment to energy output and high basis risk to pricing hubs. One specific issue is that ERCOT does not do restudies when projects that have obtained interconnection agreements are not constructed. This results in interconnection customers receiving inaccurate information about curtailment risk. When a project gets an interconnection agreement, it is included in the base cases and thus visible to other interconnection customers. For these reasons, the biggest development risk driving withdrawal in ERCOT is anticipated congestion, and not the system upgrade costs resulting from the interconnection studies. As we note later, ERCOT's recent lack of proactive transmission planning limits its ability to identify cost effective upgrades that would reduce congestion, increase utilization of low variable cost resources already on the system, and create headroom for additional resources to be added to the system with limited curtailment risk.

One interconnection customer criticized ERCOT's overly stringent implementation of confidentiality practices (e.g., CEII), which is problematic for project screening and advancement.

CAISO: Has most of the elements, but needs some improvement[79]

CAISO's interconnection process gets highly variable reviews. Most of the problems can be traced to its insufficient staffing capacity to handle the large volume of projects in the queue, and the need for storage projects to receive actionable information on deliverability. Several interconnection customers noted the high quality of the CAISO process through Cluster 13, but increased volume in Cluster 14 and 15 have greatly slowed recent progress.

Nonetheless, aspects of the process that were viewed favorably by interconnection customers include ease of submission, site control requirements, ability to modify points of interconnection (POI), deficiency correction process, withdrawal penalties, and cost allocation rules.

CAISO also gets good reviews from interconnection customers as providing transparency around most aspects of the interconnection process. CAISO's scoping calls are very helpful and specific, with detailed meeting minutes. CASIO makes study reports, transmission plans, and market notices available. However, transmission providers in CAISO are less forthcoming with providing information related to the final stages of testing and commissioning, and completed GIAs are not accessible to interconnection customers.

Despite the difficulty of assessing whether storage projects will receive deliverability, CAISO's approach of including the cost of major network upgrades in general transmission rates gets particular appreciation, since it substantially improves cost certainty and reduces the challenge of negotiating the risk of high network upgrade costs.

Some specific complaints from interconnection customers include:

- Several interconnection customers noted the initial Phase I study in CAISO produces limited meaningful results, resulting in wasted time and effort during the early stages of the process.
- One interconnection customer views the modification process for adding storage to a solar

79 Interviews zb, zc, zh, zk zm, zn, zp.

facility as very slow, with staff appearing to ask questions of the interconnection customer just to extend the clock.

- One interconnection customer sees problems with CAISO's study of both secondary system need (SSN) and high system need (HSN), and that removing SSNs might improve the study process.

Even those aspects of CAISO's process that are viewed favorably can have downsides. When an interconnection customer locates a low-cost injection point, other interconnection customers are able to move their projects to that point without having to submit a new queue request, which CAISO allows during the customer engagement window. Interconnection customers note that this flexibility inadvertently reduces the value of good prospecting work by interconnection customers, and may exacerbate the fundamental problem of limited transmission capacity.

Similarly, the lack of site control requirements may make it easy to submit new queue requests but contributes to the excessive number of projects in the queue. With the high penalties for withdrawals, projects then remain in the queue just to defer the time when they will be assessed the penalty.

As noted above, the major problem that interconnection customers see with CAISO's process is that the deliverability allocation process is separate from the interconnection study process. Particularly for storage projects, deliverability is key to financing. Typically, deliverability is not determined until very late in the interconnection process. The likelihood of CAISO assigning transmission capacity to a project improves if it is under contract to a load serving entity (LSE), but LSEs are often reluctant to sign contracts until a project has deliverability. Because deliverability is so important, there is some disagreement among interconnection customers as to whether CAISO's process is a good or bad example of how to adapt "connect and manage" to provide the deliverability requirements of a capacity market.

Some interconnection customers explained how CAISO's readiness standards for prioritizing allocation of available (or new) transmission capacity are challenging for business practices. Storage projects' commercial viability cannot be assessed until deliverability information becomes available late in the process. This promotes late queue exit, which adversely affects other projects in the queue. Another interconnection customer views CAISO as having too low of a barrier to entry, inviting the submission of less ready-to-develop projects.

Once a project proceeds to construction of interconnection and network upgrade facilities, performance in CAISO lags that in other Regions. For example, shared facility agreements in CAISO are not as effective as in other Regions. The major problem is that projects can be delayed by as much as five years by transmission providers, who have no framework or CAISO directives to follow in the construction process. Southern California Edison gets particular criticism from some interconnection customers for their delays in constructing interconnection-related system upgrades.

NYISO: Quirks undermine a sound process design[80]

NYISO also received relatively positive reviews from interconnection customers on their process, and was frequently mentioned along with CAISO as having a relatively strong approach for its interconnection process while ensuring deliverability for capacity purposes. Interconnection customers also noted that NYISO's material modification process is reasonable, and interconnection customers particularly appreciate having access to records of NYISO's prior decisions, allowing them to rely upon a record of what NYISO considers to be a problematic modification to avoid submitting requests that will surely be rejected.

However, interconnection customers also noted several complaints about NYISO's study process that relate to specific quirks and execution. For example, under the current Phase I serial process, the barrier to projects entering the queue was too low, but the new Phase II cluster ("class year") process has higher maturity requirements. While interconnection customers generally view the maturity requirements as reasonable and effective at excluding unready projects from the queue, one interconnection customer noted that the requirements related to project permitting may be too high for that phase of the study process. If project permitting requirements are unreasonable, it could result in projects being put on hold in the middle of the interconnection study, requiring the interconnection customer to invest significantly in project permitting without having information about potential interconnection costs.[81]

At least one interconnection customer reported difficulty in interpreting NYISO's submission requirements. As a result, that interconnection customer experienced more deficiency notifications than it receives in other Regions.

In terms of timing, NYISO consistently misses its schedule estimates, does not reliably provide schedule updates, and overall makes it difficult for interconnection customers to get information.

ISO-NE: Burdensome and vague study process[82]

Interconnection customers have less familiarity with the ISO-NE process, perhaps due to lower development of generators compared to other Regions. Those interconnection customers who know the process well note that ISO-NE's burdensome process creates a barrier to entry. One challenge noted by interconnection customers is that ISO-NE's study process includes study requirements that are not imposed by other Regions. For example, applications must include a PSCAD model of their project for stability studies, which are a large part of the study process. Developing these benchmarking models is a high cost, time consuming requirement (which causes version control issues), and an expense that other Regions do not require during the application phase (but may require later as needed). The burden of these requirements is especially severe for projects in Maine where the system is constrained and requires additional studies to identify the necessary upgrades.

80 Interviews zd, zh, zk.

81 On the other hand, it is appreciated that projects do not need to be fully permitted to obtain a GIA.

82 Interviews zd, zk, zr.

On the other hand, one interconnection customer notes that even though the process has historically been "clunky," with delays in Maine and southeast Massachusetts near offshore wind points of interconnection, the forthcoming transition to a cluster system might make things worse based on initial experiences in Maine. As a "sensitive system," the interconnection customer feels that ISO-NE's relatively high barriers to queue entry are reasonable.

Another problem is driven by ISO-NE failing to provide a lot of details or standards prior to submission of interconnection applications so that the interconnection customer can ensure that the submission is sufficient. ISO-NE does have a portal process that gives interconnection customers access to transmission adequacy and reliability assessment modeling modules. One interconnection customer notes that in considering necessary changes for Order 2023 compliance, it appears that many existing study assumptions and criteria are not documented in the planning procedures and business manuals, especially as compared to other Regions like MISO and SPP.

Possibly as a result of the problematic interconnection study assumptions, interconnection customers tend to receive deficiency notices late in the process, introducing potentially years of unnecessary delay while the models are reworked for resubmission. While the requirement is not fundamentally objectionable, the extra burden and poor implementation make this a big negative. Interconnection customers also complain about the lack of transparency on unit costs for upgrades and schedule updates, citing a need for overall improvement in transparency. ISO-NE does have a portal process that gives interconnection customers access to transmission adequacy and reliability assessment modeling modules.

MISO: Inconsistent application undermines a good process[83]

Interconnection customers generally appreciate the structure of the MISO interconnection process because it moves progressively towards increased certainty, with reasonable early project milestones and readiness requirements. MISO is relatively transparent and provides clear responses to interconnection customer questions that refer back to the tariff and business practice manuals, giving interconnection customers confidence in the responses. MISO also makes it relatively easy to submit modifications, subject to material modification review.

But, some interconnection customers believe that MISO's interconnection study process is undermined by inconsistent application of penalties for withdrawals. Other interconnection customers express concerns about specific sub-regions, one most concerned about MISO-North, another about MISO-South.

Interconnection customers also comment that another counter-effective aspect of MISO's process is that MISO study results tend to have a large number of contingent upgrades; with a low penalty withdrawal policy, interconnection customers getting study results with excessive costs may decide to remain in the queue, just in case the costs improve. MISO's current "definition of harm" results in 40% of projects that reached the latter stages of MISO's queue being eligible for penalty-free withdrawal.[84] This defers project exit from the queue, which

83 Interviews zb, zf, zh, zj, zm, zn, zp, zr.

84 Charles River Associates, *MISO Interconnection Queue: M2, M3 and M4 Security Deposits and Return Procedures (August 26, 2023), presentation to MISO, pp. 12, 14.*

results in what is likely to become inaccurate cost information for more viable projects. Recent reforms related to withdrawal penalties and milestone payments may address these concerns.

Construction management varies across MISO, with MISO itself taking a hands-off approach. Mid-American, ITC Midwest, and Duke are all cited as managing construction effectively (subject to supply chain constraints), while transmission providers in MISO-South come in for particular criticism. Looking forward, some interconnection customers are concerned that the buildout of projects in the long-range transmission plan may not be well coordinated with project-related network upgrades, further delaying the upgrades.

SPP: Inconsistent application undermines a good process[85]

Similar to MISO, interconnection customers think the process is well-designed in phases, which should give interconnection customers an opportunity to assess risks as the project progresses through the studies. However, several interconnection customers noted that aspects of SPP's implementation of its process undermines its effectiveness. SPP inconsistently applies aspects of its interconnection tariff, specifically SPP's penalties for withdrawals – interconnection customers actually think that SPP is insufficiently punitive.

SPP also provides procedures for transparency, including monthly updates and a tracking system for questions submitted by interconnection customers. Initial reactions to SPP's automation pilots for data entry and data validation were positive.[86] According to SPP, it processed 78 generator interconnection agreements in the latter half of 2023, which is more than four times SPP's annual agreement execution rate for the prior four years – one company attributes this improvement to automation.[87]

However, interconnection customers complained about inconsistency and poor quality in several areas. Customer service is poor; responses to questions are unreliable and are not routinely referenced to the tariff or business practice manuals. And, as discussed in Section 5.1.3, several interconnection customers noted that they have received study results with significant errors, and that SPP provides slow responses to inquiries about those errors.

On the other hand, interconnection customers did not identify any particular problems with construction of upgrades in SPP. One interconnection customer noted that multi-party facility construction agreements are reasonably effective in SPP.

PJM: Poor queue management, quality control, and unreasonable policies[88]

Interconnection customers are very critical of PJM's interconnection study process. In the now-replaced serial process, their largest complaint was that there was little financial commitment until PJM was ready to offer an interconnection agreement to a project. As a result, projects would drop out too late in the process, causing a high number of restudies (5-6), which is

---

85 Interviews zb, zf, zh.

86 SPP, *2023 ITP Needs Assessment, p. 1; William Driscoll, "Artificial Intelligence Could Speed Interconnection, Says Amazon Executive," PV Magazine USA (October 17, 2022).*

87 Pearl Street Technologies post to LinkedIn (January 2024), available at: https://www.linkedin.com/posts/pearlstreettechnologies_exciting-milestone-spp-successfully-processed-activity-7148712245621952512-iwWy/

88 Interviews zb, zf, zh, zj, zn.

inefficient and delays the process for most projects.[89] PJM does not provide reliable schedule updates either.

While interconnection customers are able to replicate PJM's results due to model availability, this advantage is undercut by PJM's routine failure to proactively communicate identified errors in the model and issue corrections for those models. Furthermore, multiple interviewees stated that PJM staff give unreliable responses to questions, and PJM's business practice manuals are less detailed than other Regions.

PJM is often too "wedded" to its standards, which don't always make sense and can lead to unreasonable outcomes. For example, it is relatively easy to submit modifications, but some interconnection customers observe that PJM considers *any* change in electrical configuration to be a material modification that requires time-intensive restudy analysis by PJM staff, freezing the clock on PJM's study schedule. Furthermore, PJM's modification policies are very restrictive in terms of fuel/technology type.

In theory, interconnection customers like PJM's recently adopted phased approach, approved by FERC in 2022, that addresses both of the concerns noted above concerning financial commitment and model updates. When implemented, it should give them the opportunity to assess risks as the project progresses. As a part of the transition to its new process, PJM has halted new applications until 2025 and has estimated that new requests will receive interconnection agreements in the later years of the decade. This delay is a concern for interconnection customers looking to develop projects in PJM.

Another area where interconnection customers see unnecessary restrictions in PJM is in construction. Even though PJM is more involved in tracking construction than some other Regions, its poor project management means that logistics and issue resolution are challenged. While Dominion and Eastern Kentucky Power Cooperative projects move forward relatively well, ComEd and AEP do not move projects forward on a reasonable schedule.

89 Some interconnection customers comment that PJM's new process is much improved, with clear withdrawal penalties.

5.4. Interconnection Study Assumptions, Criteria, & Replicability

Overall, interconnection customers felt that problems with interconnection study assumptions, criteria, and replicability were systemic across most Regions. In particular, projects can be exposed to unreasonable risk from affected system studies and from discrepancies between interconnection and resource adequacy studies. When projects are affected by these problems, it can leave cost uncertainty unresolved until the very end of the process, which inhibits uneconomic projects from leaving the queue earlier in the process.

TABLE 9 | Interconnection Study Assumptions & Replicability Grades

	Interconnection Study Assumptions & Replicability
CAISO	A
ERCOT	A+
ISO-NE	C+
MISO	D
NYISO	C+
PJM	F
SPP	C

In theory, the progression of studies in the interconnection process is intended to give interconnection customers early signals to exit the process if their project is likely to trigger high interconnection costs. However, in reality, much of that cost uncertainty is entirely deferred to the very end of the process, when an interconnection customer is presented with a generator interconnection agreement, or even up to the point of commencing commercial operation.

The biggest risk for many projects is the uncertainty of whether — and when — a potentially affected system will inform the interconnection customer of large upgrade costs on a system that is neither the host nor the customer of the project. (ERCOT is an exception because such studies are rarely a factor due to the limited scope of interconnection studies in general.)

Another late-stage cost uncertainty results from discrepancies between the assumptions used in interconnection studies and those used in resource adequacy studies.[90] For example, to qualify new generators to supply network transmission service to load customers, SPP utilizes a separate post-interconnection agreement study to examine aggregate delivery. This study utilizes different methods and assumptions than the interconnection studies—even for projects which have achieved NRIS status. This additional study can identify further upgrades, increasing project costs to meet aggregate delivery. In CAISO, studies to evaluate the allocation of Transmission Planning Delivery (TPD) occur in tandem with the later stage queue and

90 In Regions with resource adequacy requirements, resource adequacy studies evaluate the contribution of generation units to meeting resource requirements under a wide range of circumstances. Generally, this results in valuing the capacity of renewable energy and energy storage projects at less than nameplate capacity. But interconnection studies, those resources are usually evaluated at nameplate capacity output.

employ different assumptions and methodologies for resource adequacy. This study is pivotal since the allocation of TPD is a requirement for procurements issued by utilities, community aggregators, and other load serving entities in satisfying their resource adequacy obligations.[91]

Even though these problems can (and do) affect projects across most Regions, grades for this Scorecard category vary widely. Region-specific circumstances or study practices mitigate the impact of these problems in some Regions, but the problems are experienced more severely and by more projects in other Regions.

Interconnection Study Assumptions, Criteria, & Replicability Metrics

12. **Transparency of study criteria and assumptions**
13. **Reasonableness of modeling criteria and assumptions**
14. **Consistency of generator facility modeling characterization throughout all studies**
15. **Consideration of Grid Enhancing Technologies (GETs) when evaluating network upgrades mitigation**
16. **Alignment of process with distribution interconnection studies**
17. **Interconnection study coordination with neighboring systems**
18. **Transmission provider studies are accurate and well-coordinated with Region**

5.4.1. Affected system studies

Affected system studies were among the most forcefully criticized topics in our interview process, as previously discussed in Section 5.1.1. While interconnection customers acknowledge that FERC Order 2023 is attempting to improve affected system studies, the lack of standard approaches to affected system studies, inconsistent modeling assumptions between Regions, and the time required to complete the studies has created significant uncertainty for interconnection customers about the affected system study schedule and interconnection costs.

In terms of modeling criteria for affected system studies, interconnection customers felt that the host system's modeling criteria should govern analysis in neighboring systems. It is their view that it is unreasonable to apply stricter contingency concerns for power that is not being delivered to a system. In general, modeling criteria should be standardized in some fashion across the country. While generic assumptions about generator performance (export and charging cycle schedules and rates, in particular) could be made, they need to be handled in a consistent manner across the Regions so as to avoid contradictions between how one transmission provider and another evaluate a project's performance.

Among the Regions, interconnection customers cited the SPP-MISO and MISO-PJM seams as most problematic. However, one interconnection customer mentioned that a coordination agreement between PJM and MISO helped with the extensive border between those Regions.

91 In Regions with resource adequacy requirements, resource adequacy studies evaluate the contribution of generation units to meeting resource requirements under a wide range of circumstances. Generally, this results in valuing the capacity of renewable energy and energy storage projects at less than nameplate capacity. But interconnection studies, those resources are usually evaluated at nameplate capacity output.

Seams between the Regions and other transmission systems were also referenced as typically problematic.

5.4.2. Modeling criteria and assumptions

Interconnection customers generally felt that there are systemic problems with modeling criteria and assumptions. Although in the past, these problems were not particularly impactful, the growth of queue size has caused the model results to diverge from reality, triggering potentially unnecessary deep network upgrades. Where unreasonable study assumptions are an issue, the consequences ripple into every aspect of the interconnection process and drive unnecessary costs that are ultimately borne by the ratepayer and increase the time required for the interconnection process due to the need to re-study system impacts as projects withdraw.

Interconnection customers did acknowledge that with respect to the models of each projects' generator, the Regions and transmission providers all accept the model provided by the interconnection customers. Furthermore, interconnection customers agree that the Regions apply their business practice manuals consistently in interpreting those models.

For Regions with capacity markets, interconnection customers pointed to the discrepancies between the assumptions in interconnection studies and those used in resource adequacy (capacity accreditation, or ELCC) studies.

5.4.3. Evaluation of options to accelerate upgrades

Another across-the-board criticism was the failure of the Regions or transmission providers to respond reasonably to suggestions to consider grid-enhancing technologies (GETs). (FERC Order 2023 now requires such consideration, but leaves much up to the discretion of the transmission provider.) Use of GETs can expedite commercial operation of new generation at relatively low cost, as well as providing the Regions with an opportunity to optimize permanent network upgrades through the transmission planning process.

5.4.4. Regional assessments of interconnection study assumptions, criteria and replicability

ERCOT: Simple requirements, reasonably executed[92]

As noted above, ERCOT interconnection studies are limited to the impacts on the local system on an energy-only basis, resulting in limited needs for extensive upgrades and providing the interconnection customer with information for assessing its curtailment risks once operation. Specifically, ERCOT applies a higher transfer distribution factor (DFAX) for determining responsibility for network upgrades and economically re-dispatches the system in response to the additional injections of the studied resource. For these reasons, ERCOT's modeling assumptions and criteria are generally not a concern, and were characterized as "very up-to-date."

92 Interviews zf, zg, zm.

CAISO: Accessible and reasonable[93]

CAISO makes models accessible and uses reasonable modeling assumptions. Furthermore, transmission providers in CAISO have improved their worst-case study assumptions and, to the extent that costly upgrades are required, the RAS can make the outcome more reasonable. While affected system study issues are rarer than some other Regions, problems can occur near municipal transmission systems.

ISO-NE: Complex, but not unreasonable[94]

Interconnection customers expressed mixed opinions on the reasonableness of modeling criteria and assumptions. One interconnection customer identified challenges driven by New England Power Pool[95] policies that affect system integration study assumptions.

Another interconnection customer discussed the evaluation of projects connected at the distribution level. Because these projects are not subject to direct study review by the Regions, the initial studies are conducted by the local distribution system provider. Studies for smaller projects connected at the distribution level can be even more complex than for projects connected at the transmission level, resulting in the smaller project absorbing proportionately larger costs. The aggregated effect of these distribution-level projects can have a significant and complex impact on the costs and timelines of transmission system studies.

On the other hand, affected system studies are not a big problem in ISO-NE. Because projects along the NYISO border can trigger affected system studies, interconnection customers tend to avoid this portion of the system.

NYISO: Inconsistent model assumptions, difficult to access[96]

Interconnection customers cited challenges with model assumptions. One interconnection customer states that NYISO assigns sub-zones “on the fly” and so working in areas like Long Island entails study results that very hard to predict or replicate. Another interconnection customer cites unspecified issues with assumptions and reasonability. In addition, the process to access the base case models can take many months and require several attempts at following up with NYISO.

NYISO provides a good example of the complexity of evaluating new generation being studied for connection at the distribution level. When NYISO identifies transmission upgrades to unlock capacity for projects connected at the transmission level, that new headroom can easily be used by distributed generation projects that NYISO’s study process did not consider.

Furthermore, NYISO’s study results are difficult or impossible to replicate. The study data provided by NYISO are insufficient to enable interconnection customers to understand how the results were obtained. In particular, the information provided from the class year cluster study is

---

93 Interviews zc, zh, zk, zm, zr.

94 Interviews zd, zk, zr.

95 New England Power Pool (NEPOOL) is the independent, FERC-approved stakeholder advisory group for wholesale market and transmission tariff design.

96 Interviews zd, zh, zk.

insufficient for interconnection customers to make an informed decision on whether to remain in the queue.

***SPP: Good reporting, but systemic problems with quality and changing standards*[97]**

SPP's studies are reported in a detailed workbook that enables analysis and cost attribution, particularly where network upgrade costs are shared among projects. However, SPP is reported to have issues with consistency, ascribed to both poor quality control and changing rules/standards as the process moves forward. One case study points out that low transfer distribution factor (TDF) thresholds create excessive interdependency between projects that have minimal impact on even very distant facilities where upgrades are required.[98] Furthermore, legal reviews to get access to base case models from SPP are taking many months, requiring lots of follow-up.

***MISO: Overly conservative, with poor quality, but accessible to interconnection customers*[99]**

Interconnection customers heavily criticized the use of a low DFAX threshold in MISO, particularly as used by transmission providers. As noted above, the DFAX threshold has a significant impact on the location and scale of network upgrades identified in the interconnection studies, with lower thresholds resulting in the need for deep network upgrades further from the point of interconnection.

After MISO recently decreased its DFAX threshold, interconnection customers are seeing additional and often distant network upgrade requirements for both ERIS and NRIS interconnection requests. Examples of specific transmission providers using even lower (more restrictive) DFAX thresholds were suggested by interconnection customers, who expressed concern that they are triggering additional system upgrades beyond those identified in MISO's system impact studies.

Another example is the use of more stringent local planning criteria by Great River Energy (GRE). The stricter "n-1-1" criteria causes its planning cases to include additional gas peaker dispatch beyond those in MISO's planning cases, resulting in excessive network upgrade costs. These higher costs trigger withdrawals of projects from the queue.

One interconnection customer ascribes excessive upgrades in MISO to the queue size, compounded by modeling errors of facility ratings, which together create phantom issues and results that are not replicable. MISO's poor quality control is often not evident until relatively late in the process.

MISO does provide access to full model results and its business practice manuals. However, similar to NYISO, the approval process for gaining access to base case models from MISO is taking many months and requiring lots of follow-up.

---

97 Interviews zb, zh, zm, zr; project team contribution.

98 Aaron Vander Vorst and Adam Stern, *Plugging In: A Roadmap for Modernizing & Integrating Interconnection and Transmission Planning (October 2021), Enel Green Power Working Paper, pp. 18-20.*

99 Interviews zb, zf, zg, zh, zm, zr; project team contribution.

PJM: Non-transparent and arbitrary study practices[100]

While PJM's policy is to make its models accessible, the posting of study models used in the 2022 reformed queue process has been delayed. In the past, PJM's models were difficult to use. Prior to its 2022 reforms, PJM's models and study results were in individual files, which challenged analysis, particularly around project interdependencies.

Even today, PJM's study predictability/replicability is poor, both because models for the 2022 reformed queue process are not yet available and, in clusters with multiple projects, PJM does not disclose the modeling assumptions for other projects. Another specific concern is that PJM's criteria for voltage recovery has caused a lot of issues for interconnection customers. Without the capability to do independent analysis, interconnection customers cannot obtain shadow study results to understand upgrade exposures and cost risk. One interconnection customer characterizes PJM's power flow analysis as an effort to find problems that do not necessarily exist.

Concerns related to deep network upgrades are also common in PJM. Interconnection customers noted that PJM study assumptions result in projects needing to complete a significant number of re-studies as earlier projects in the queue dropped out.

Non-RTO/ISO transmission providers[101]

Interconnection customers criticize non-RTO/ISO transmission providers as neither transparent nor willing to provide standardized study results, and would rank many of those providers at the bottom of the list.

5.5 Availability of Attractive Interconnection Alternatives

TABLE 10 | Interconnection Study Assumptions & Replicability Grades

Availability of Attractive Interconnection Alternatives	
CAISO	B+
ERCOT	B
ISO-NE	D
MISO	B-
NYISO	D
PJM	D
SPP	B

100 Interviews zb, zd, zh, zj; project team contribution.
101 Interviews zm.

Overall, interconnection customers did not identify large differences between the Regions making attractive interconnection alternatives available, with the exception of CAISO and MISO, which stood out as providing reasonable alternatives, and ERCOT, whose default process would be an "alternative" in any other Region. For the other four Regions, interconnection customers felt that generally speaking, alternatives were not widely available.

Availability of Attractive Interconnection Alternatives Metrics

19. Attractiveness of ERIS
- Frequency of ERIS use
- Cost of ERIS compared to NRIS
- Speed of ERIS study

20. Alternative mitigation: Opportunity to use remedial action schemes (RAS) to resolve network upgrade requirements

21. Ease of sharing and transferring existing points of interconnection

5.5.1. ERIS vs NRIS: ERIS is little used, and impacts incumbent generators

Possibly the largest area of divergence among interconnection customers interviewed for this report regarded the role of ERIS or other limited operation operating approvals. (See explanation of ERIS and NRIS in Section 2.) ERIS interconnection requests do not require firm transmission service (i.e., deliverability) and should cost less and require less time to interconnect than an NRIS project that requires firm point-to-point deliverability. Deliverability often triggers deep network upgrades to the transmission system far from the point to which they are attempting to deliver power. Some Regions and utilities require all renewable generators to be studied as NRIS projects, by choice or state policy.[102] Most interconnection customers generally appreciated the opportunity to interconnect on a limited or restricted basis, and then obtain firm "deliverability" interconnection rights at a point in the future.

However, one interconnection customer felt strongly that high use of ERIS interconnection service was problematic, particularly as new ERIS projects can come online near an operating NRIS project. Unless there is a method to prioritize existing generation in operation (and generally there is not), then in its view ERIS is not a good solution because it imposes curtailment, congestion, and a loss of value for existing incumbent projects, including NRIS projects that have paid for network upgrades and received firm delivery rights.

The inherent tension between incumbent generators and new facilities created by meaningful ERIS interconnections means that scoring the Regions on the availability of attractive interconnection alternatives is not straightforward. Since ERIS interconnections are a small percentage of projects, this tension did not affect this category's grades very much. Because so few of the Regions are making any meaningful use of these approaches, most Regions earned poor marks in this category.

102 Tyler H. Norris, *Beyond FERC Order 2023: Considerations on Deep Interconnection Reform* (August 2023), Nicholas Institute for Energy, Environment & Sustainability, p. 6.

Interconnection customers' impression that most Regions do not provide a meaningful ERIS pathway is corroborated by data from LBNL's *Queued Up report*, as shown in Table 11.[103] Table 11 includes the amount of projects that are either completed or active in a queue.

ERIS is most frequently utilized by interconnection customers in SPP with 91% of projects that became operational from 2015 to 2020 selecting ERIS and 79% of projects with an executed Interconnection Agreement choosing ERIS. Most Regions are seeing a higher amount of ERIS requests for active projects relative to projects that completed the process already with 10% of queue capacity in CAISO currently seeking ERIS. ERIS has not frequently been chosen in MISO, PJM, and ISO-NE.

In PJM and SPP, ERIS projects cost significantly less than NRIS projects. Since ERIS projects do not require network service and thus are not supposed to be assessed for upgrade costs to ensure deliverability, one would expect ERIS projects to cost less than NRIS. However, Table 11 shows that in MISO ERIS projects cost 50% more than NRIS projects.

103 Data on this point vary by Region.
- CAISO – No cost data available.
- ERCOT – All projects in ERCOT are similar to ERIS projects by definition, but no cost data available.
- NYISO – Does not provide distinctions between ERIS and NRIS projects.
- ISO-NE – Identifies all recent projects as either network resources or capacity network resources – both categories are interpreted to represent NRIS projects.
- PJM – Identifies project as Energy (interpreted as ERIS) or Capacity (interpreted as NRIS).
- MISO and SPP – Identify projects as ERIS or NRIS.

TABLE 11 | ERIS vs NRIS: Cost and Participation, Projects Submitted to Queue 2015-2020[104]

	Nameplate Capacity (MW)		ERIS % of Total	Interconnection Cost ($/kW)	
	ERIS	NRIS		ERIS	NRIS
ACTIVE PROJECTS					
CAISO	17,474	159,432	10%	(no data)	
ISO-NE	2,077	38,166	5%	(no data)	208.0
MISO	6,290	112,485	5%	383.0	248.8
PJM	2,266	201,364	1%	136.2	291.1
SPP	15,802	33,917	32%	79.4	85.2
Total Active	43,910	545,365	7%	$ 135.3	$ 225.6
PROJECTS WITH EXECUTED IA					
CAISO	3,240	45,131	7%	(no data)	
ISO-NE	0	5,161	0%	n/a	128.9
MISO	2,862	55,579	5%	517.6	306.1
PJM	217	43,473	0%	82.6	33.8
SPP	10,498	2,814	79%	46.4	78.2
Total IA Executed	16,818	152,158	10%	$ 136.6	$ 193.5
OPERATIONAL PROJECTS					
CAISO	35	2,556	1%	(no data)	
ISO-NE	433	697	38%	(no data)	252.8
MISO	2,191	28,908	7%	135.8	81.0
PJM	1,159	17,657	6%	9.9	28.6
SPP	10,844	1,047	91%	38.3	31.9
Total Operational	14,661	50,865	22%	$ 51.6	$ 70.9
Total IA Executed, Operational	75,388	748,387	9%	$ 110.4	$ 196.2

Note: Some projects lack ERIS/NRIS designation and are excluded from this analysis. Projects that include both ERIS and NRIS capacity are reported as NRIS.

5.5.2. Other interconnection alternatives: Meaningful in CAISO and a few other systems

Interconnection customers also expressed frustration with limitations on other alternative interconnection practices. For example, even when a host system allows the use of a remedial action scheme (RAS), a neighboring transmission system can reject or stall approval of that solution. CAISO and transmission providers Ameren and Duke (in MISO) are among the rare

104 Analysis of LBNL, *Queued Up* dataset.

transmission providers that were credited with allowing use of an RAS or similar alternative to costly network upgrades, but they are not in a position to insist that a neighboring (affected) system also accept the use of the RAS.

Another alternative interconnection practice, surplus service, was not easy to evaluate on a Region-by-Region basis, potentially due to its relatively limited use until recently. Surplus service is the use of existing capacity for new generators that does not trigger any upgrades or adverse impacts. This capacity is made available by agreement for the original generator to be displaced by the surplus service generator. Interconnection customers generally observed that it was either too rarely an opportunity in many Regions or a burdensome process to navigate.

SPP's rules on limited operations allow for commercial operation with a temporary, lower capacity limit if transmission upgrades are scheduled to be in-service at a later date.[105]

5.5.3. Regional assessments of availability of attractive interconnection alternatives

CAISO: Most effective in using alternatives to full interconnection[106]

CAISO has both a meaningful ERIS interconnection pathway as well as widespread use of temporary remedial action schemes (RAS). For example, storage projects can often avoid upgrades related to their charging cycles by accepting a RAS to limit the schedule or rate of charging.

Unfortunately, interconnection customers report a scarcity of opportunities to request surplus service in CAISO by displacing existing generation with clean energy facilities with lower marginal costs, so this process is relatively untested.

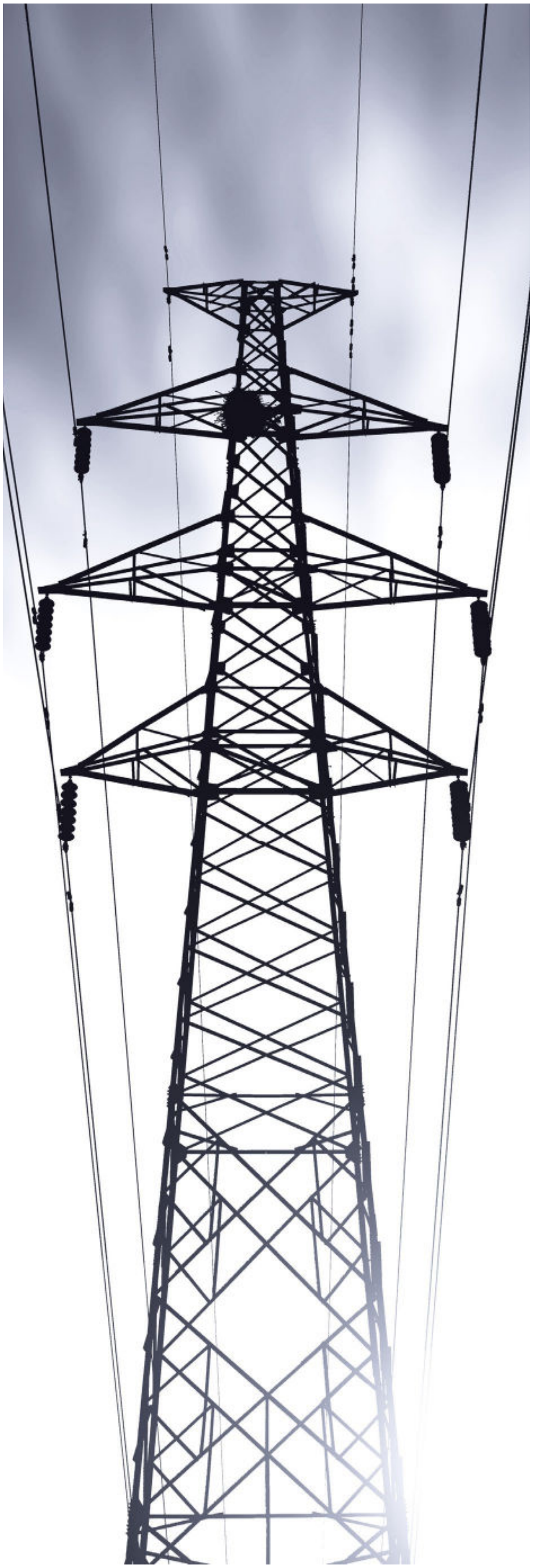
ERCOT: Virtually all interconnections essentially use "alternative" to full upgrades[107]

Because ERCOT interconnection is always at risk of curtailment due to congestion costs, ERCOT is the only Region that allows alternatives to interconnection upgrades by default. A flip side of this, discussed elsewhere in this report, is that projects in ERCOT are at high risk of substantial curtailment due to congestion, and neither ERCOT nor the transmission providers in Texas prioritize proactive transmission planning to reduce curtailment. These factors erode the delivery of power and potentially drive up energy costs even where transmission upgrades are cost effective given high congestion and curtailments.

MISO: Inconsistent availability of alternatives to standard interconnection costs[108]

Interconnection customers pointed to MISO as imposing significant, costly network upgrades on ERIS projects that are comparable to those imposed on NRIS projects. As discussed above, the data in Table 11 validate interconnection customers' impressions. The actual or forecast cost to interconnect ERIS projects is more than *double* the cost for NRIS projects. This may reflect

105 SPP Tariff, Attachment V (December 1, 2020), pp 57-58.
106 Interviews zb, zc, zg, zn.
107 Interview zg; project team contribution
108 Interviews zb, zf, zg, zj, zm, zn; Project team contribution



interconnection customers selecting ERIS status at a cost that is higher than average NRIS projects because at those particular points of interconnection, the ERIS cost represents a substantial cost savings relative to NRIS.

Interconnection customers note that in the past MISO facilitated interconnection of ERIS projects more effectively.[109] Until recently, MISO was using a DFAX threshold of 20% for ERIS projects. With this relatively higher DFAX threshold, upgrades for ERIS projects were only required on transmission facilities located electrically close to the project. However, now that MISO has lowered DFAX to 10% for ERIS projects, interconnection customers report seeing ERIS projects with higher costs, similar to NRIS projects, limiting the rationale for selecting ERIS. One important distinction on lowering the DFAX threshold is that the change was not implemented in MISO South, because that subregion of the RTO did not participate in the 2022 LRTP Tranche 1 expansion.

What alternatives are available to interconnection customers in MISO appears to depend on the transmission providers. As shown in Table 12, of the twelve MISO transmission providers with substantial ERIS project capacity, five (highlighted in grey) have ERIS costs that are higher than NRIS costs, while seven have ERIS costs that are lower than NRIS costs. Clearly certain transmission systems are less costly and easier to develop on than others.[110]

109 The LBNL *Queued U*p data do not support this perception. Even projects older than those analyzed in Table 4 have ERIS project costs that are higher than NRIS project costs.

110 The scope of this report did not allow for investigating the root cause of these differences. Challenges to cost-effective interconnection on a system may relate to real facility constraints, or may relate to policies and practices that drive up interconnection costs. An additional reason may be the use of stricter Local Planning Requirements by certain transmission owners in MISO that are incurred in higher proportion for ERIS projects than NRIS projects.

TABLE 12 | ERIS vs NRIS in MISO: Selected Transmission Providers Project Capacity and Costs; Operational, IA Executed, and Active-in-Queue Projects[111]

MISO Transmission Providers	Nameplate Capacity (MW)		Cost ($/kW)	
	ERIS	NRIS	ERIS	NRIS
Montana-Dakota Utilities	352	1,460	760.4	845.3
Cleco	642	2,700	576.3	430.8
ITC Midwest	530	7,757	564.2	257.5
Great River Energy	590	1,718	531.2	876.5
Xcel Energy	444	7,315	462.4	220.2
Otter Tail Power	1,616	3,347	337.7	638.8
Dairyland Power	174	150	331.8	255.2
MidAmerican Energy	500	7,780	305.3	234.6
Entergy	2,436	24,973	261.4	282.8
ATC	199	12,481	82.1	109.2
Duke Energy	417	1,253	41.8	94.0
Ameren Illinois	150	7,848	20.4	61.3
Total	8,102	103,664	$ 356.7	$ 225.2

Note: Total in Table 12 does not match MISO total in Table 11 because Table 12 excludes (a) 19 transmission providers that did not have significant ERIS project capacity and (b) projects that lack cost data.

Some interconnection customers see MISO's process for transferring existing interconnection rights from old generation to new generation as, at least, "functional." These interconnection customers recognized that MISO implemented surplus service and replacement processes early and has active requests for these alternatives. (SPP has a very similar process.[112]) However, other interconnection customers view surplus service and replacement processes less favorably, having experienced what they felt was an unnecessarily administrative and burdensome process. This problem seems to be centered in the transmission providers (rather than MISO itself), who have a tariff-defined role in consenting to use of shared facilities.

Another example of transmission providers' role in finding less costly paths for generator interconnection is in the use of remedial action schemes (RAS) or other alternative mitigation strategies. Interconnection customers find some consideration for these approaches in MISO, although it varies across transmission providers.

111 Analysis of LBNL, *Queued Up* dataset.

112 Ben Greene, *MISO/SPP Generator Replacement Process* (July 31, 2023), presentation to PJM Interconnection Process Subcommittee.

5.6. Regional Transmission Planning to Facilitate Generator Interconnection

Using Regional Transmission Planning Metrics

22. Regionally planned transmission supports generator interconnection

23. Regional transmission planning considers upgrades identified through interconnection studies

With the exception of CAISO and MISO, interconnection customers stated that the existing transmission planning processes are ineffective at identifying needs for and creating plans to upgrade the available headroom on the system to support the interconnection of new generation. Instead, most Regions' transmission planning activities are focused on existing reliability needs or future load requirements. In most Regions, there do not appear to be transmission planning practices to consider constraints or major network upgrades identified by interconnection studies.

Another shortcoming in most Regions is that upgrades planned by transmission providers in many Regions may not be reflected interconnection study models until construction schedules are finalized. Interconnection customers suggested that less strict schedule certainty requirements could enable generator interconnection studies to reflect the benefits of planned transmission projects at an earlier point in time.

TABLE 13 | Interconnection Study Assumptions & Replicability Grades

Using Regional Transmission Planning	
CAISO	A-
ERCOT	D
ISO-NE	D
MISO	B
NYISO	C+
PJM	D+
SPP	C+

5.6.1. *Regional assessments of regional transmission planning to facilitate generator interconnection*

CAISO: Planning focused on supporting new generation[113]

CAISO's transmission planning process gets the most appreciation from interconnection customers because it is resulting in significant upgrades that facilitate firm paths for future generation resources from the point of injection to load serving entities, a concept known as "deliverability." CAISO proactively plans transmission for the future resource mix; its annual planning process takes into account future generation needs as determined by the California Public Utilities Commission (CPUC).

113 Grid Strategies LLC, *Resolving Interconnection Queue Logjams: Lessons for CAISO from The US and Abroad* (October 2021), p. 14. Interviews zb, zh, zm, and zn.

Interconnection customers also appreciate that CAISO's planning process is designed to direct system investment by transmission providers to provide greater deliverability for projects that have received approval for limited operations (e.g., ERIS). When system upgrades are constructed, already-existing and future projects have the opportunity to obtain rights to deliver power to their customers.

CAISO's planning process accounts for future generation by forecasting additional generation, retirements, and estimates of distributed energy resources. This estimate is developed in partnership with the California Public Utilities Commission (CPUC). CAISO then classifies selected transmission projects as being driven by reliability, public policy, or economic justification.[114] Its recent transmission plans have identified several billions of dollars of upgrades specifically to support the interconnection of new generation resources to meet its policy goals.

However, CAISO's process falls short in some areas. First, some interconnection customers are unclear on what the threshold is for upgrades to be identified that would benefit one project, but would leave another project without any benefits from upgrades. Another problem is that construction of these projects is running well behind schedule.

MISO: Looking forward to improvements, anxious about the South[115]

Looking backward, most interconnection customers have not seen much benefit from MISO's transmission development process in recent years, likely due to the 10-year gap between the completion of the Multi-Value Projects (MVP) study in 2011 and the more recent Long-Range Transmission Planning (LRTP) process. The lack of large-scale regional upgrades in that timeframe increased the stress placed on the interconnection process to identify necessary upgrades and reduce the congestion on the MISO system.

However, looking forward, the results of LRTP Tranche 1 are viewed positively by interconnection customers. Interconnection customers view the process for developing Tranche 1 as getting a good amount of transmission built and considering a variety of needs, including regional upgrades, when selecting the projects. For example, the LRTP considers project benefits related to the "potential economic value unlocked by the availability of least-cost resources across the footprint due to increase in transfer capacity."[116] In addition, LRTP projects will be added into future interconnection studies before they are completed, which will accelerate the impact of the LRTP on interconnection studies.

While a hopeful attitude prevails, some note that it is hard to quantify any effect on the interconnection queue because the queue is so large that model results are not affected much by the planned projects. Furthermore, because the new lines are at a high voltage, the queue is now being assigned the costs of building lower voltage facilities to support direct interconnection.

One interconnection customer flagged the concern that MISO-South's renewable boom might not align with MISO Tranches 3 and 4 in the LRTP because the projects in the queue are far ahead of the planning process.

---

114 Americans for a Clean Energy Grid (ACEG), *Transmission Planning and Development Regional Report Card (June 2023), p. 28.*

115 Interviews zb, zf, zg, zh, zj, zm, zn; project team contribution.

116 MISO, *LRTP Tranche 1 Portfolio Detailed Business Case* (June 25, 2022), p. 28.

PJM: Just starting to develop a forward-looking process[117]

Views of PJM's transmission planning process are the inverse of those for MISO. On the one hand, an interconnection customer comments that PJM must be doing something right because congestion is not as big of a concern in its market. Another interconnection customer remarks that getting a good interconnection agreement requires luck and patience.

But for the most part, interconnection customers view PJM as not having a forward-looking transmission planning process that identifies upgrades required to support the addition of new resources.[118] Perhaps PJM's lack of congestion is coming to an end, one interconnection customer speculates, because PJM's historically robust transmission system is at the point of hitting saturation and the planning process is unprepared to respond.

Until recently, interconnection customers viewed PJM's planning process as ignoring generation additions. However, PJM's 2022 regional transmission expansion plan updates its generator deliverability test and considers a forecast of "resource expansion and deactivation."[119] PJM also completed the first State Agreement Approach (SAA) process in 2022 to identify network upgrades for accommodating 7,500 MW of offshore wind in New Jersey. In addition, PJM is finalizing its approach for its Long-Term Regional Transmission Planning (LTRTP) process. However, it is not clear whether PJM's new approach will result in proactive development of new transmission capacity to enable future generator interconnection.

NYISO: New York beginning to prepare for clean energy future[120]

In its Public Policy Transmission Planning Process (PPTPP), NYISO has developed several transmission lines intended to reduce congestion between upstate renewable generation and downstate demand as well as to prepare the system for offshore wind capacity. In coordination with the Public Service Commission, NYISO added three upstate lines, completed a first planning process for interconnecting offshore wind into Long Island, and is starting a process for interconnecting offshore wind into New York City.

Although NYISO is currently developing its first set of comprehensive Policy Cases for their economic planning studies to achieve future policy goals, to date NYISO's economic planning framework has identified little to no transmission capacity upgrades. In addition, one interconnection customer raised concern that the recently implemented changes to the Local Transmission Planning Process in New York resulted in significant upgrades for a relatively small amount of capacity and so may not result in much improvement.

ISO-NE: Planning activities have not yet initiated transmission upgrade projects[121]

Although ISO-NE has relatively low congestion on its system, the ISO-NE system has limited headroom to interconnect resources in high quality renewable energy regions (such as Maine

117 Interviews zf, zg, zh, zj, zm, zn.

118 Note that PJM is currently in the process of developing a more proactive forward-looking planning process, the Long-Term Regional Transmission Planning process, but has yet to finalize the details of its approach or put it into practice.

119 PJM, *2022 Regional Transmission Expansion Plan* (March 14, 2023), pp. 11, 19.

120 Interview zh; project team contribution.

121 Interview zh; project team contribution

or southeast Massachusetts) and its transmission planning process has not resulted in any new transmission projects intended to support new generator interconnection. New resources in ISO-NE's planning studies are limited to those that have already cleared ISO-NE's 3-year-ahead Forward Capacity Market, limiting the scope of resources considered in its planning process.

At the urging of the New England states, ISO-NE just completed its first longer-term transmission planning process that identifies the need for upgrades to accommodate new generation resources that meet state goals. However, ISO-NE has not finalized its approach for selecting and approving lines for construction or its cost allocation of those projects across ISO-NE states.

SPP: Underbuilt transmission system with modest prospects for improvement[122]

SPP's transmission system was described by one interconnection customer as so under-built that any project is going to trigger a lot of network upgrades. This appears to be acknowledged by SPP in a 2023 report in which it states that its current transmission upgrade portfolio "was heavily driven by additional renewable generation, which has been historically under-forecasted."[123] SPP's base forecast includes the addition of roughly 12 GW (nameplate) of solar, wind and storage resources between years 5 and 10 in its integrated transmission plan.[124]

SPP's work with MISO on the Joint Targeted Interconnection Queue (JTIQ) is viewed as a promising first step, with an investment of $1.9 billion in five major projects.[125] However, even though some steps have been taken to reflect generator interconnection requirements in SPP's integrated transmission planning process, interconnection customers view the projects in SPP's $0.7 billion 2023 Integrated Transmission Plan as focusing on existing congestion rather than generator interconnection.

122 Interviews zf, zg, zh, zm, zp.
123 SPP, *2023 Integrated Transmission Planning Assessment Report (November 20, 2023), v. 1.0, p. 2.*
124 SPP, *2023 Integrated Transmission Planning Assessment Report (November 20, 2023), v. 1.0, p. 23*
125 MISO, *JTIQ Update and Next Steps, presentation to Planning Advisory Committee (November 15, 2023), p. 4.*

ERCOT: CREZ is ancient history[126]

While the large-scale Competitive Renewable Energy Zone (CREZ) transmission buildout earned national recognition as a forward-looking plan, interconnection customers see that kind of thinking as firmly in the past for ERCOT, which has approved only two transmission lines justified on economic benefits in the past decade.[127] In the view of interconnection customers, ERCOT's planning process does not even attempt to create upgrades that support interconnection of new generation. Instead, it is focused on alleviating congestion affecting load.

The interconnection customers' view is supported by the practices used in ERCOT's Regional Transmission Plan, which only considers generation from future projects that have a signed interconnection agreement or similar level of confirmation.[128] While ERCOT's Long-Term System Assessment does consider future generation needs, it does not result in proposed transmission upgrades that are considered in the Regional Transmission Plan process.[129]

In the opinion of interconnection customers, ERCOT needs multiple "CREZs" to bring new supply online.

126 Interviews zg, zh, zm.

127 Americans for a Clean Energy Grid, *Transmission Planning and Development Regional Report Card (June 2023), p. 49.*

128 ERCOT, *2022 Regional Transmission Plan Scope and Process (2022), Version 2.0, Section 3.2.1, p. 5; ERCOT Planning Guide (April 1, 2023), Section 6.9(1).*

129 Americans for a Clean Energy Grid, *Transmission Planning and Development Regional Report Card (June 2023), p. 50.*

6 APPENDIX
Interconnection Customer Assessments of Interconnection Timeline and Costs

Grid Strategies and The Brattle Group interviewed twelve generation developers and engineering firms who actively participate in multiple Regions' interconnection processes. The interviews were conducted with the following firms, and the number of participants in interviews varied from one to as many as five staff members.

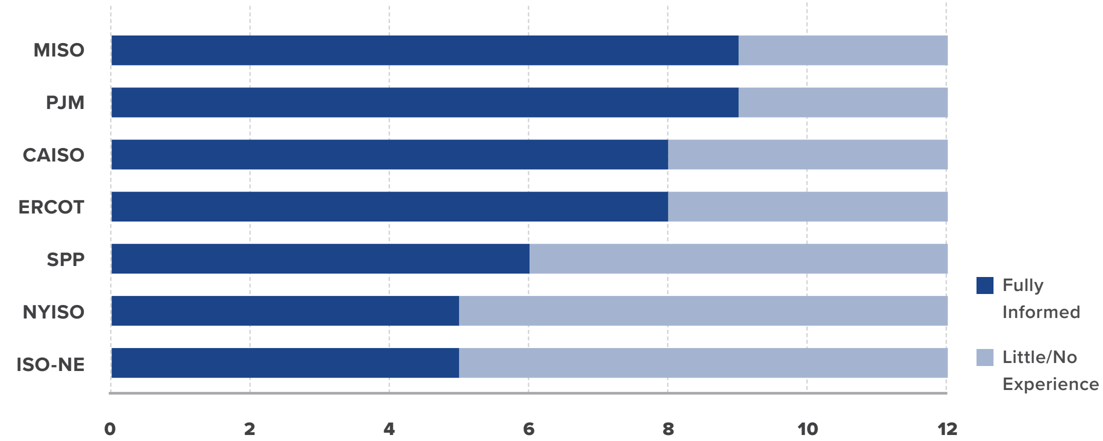
- AES Corporation
- Apex Clean Energy
- Clearway Energy Group LLC
- Cypress Creek Renewables, LLC
- EDF Renewables North America
- Electric Power Engineers, LLC
- GridStor
- Longroad Energy Holdings, LLC
- MN8 Energy
- New Leaf Energy, Inc.
- Savion, LLC
- Vestas

Each of the twelve interconnection customers interviewed for the scorecard was assigned a random two-letter code to provide anonymity.

No interviews covered every Region. In some interviews, interconnection customers focused on just two or three Regions. In other interviews, as many as five Regions were discussed in detail. As shown in interconnection customers' response to a pre-survey question in Figure 11, each of the Regions was familiar to at least 45% of the interconnection customers interviewed.[130] Interview participants were highly experienced, often with over a decade of relevant experience working in multiple Regions.

130 Because some interviews were attended by more than one staff member of the firm, the survey response (completed by a single staff member) sometimes underestimates the scope of participants' experience.

FIGURE 11 | Interconnection Customer Self-Assessment of Relative Familiarity with Each Region



During each interview, participants were asked to "rank" the Regions that they were familiar with according to their own views of interconnection timeline and costs. These rankings were often accompanied by significant context. For example, an interconnection customer might state that one Region was much, much better than any others or might state that two Regions were approximately equal. Much of this commentary is captured in the narrative report.

In order to incorporate this feedback into the scorecard grades, Grid Strategies adapted the rankings provided by each interconnection customer into a numerical scoring system and subjectively determined a consensus score, as shown in Table 14 and Table 15. In a few cases, the interview participants did not provide a clear ranking during the interview and thus those reports remain incomplete.

TABLE 14 | Amount and Predictability/Consistency of Time in Queue, Rankings from Interviews

Interview	CAISO	ERCOT	ISO-NE	MISO	NYISO	PJM	SPP	Other[131]
zb	4	1		4		5	3	
zc								
zd		1	3	5	4	4		2
zf		1		3		5	3	
zg		1		3	4	5	3	
zh	3	1			4	5		
zj				3		3	3	
zk	3		3		3			
zm	3	1		4		5	4	
zn	3			4		5		
zp	3			4				4
zr	2	1	1	4		3	3	
Consensus	3	1	2	4	4	5	3	n/a

TABLE 15 | Reasonableness and Predictability/Consistency of Interconnection Cost Estimates, Rankings from Interviews

Interview	CAISO	ERCOT	ISO-NE	MISO	NYISO	PJM	SPP	Other
zb	2	1		4		4	4	
zc								
zd		2	2	2	2	4		
zf								
zg		1		5	2	2	5	
zh	1	1			2	5		
zj				2		2	2	
zk	2		5		4			
zm	3	1		4		3	4	
zn	1			3				
zp	4	4		5				3
zr								
Consensus	2	1	3	3	3	3	4	n/a

131 The scorecard will not score non-ISO/RTO transmission providers ("other"). Presented for summary purposes.

Grid Strategies

gridstrategiesllc.com

info@gridstrategiesllc.com

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.

Based in the Washington DC area, the firm is actively engaged with the Federal Energy Regulatory Commission, Department of Energy, state Public Utility Commissions, Regional Transmission Organizations, the North American Electric Reliability Corporation, Congressional committees, the administration, and various stakeholders.

Brattle

brattle.com

The Brattle Group answers complex economic, finance, and regulatory questions for corporations, law firms, and governments around the world. We are distinguished by the clarity of our insights and the credibility of our experts, which include leading international academics and industry specialists. Brattle has 500 talented professionals across North America, Europe, and Asia-Pacific.