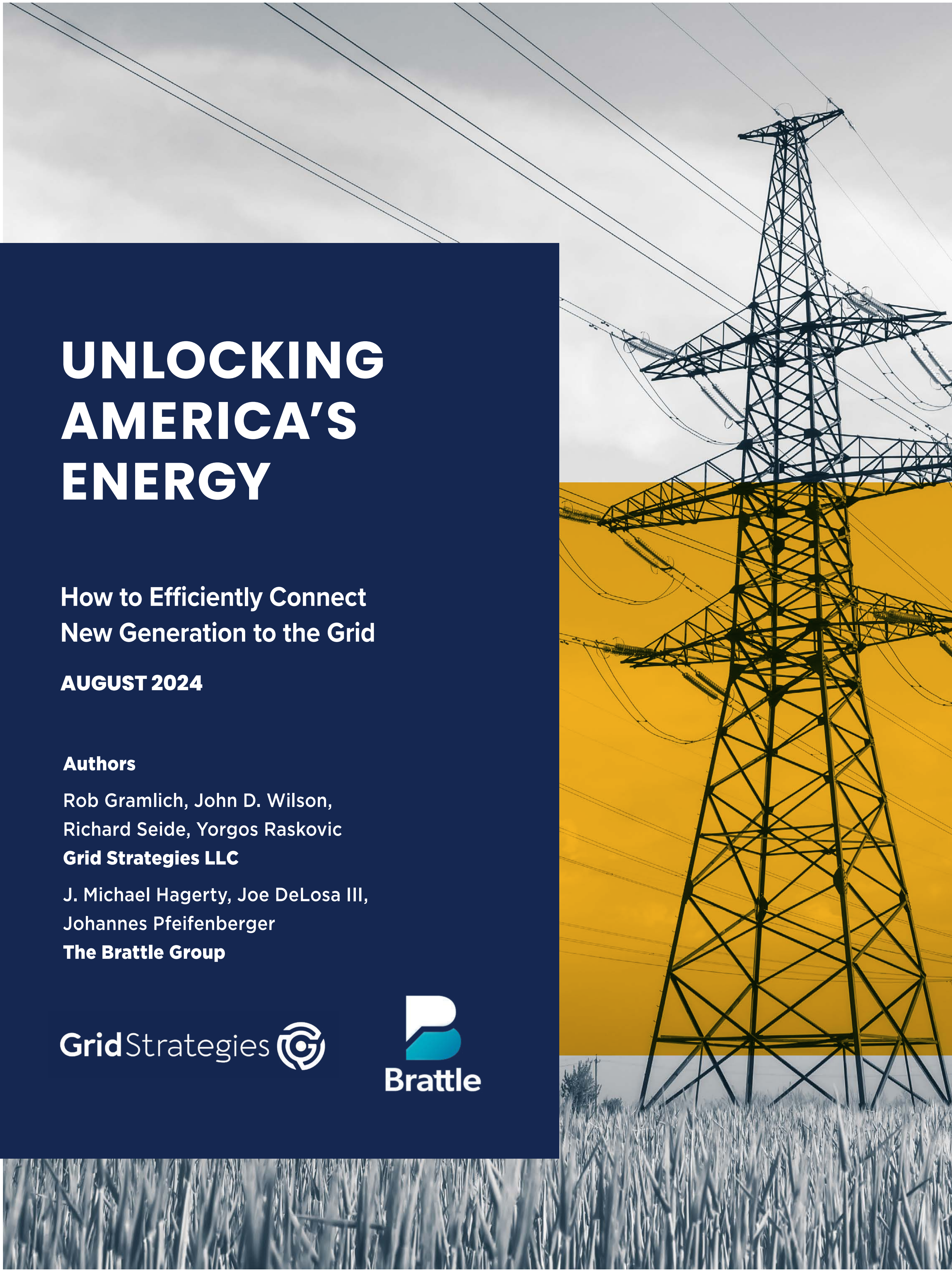


# UNLOCKING AMERICA'S ENERGY

## How to Efficiently Connect New Generation to the Grid

**AUGUST 2024**

**Authors**

Rob Gramlich, John D. Wilson, Richard Seide, Yorgos Raskovic
**Grid Strategies LLC**

J. Michael Hagerty, Joe DeLosa III, Johannes Pfeifenberger
**The Brattle Group**

GridStrategies

Brattle

## Acknowledgements

This project was funded by **Advanced Energy Institute** and **Solar and Storage Industries Institute**, with support from **Clean Energy Buyers Association**

Technical review was provided by:

Melissa Alfano
David Gahl
**Solar and Storage Industries Institute**

Jay Carrière
**NextEra Energy Resources**

Matthew Crosby
**Cypress Creek Renewables**

Kathryn Cox-Arslan
Liz Delaney
Brian Korpics
Adam Stern
**New Leaf Energy**

Regan Fink
Josh Grindeland
Chris Stolz
Brett White
**Pine Gate Renewables**

Alex Lawton
Caitlin Marquis
**Advanced Energy United**

John Miller
Hannah Muller
**Clearway Energy Group**

Mona Tierney-Lloyd
**Enel**

Brendan Endicott
Bridget Sparks
**AES**

Eli Asher
**LineVision**

David Mindham
**EDP Renewables**

Rich Glick
Pamela Quinlan
Liz Salerno
**GQS New Energy Strategies**


# CONTENTS

# EXECUTIVE SUMMARY

## Consumer demand for power is driving the need for a faster and more certain process for connecting new generation

With generator retirements outpacing the addition of new, cost-effective generation and storage resources and electricity demand soaring from new data centers and domestic manufacturing, keeping the electric power grid reliable and affordable has become a critical challenge for the nation. Meeting this challenge will require a timely and efficient approval process for connecting new electricity generators to the grid.

However, this approval process, known as "generator interconnection," has become a major barrier in recent years. The surge of generator interconnection requests has overwhelmed existing processes, causing major delays and producing an unprecedented backlog. In many cases, the total capacity of interconnection requests submitted in a single interconnection "queue" cycle exceeds the total regional peak load, resulting in impractical engineering studies with unrealistic results, delaying processes and creating cost and schedule uncertainty in the development of new generation resources.

## Inefficient interconnection policy raises consumer costs, creates reliability risks

The inability to complete the interconnection study process and build necessary transmission facilities in a timely manner introduces challenges in new generation resource development and creates costs that are ultimately passed on to consumers. Developers currently face cost and schedule uncertainty due to the complexity and lack of transparency of existing processes and limited options for managing associated risks. Without opportunities to efficiently bring cost-effective new generation online, customers of all kinds — homes, businesses, new data centers, manufacturing

**Without opportunities to efficiently bring cost-effective new generation online, customers of all kinds – homes, businesses, new data centers, manufacturing facilities, and others – will lack access to available lower cost generation resources and pay the resulting higher costs.**

facilities, and others — will lack access to available lower cost generation resources and pay the resulting higher costs.

Reliability and affordability are twin objectives of regulatory policy, and both are at risk if new supply cannot meet rising demand. If new generation resources cannot connect quickly enough, the grid may risk having insufficient capacity to meet demand while maintaining required margins of backup generation. Already, some grid operators are turning to inefficient solutions to ensure adequate supplies of power, such as paying premiums to retiring generators to stay online or running emergency procurements. By reforming the interconnection process to bring new generators online more quickly and cost-effectively, consumers can be spared these kinds of expensive, ad hoc responses to reliability concerns.

Affordability in electricity markets also depends on robust competition amongst existing and new generators. Slow and unworkable interconnection processes reduce competition by creating unreasonably high barriers to entry for new generation resources, often requiring uneconomic, out-of-market actions to prevent retirements.

With the power sector facing significant load growth and the prospect for rapid development of new, cost-effective generation resources, now is the time to continue advancing generator interconnection process reforms to ensure streamlined and expedited additions of these resources.

## FERC's Order No. 2023 is helpful, but additional reforms are urgently needed

Transmission providers—the entities responsible for administering the interconnection process—were initially slow to respond to the increased volume of new resources entering interconnection queues, resulting in significant interconnection backlogs. The *Generator Interconnection Scorecard* released in February 2024 assessed the current state of interconnection processes and gave five regional transmission operators low or nearly failing grades, highlighting the inefficiencies in their processes.[1]

**TABLE 1** | 2024 Generator Interconnection Scorecard Grades[2]

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

1 John D. Wilson, Richard Seide, Rob Gramlich and J. Michael Hagerty, *Generator Interconnection Scorecard: Ranking Interconnection Outcomes and Processes of the Seven U.S. Regional Transmission System Operators* (February 2024), Grid Strategies LLC and Brattle Group. Hereafter, "Interconnection Scorecard."

2 Interconnection Scorecard, p.5

In response to these challenges, the Federal Energy Regulatory Commission (FERC) and the transmission providers have recently been pursuing and implementing reforms to improve the generator interconnection process. In July 2023, FERC Order No. 2023 adopted reforms "raising the floor" for interconnection queue processes by moving all transmission providers to a cluster-based study process (i.e., studying all requests in a cycle together) and increasing readiness requirements through a first-ready, first-served approach to studying new generators (among other reforms). In May 2024, FERC Order No. 1920 adopted long-term transmission planning reforms that include a requirement to proactively consider future generation interconnection needs. FERC recognized in these orders that the problems with generator interconnection and related transmission planning practices over the past several years are structural, relying on outdated processes developed over 20 years ago for a very different set of needs.

FERC's orders occurred in the context of significant ongoing reform efforts by the six FERC-jurisdictional regional grid operators (collectively, the "Regions": CAISO, ISO-NE, MISO, NYISO, PJM, and SPP) and several other transmission providers (e.g., Duke Energy, Bonneville Power Authority, and Xcel Colorado).[3] Many transmission providers moved to a cluster study process in advance of Order No. 2023, and a few have developed proposals that go well beyond the requirements of Order No. 2023. Even ERCOT, which is not subject to FERC jurisdiction and received a passing grade in the Scorecard, is pursuing its own interconnection reform.

While FERC and transmission providers are making strides to improve the generator interconnection process, not all pressing issues have been addressed. For example, most transmission providers do not actively integrate interconnection studies with long-term, proactive transmission planning, instead relying on an inefficient, piecemeal approach to expanding the grid. Developers are still exposed to significant cost and schedule uncertainty at each stage of the interconnection study process, from queue entry through signing an interconnection agreement; this cost and schedule risk translates to higher power prices for consumers. Meanwhile, limited attention has been paid to addressing the significant delays occurring during the construction phase of grid upgrades (i.e., after an interconnection agreement is signed and upgrades are approved). Some of these added delays are driven by inefficient transmission owner practices for design and construction of interconnection facilities. All told, these challenges significantly raise consumer costs while delaying entry of new resources and put system reliability at risk.

## A vision for an efficient interconnection process

Given these developments, we identify the urgent need for additional reform across many aspects of the generator interconnection process to ensure access to new, cost-effective generation and storage in a timely manner while maintaining grid reliability in the face of rapidly changing supply and demand fundamentals.[4] To this end, the additional generator

3 California Independent System Operator (CAISO), Independent System Operator of New England (ISO-NE), Midcontinent Independent System Operator (MISO), New York Independent System Operator (NYISO), PJM Regional Transmission Organization, and Southwest Power Pool Regional Transmission Organization (SPP). Henceforth, "Regions" refers to these six regional transmission organizations (RTOs) and independent system operators (ISOs) as well as, in context, the Electric Reliability Council of Texas (ERCOT). "Transmission owners" refers to any company or organization that owns and constructs transmission facilities. "Transmission providers" refers to the Regions and transmission owners collectively.

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

interconnection reforms should advance three goals:

- **Cost Certainty and Transparency:** Generator interconnection costs, including the costs of needed transmission upgrades, should be certain enough to enable a manageable process for both transmission providers and generators seeking to interconnect (also known as interconnection customers). Improved cost certainty will help reduce the volume of queue submissions and withdrawals to more realistic levels, enhancing queue efficiency while reducing costs borne by consumers.
- **Speed and Schedule Certainty:** The generator interconnection process should move as quickly as feasible, considering state-of-the-art interconnection request processing (including automation), interconnection study methods, and construction management practices. Interconnection customers should have a high degree of confidence that transmission providers and owners will meet key milestones in all phases of the interconnection and upgrade construction process. Improving process timelines is essential for timely delivery of new generation resources to meet reliability needs and deliver cost-effective power to meet consumer demand.
- **Nondiscrimination:** No interconnection customer should face unreasonable barriers to competitive entry into electricity markets. The Federal Power Act (FPA) requires that the resulting rates, terms, and conditions of interconnection service must be just, reasonable, and not unduly discriminatory or preferential. A level playing field that provides similarly situated interconnection customers equal opportunities for adding new generation resources to the grid ultimately benefits consumers through increased competition and access to more cost-effective power.

# THE STAGES OF INTERCONNECTION

Pre-Interconnection → Interconnection Application → Interconnection Studies & Interconnection Agreement → Network Upgrade Construction → Commercial Operation

## CURRENT PROCESS (ORDER NO. 2023-COMPLIANT)

*Level of risk for interconnection customers does not align with degree of cost and schedule certainty*

| Pre-Interconnection | Interconnection Application | Interconnection Studies & Interconnection Agreement | Network Upgrade Construction | Commercial Operation |
|---|---|---|---|---|
| Lack of actionable information about transmission system headroom due to uncertain costs, study delays, and construction backlog | Projects pay to enter queue but receive little cost or schedule certainty<br>Limited information, not updated or reliable<br>Managing entries with queue caps may not prioritize "most ready" projects | High queue volumes lead to ambiguous results that delay withdrawals<br>Studies progress slowly, restudies common<br>Studies identify deep network upgrades<br>Costs and timelines uncertain | Cost increases and delays outside of developers' control with limited visibility<br>Insufficient proactive solutions to supply chain bottlenecks | Consumer costs increased due to process uncertainty and delays<br>Potential for reliability to be threatened due to lack of sufficient new resources |

## EFFICIENT INTERCONNECTION PROCESS

*Level of risk for interconnection customers corresponds to degree of cost and schedule certainty*

| Pre-Interconnection | Interconnection Application | Interconnection Studies & Interconnection Agreement | Network Upgrade Construction | Commercial Operation |
|---|---|---|---|---|
| Proactive planning to ensure transmission grid can accommodate known amount of new generation at a known cost<br>Existing and planned available headroom identified based on recent planning and interconnection studies | High fee to enter based on cost to increase planned interconnection capacity, in exchange for cost and schedule certainty<br>Transparent, timely, and actionable upfront information guides applications | Most projects move through fast-track processes, do not encounter surprise costs or delays and fewer withdraw<br>Competition for available headroom resolved through "most ready" scoring<br>Study results are fast, predictable, and replicable due to limited scope (focused on necessary upgrades for level of service requested), expanded use of cost-effective non-wire solutions, and deployment of automation | Transmission providers meet construction deadlines and budgets<br>Interconnection customers have visibility and recourse in the case of delays or cost increases outside their control | Generators efficiently come online as needed to deliver cost-effective, reliable power to consumers |

To meet those goals, this report's recommendations are organized around four key themes for reforming the interconnection process, targeting different aspects of the interconnection process. **Our recommendations should be considered and implemented together as a package to achieve the interconnection process goals.**

- **REFORM 1 | *Adopt an interconnection entry fee for proactively planned capacity***, provides interconnection customers significant interconnection cost certainty and addresses cost allocation of the upgrades identified through proactive planning processes. This reform allows projects to move forward with upfront certainty by specifying in advance the cost information in exchange for taking on some of the cost of planned transmission buildout.
- **REFORM 2 | *Implement a fast-track process to utilize existing and already-planned interconnection capacity***, implements an efficient process to quickly utilize existing and planned system capacity. In combination with Reform 1, these reforms create a fast-track process that opens up available transmission headroom for full utilization and prioritizes its use by "most ready" generator projects.
- **REFORM 3 | *Optimize the interconnection study process***, targets improvements to the interconnection study process to increase the system headroom considered to be "available" for interconnecting new resources through existing and new fast-track processes. It also identifies reforms necessary to make the study process more efficient. In combination with Reforms 1 and 2, interconnection requests should proceed through the study process more quickly.
- **REFORM 4 | *Speed up the transmission construction backlog***, addresses growing constraints to constructing network upgrades needed to bring new resources online after completing the interconnection study process.

Although not the focus of this report, proactive transmission planning is an essential element to improving the interconnection process. As noted throughout the report, the recommended interconnection reforms will be greatly enhanced by (and rely on) transmission upgrades identified through long-term proactive, multi-value planning processes. Several transmission providers are already implementing proactive planning, while others are in the process of developing long-term planning processes to comply with FERC Order No. 1920.

**REFORM 1**

**CERTAINTY** | Adopt an interconnection entry fee for proactively planned capacity.

## ENTRY FEE APPROACH

**INTERCONNECTION QUEUE PROCESS**
UNDER ORDER NO. 2023

**PRE-QUEUE**
Interconnection customer has **no information** about costs prior to queue entry

**CLUSTER STUDY**
Interconnection customer sees **first** cost estimate, which is often high

**CLUSTER RE-STUDY**

**FACILITIES STUDY**
Cost estimates **continue to change** based on project withdrawals, final local and grid upgrade cost estimates listed in interconnection contract

**CONSTRUCTION**
List of local and grid upgrades, and costs, agreed-to in signed contract **can still change**

**INTERCONNECTION QUEUE PROCESS**
ENTRY FEE MODEL

**PROACTIVE PLANNING**
Transmission provider conducts proactive planning including interconnection forecast

**ENTRY FEE**
Transmission provider **sets fee** based on each zone's planned interconnection capacity

**ENTER FAST TRACK**
Grid upgrades are already planned, so interconnection customers that pay entry fee are **fast-tracked to facilities study**

**FACILITIES STUDY**
Interconnection customer pays additional forecast cost of local network upgrades

**CONSTRUCTION**
Interconnection customer pays a single "true-up" to cover limited cost escalation (e.g., inflation)

Through a well-designed "entry fee" approach, interconnection costs are set prior to the interconnection process for accessing system capability proactively developed through a long-term, multi-driver, and scenario-based planning process that accounts for projected new generator interconnection needs. Generators with ready-to-develop projects compete to gain access to the amount of proactively planned system capacity based on their willingness to pay the posted entry fee and reasonable exit penalties (as applicable). Transmission providers would subsequently confirm through a streamlined process, such as the "fast-track" process proposed in Reform 2, the reliability of specific interconnection requests and identify any local upgrades not addressed in the proactive planning process.

Increasing cost certainty through an entry fee approach for proactively planned interconnection capacity would remove the incentive to use the interconnection study process as a cost-discovery tool for specific locations and reduce the cost risks of the interconnection study process for interconnection customers. Generators would assume known financial and development risks that match the higher level of cost certainty provided by the proactively planned interconnection capability and streamlined interconnection process for accessing it. Such a process would naturally reduce interconnection queue volumes, unburdening queues from the structural problems plaguing them today.

## REFORM 2

**UTILIZATION | Implement a fast-track process to utilize existing and already-planned interconnection capacity.**

There will be over 100 GW of aging existing generating resources projected to retire over the next decade as well as new capacity created for anticipated generator interconnection needs through proactive planning. Requiring resources that utilize available capacity to proceed through time-consuming cluster study processes designed to identify reliability needs and develop transmission solutions is unnecessary. Instead, transmission providers should significantly reduce interconnection timelines and provide greater schedule certainty by adopting interconnection processes that expedite interconnection requests that utilize existing and planned grid capacity ("headroom").

A fast-track process would allow transmission providers to quickly interconnect new resources at locations on the system with existing and planned headroom that do not require additional network upgrades. The sign of a well-functioning interconnection process would be one in which the majority of interconnection requests can move through a fast-track process, including the "entry fee" process for proactively planned grid capacity, and the cluster study process serves as a backstop for interconnection requests that exceed the currently available system capacity.

The "fast-track" process would screen whether interconnection requests result in no or only minimal adverse impacts on the system and allow those that pass the impact screen to advance on an expedited basis to the interconnection agreement phase of the process. Interconnection requests for which the screening analysis identified material adverse impacts would still need to go through the full interconnection study process to identify necessary upgrades.

To implement an effective fast-track interconnection process, we propose four specific reforms that are needed to efficiently utilize available or already-planned grid capacity:

**Reform 2A | Provide transparent, timely, and actionable information for interconnection customers to identify available or low-cost headroom.** Prior to submitting interconnection requests, project developers currently have limited insight into points of interconnection with available capacity to support their projects. Actionable information about locations on the grid with existing or planned capacity, based on recent transmission planning and interconnection studies, should be available to interconnection customers and updated regularly so that interconnection customers can request access to the fast-track process.

**The sign of a well-functioning interconnection process would be one in which the majority of interconnection requests can move through a fast-track process, including the "entry fee" process for proactively planned grid capacity, and the cluster study process serves as a backstop for interconnection requests that exceed the currently available system capacity.**

**Reform 2B | Create a fast-track process for locations with clearly defined existing or planned available capacity.** Once headroom is identified, interconnection customers with ready-to-develop projects should be able to request access to that capacity on an expedited basis. Transmission providers should offer a fast-track process that screens interconnection requests at locations with existing or planned capacity to verify that the new resource would result in no or only minimal adverse impacts on the system. If confirmed, the requests would advance to the interconnection agreement phase; if not, the requests would enter the standard interconnection queue.

**Reform 2C | Create or update fast-track processes for the efficient replacement of existing plants.** Opening up opportunities for low-cost interconnection at the sites of retiring fossil-fired and nuclear resources through a fast-track process is also critical to utilizing available capacity. Many transmission providers already provide such an option, but not all, and existing processes are often needlessly inefficient. Existing resources with interconnection capability should be able to share or transfer headroom to new resources. Requests to utilize existing capabilities that do not exceed existing capability should be presumed to have no material adverse impact but be confirmed through a screening process.

**Reform 2D | Prioritize "most ready" interconnection requests for available headroom.** The fast-track processes should be paired with an approach to prioritize access to limited existing or planned available capacity by identifying the "most ready" projects that are likely to be built expeditiously following the execution of an interconnection agreement. FERC should maintain the readiness requirements of Order No. 2023 to screen out the least-ready projects and, in addition, transmission providers should allow interconnection customers to compete for priority access to the available capacity, such as by implementing a "most-ready" scoring method.

## REFORM 3

### EFFICIENCY | Optimize the interconnection study process.

Order No. 2023 made significant progress towards reforming interconnection study processes, yet these processes remain unnecessarily complex, resource-intensive, and prone to delays. More fundamental reforms are needed to increase the amount of existing system capacity available for the fast-track process proposed in Reform 2 and to vastly increase the efficiency of interconnection study processes for resources that do not qualify for the fast-track process. These five recommended improvements should enable interconnection requests to proceed more efficiently through the interconnection study processes.

**Reform 3A | Identify only network upgrades that are consistent with the requested interconnection service level.** Interconnection studies currently trigger network upgrades that are not required to maintain system reliability given how system operators manage the grid in real-time, such as through market-based generation redispatch. Adopting practices to better align required upgrades with requested service levels, including both ERIS and NRIS, and to provide interconnection customers an attractive (non-firm) energy-only option will relieve interconnection customers (and ultimately electricity customers) of unnecessary costs, and enable more efficient interconnection of new resources.

**Reform 3B** | **Identify the most cost-effective solutions for resolving reliability violations.** Current practices that favor "traditional" solutions should be updated to allow for efficient solutions that enable increased utilization or low-cost expansion of the existing grid. Transmission providers should not just *consider* available traditional solutions, but also include well-tested and commercially available solutions that can rapidly expand available headroom on transmission systems. These options include use of simple remedial action schemes and grid-enhancing technologies.

**Reform 3C** | **More closely align data inputs, assumptions, and process timing between interconnection study processes of different local and regional scope.** In Order No. 2023, FERC did not address study alignment issues that create significant challenges for completing interconnection studies. Alignment is needed in two directions, (1) local-to-regional and (2) host system to affected system, so interconnection requests can be studied more efficiently and with less uncertainty to developers.

**Reform 3D** | **Use automation to expedite interconnection studies.** Transmission providers have recently demonstrated that automation can significantly expedite interconnection studies. To further increase process efficiency and reduce interconnection timelines, already-proven applications of interconnection study automation should be more broadly adopted and further applications of automation should be explored.

**Order No. 2023 made significant progress towards reforming interconnection study processes, yet these processes remain unnecessarily complex, resource-intensive, and prone to delays.**

**Reform 3E** | **Establish independent interconnection study monitors.** Many practices required or recommended by FERC (such as in

Order No. 2023) leave substantial flexibility or discretion to transmission providers, which leads to different and often incompatible study criteria and approaches. Independent interconnection study monitors are needed to avoid inefficiencies and adverse impacts associated with the complex technical details of interconnection studies and the flexibility and discretion that transmission providers exercise. The transparency that independent monitors can provide would inform process improvements by the transmission providers or targeted areas for future regulatory action by FERC.

## REFORM 4

### CONSTRUCTION | Speed up the transmission construction backlog

Over the past few years, there have been increasing delays *after* the interconnection agreement has been signed. Much of the delay is beyond the developer's control. While network upgrade construction timelines are increasing across the industry, some transmission owners complete upgrade projects more quickly and with fewer delayed projects (or shorter delays) than other transmission owners, suggesting there is significant room for improvement. Looking across all transmission owners, the most convincing evidence for any confirmed cause of the transmission construction delays relates to supply chain constraints affecting key equipment for transmission upgrades.

**While network upgrade construction timelines are increasing across the industry, some transmission owners complete upgrade projects more quickly and with fewer delayed projects (or shorter delays) than other transmission owners, suggesting there is significant room for improvement.**

**Reform 4A | Improve reporting on the transmission project construction phase.** While supply chain constraints are a factor, the extent of their impact as well as other causes for the consistent increase in construction timelines are less well understood. To better understand the causes of the transmission construction backlog, FERC, the Regions, transmission owners, and state regulators should implement improved reporting on progress towards constructing new transmission facilities. These data will enable exploration of the portion of delays caused by various issues, including (1) project management prioritization by transmission owners, (2) other construction issues including supply-chain availability and limited outage windows, and (3) voluntary delays of in-service dates by interconnection customers.

**Reform 4B | Industry and government collaboration to reduce supply chain bottlenecks.** To address supply chain constraints, we recommend a cooperative procurement program. Such a program could provide equipment manufacturers with the assurance needed to expand factories. This can best be accomplished through voluntary action by transmission owners, facilitated by federal assistance with financing.

## Priority Reforms for an Efficient Interconnection Process

| Process Phase | Reform Number | Reform Proposal | Contribution to an Efficient Interconnection Process |
|---|---|---|---|
| **Proactive Interconnection Capacity Planning Phase** | **REFORM 1** | Certainty: Adopt an interconnection entry fee for proactively planned capacity. | This reform introduces cost certainty and addresses cost allocation, allowing projects to move forward with upfront cost information in exchange for taking on some of the cost of planned transmission buildout. |
| **Pre-Request and Interconnection Study Phases** | **REFORM 2** | Utilization: Implement a fast-track process to utilize existing and already-planned interconnection capacity. | These reforms implement an efficient process to quickly utilize existing and planned system capacity. In combination with Reform 1, they create a fast-track process that opens up available transmission headroom for full utilization and prioritizes its use by "most ready" generator projects. |
| | 2A | Provide transparent, timely, and actionable information for interconnection customers to identify available or low-cost headroom. | |
| | 2B | Create a fast-track process for locations with clearly defined existing or planned available capacity. | |
| | 2C | Create or update fast-track processes for the efficient replacement of existing plants. | |
| | 2D | Prioritize "most ready" interconnection requests for available headroom. | |
| | **REFORM 3** | Efficiency: Optimize the interconnection study process. | These reforms increase the system headroom that is considered "available" and make the study process more efficient. In combination with Reforms 1 and 2, these reforms should enable interconnection requests to proceed through the study phase more quickly. |
| | 3A | Identify only network upgrades that are consistent with the requested interconnection service level. | |
| | 3B | Identify the most cost-effective solutions for resolving reliability violations. | |
| | 3C | More closely align data inputs, assumptions, and process timing between interconnection study processes of different local and regional scope. | |
| | 3D | Use automation to expedite interconnection studies. | |
| | 3E | Establish independent interconnection study monitors. | |
| **Construction Phase** | **REFORM 4** | Construction: Speed up the transmission construction backlog. | These reforms address growing constraints to bringing new resources online after completing the study process. They deliver the benefits of Reforms 1-3 to consumers more quickly and cost-effectively. |
| | 4-A | Improve reporting on the transmission project construction phase. | |
| | 4-B | Industry and government collaboration to reduce supply chain bottlenecks. | |

# INTRODUCTION

**Interconnection has become one of the primary constraints to adding new resources to the power system, resulting in 2,600 GW of resources that are "stuck" in interconnection queues across the country.**

### *State of Play*

As often noted in the industry, including by the Department of Energy's *Transmission Interconnection Roadmap*, known as the *i2X Report*, "Interconnection processes will need to evolve to handle [the rapid rise of interconnection requests] today and into the future, as policy and economic drivers continue to motivate significant resource development."[5] These drivers include growing electricity demand due principally to new large loads, electrification of the building and transportation sectors, evolving project economics, and state policies. 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 the *Generator Interconnection Scorecard* confirmed, progress towards completing those interconnections is slow, costly and uncertain — putting system reliability at risk.

Interconnection has become one of the primary constraints to adding new resources to the power system, resulting in 2,600 GW of resources that are "stuck" in interconnection queues across the country. FERC and the operators of transmission systems have recognized overlapping challenges limiting interconnection process throughput and have been implementing reforms that they hope will result in initial improvements to the process. Unfortunately, even if these initial reforms succeed, they are unlikely to be sufficient to meet the growing challenges.[6]

5 US Department of Energy, *Transmission Interconnection Roadmap* (April 2024), p. viii. Henceforth, "i2X Report."

6 A number of industry participants have discussed the need to improve generator interconnection over the last years, both leading up to and following Order 2023. For example: Energy Systems Integration Group, (2022), Summary of the Joint Generator Interconnection Workshop. Virtual workshop held by the Energy Systems Integration Group, North American Generator Forum, North American Electric Reliability Corporation, and Electric Power Research Institute,(August 9-11, 2022), Reston, VA.
Enel Green Power North America, Plugging In: A Roadmap for Modernizing & Integrating Interconnection and Transmission Planning,
Norris, Tyler H. Beyond Order 2023, Considerations on Deep Interconnection Reform, (August 2023), Duke University, Nicholas Institute for Energy, Environment & Sustainability.
Armstrong Les, Canaan Alexa, Knittel Christopher R., Metcalf Gilbert E. FERC Order 2023: Will it Unplug the Bottleneck?, (December 2023), MIT Center for Environmental and Energy Policy Research

Advanced Energy United and the Solar and Storage Industries Institute retained Grid Strategies and The Brattle Group to identify additional reforms that will be necessary to allow for new resources to more efficiently interconnect to the grid. We developed the reforms proposed in this report based on a set of goals for future interconnection processes, a review of recent FERC orders related to transmission planning and interconnection, and our review of alternative approaches proposed or employed in the U.S. and abroad.

In this section, we summarize the recent FERC actions and reforms being developed by transmission service providers and lay out the goals and methods that drive our proposed reforms, and then explain the proposed reforms. The key points of recent FERC actions are summarized here, with additional detail provided in Appendix 1.

### *Key FERC Orders*

- In 2018, FERC Order No. 845 introduced several important changes to improve the interconnection process. It allowed interconnection customers to request service below their full generating capacity, better integrated energy storage in the interconnection process, added surplus service and provisional service, improved timing and financial certainty for customers, and provided the option for customers to self-build upgrades. (See Appendix 1.1)
- In 2023, FERC Order No. 2023 required enhancements to the interconnection processes and agreements used by electric transmission providers to integrate new generating facilities into the existing transmission system. The reforms shifted to a "first-ready, first-served" cluster study process, required heatmaps that display available transmission capacity, set stricter financial readiness and site control requirements, and mandated firm deadlines and penalties for transmission providers that fail to complete interconnection studies on time. (See Appendix 1.2)
- In 2024, FERC Order No. 1920 updated requirements for long-term transmission planning to more proactively prepare the system for future needs, including the interconnection of new generation resources. These reforms require proactive multi-driver and multi-benefit long-term planning and that the transmission planning process consider interconnection-related transmission needs based on the queue or a history of network upgrades originally identified through the interconnection process. Order No. 1920 did not modify cost allocation for interconnection-related network upgrades, which maintains grid operator flexibility and enables a range of potential generator interconnection cost allocations, ranging from full participant-funding models to system-funding models that directly allocate costs to load. (See Appendix 1.3)

FERC recently issued several orders providing a faster track for the replacement of retired generation, as summarized in Appendix 1.4. Some regions are introducing new reforms to interconnection-related processes, and related proposals and orders are summarized in Appendix 2.

## Goals for Continued Interconnection Reform

This report's goals for continued interconnection reform are derived from FERC's responsibility under the Federal Power Act (FPA), as summarized in Appendix 1.6, to ensure that rates are just, reasonable, and not unduly discriminatory or preferential (in this report, "nondiscriminatory"). Future electricity rates can be lower if the interconnection process can bring low-cost generation online more quickly and cost-effectively than under current rules.

### *Cost Certainty and Transparency: Reduce uncertainty of interconnection costs for the ultimate benefit of consumers*

All systems will need new generation at some point and cost uncertainty translates into generation development costs that consumers will ultimately end up paying. Uncertainty in the generator interconnection process results from a variety of factors including the analytical difficulty of attributing shared network costs to individual generators with large volumes of generation, power flow modeling challenges, lack of ability to replicate the transmission provider's model, and engineering judgment on the part of the transmission provider which may be reasonable but is impossible to predict. Providing greater certainty can reduce new generation costs and delivered energy costs for consumers.

Interconnection customers have expressed greater concern over cost uncertainty than over the average level of the costs. Typically, the total costs do not become apparent until the end of the multi-year process.[7] When such cost uncertainty remains unresolved until the project is placed into service, there are a number of consequences:

- Uneconomic projects remain in the queue longer;
- Interconnection customers are incentivized to submit multiple requests, further driving up study costs and delaying interconnections, and further delaying grid access of beneficial generators;
- Generators incur higher financing costs due to increased project risk; and
- Generators delay contract negotiations with wholesale customers, resulting in suspensions of the construction process until generators firm up customer relationships.

Regarding this final point, if generators can offer reliable terms to wholesale customers early in the interconnection process, this increases the liquidity of the power market, lowering costs to end customers. Thus, the objectives of cost certainty for interconnection customers and lower costs for ratepaying consumers are closely interrelated.

**The objectives of cost certainty for interconnection customers and lower costs for ratepaying consumers are closely interrelated**

Furthermore, if interconnection customers cannot anticipate reasonable and consistent cost assignment practices, their decision to offer new resources into the generation market may be distorted, resulting in inefficient cost outcomes

7 Interconnection Scorecard, p. 54.

for consumers. Five Regions assign costs to interconnection customers using a participant-funding model in which interconnection customers provide funding for all assigned network upgrade costs. CAISO, ERCOT and other transmission providers use a system-funding model, in which those costs are initially funded by the interconnection customer but are then ultimately refunded, using funds collected from the system's customers.

Interconnection customers should be able to have confidence that transmission providers are reasonably assigning cost responsibility on the basis of cost-causation or benefits. Transmission providers should not assign network upgrade costs to projects with a marginal impact on system reliability or base those cost assignments on scenarios that rely on an improbable combination of project dispatch and system load.

***Speed and Schedule Certainty: A faster, more predictable interconnection and construction process***

Interconnection customers face lengthy and unpredictable schedules for network upgrades. The lack of information regarding available headroom and infrastructure at points of interconnection to the transmission system requires interconnection customers to use the time-consuming study process to obtain critical information, bogging down these processes with excessive volumes of interconnection requests. Construction processes often bring further delays due to both external factors—such as supply chain bottlenecks and land rights—and internal factors, such as the transmission owner's budget constraints or construction management practices. The lengthy and uncertain construction phase drives up financing costs, ultimately increasing costs for consumers.

***Nondiscrimination: Customers that are similarly situated should have equal access to interconnection service***

Throughout the interconnection process, there are points at which interconnection customers experience issues that may violate the FPA's protections against undue discrimination. Despite extensive rulemakings by FERC, for projects seeking to interconnect with transmission owned by a vertically integrated company, FERC has continued to raise concerns about the potential for the exercise of vertical market power, as discussed in Appendix 1.6. Any reform should ensure that similarly situated customers have equal access to interconnection service, while recognizing that there may be reasonable distinctions among classes of interconnection customers that could justify differing treatment.

## Further Opportunities for Reform

In addition to the reforms recommended in our report, transmission providers and stakeholders may consider pursuing further interconnection study process improvements. Our additional recommendations briefly summarized here include several steps to actively monitor and increase transparency of interconnection study and construction processes. Furthermore, there are opportunities for near-term reform that could be further investigated.

### *Active monitoring and process transparency*

Evidence discussed in the *Generator Interconnection Scorecard and this report points to a need to achieve greater transparency regarding interconnection opportunities and costs. Some of the areas where shortcomings in data could be immediately addressed include:*

- **Pre-request period:** Generation developers need basic technical information about potential points of interconnection, such as whether substations have open terminal bays or existing fiber connections.[8] Information outlining transmission owners' policies and practices regarding collecting and sharing such information proved difficult to obtain for this report.
- **Interconnection study process:** While transmission providers provide significant information about interconnection study queues, much relevant information is difficult to locate, verify, and compare on a consistent basis. Information from most non-RTO transmission owners is particularly scarce. Even for the Regions, estimates of queue study timelines and interconnection costs require tedious manual data collection from individual generation interconnection agreements.[9] It does not appear that any entity tracks status or outcomes of affected system studies.
- **Construction phase:** Even less information is available about the construction phase. The scarcity and inconsistency of data about transmission upgrades, including those directly related to interconnection requests, is documented in Appendix 3.

To develop compelling evidence to identify new reforms or fully develop other proposed changes in interconnection practices, we recommend that transmission providers supply transparent, timely, and actionable information for interconnection customers to identify POIs with available or low-cost capacity (Reform 2-A), creation of independent interconnection study monitors (Reform 3-C), and improved reporting on the construction phase (Reform 4-A). Implementing these recommendations will be an important step towards creating more actionable reform proposals.

### *Interconnection study and construction management practices*

In the course of our research, stakeholders shared several popular ideas for better practices by transmission providers, some of which are discussed in Appendix 4. An obstacle to fully investigating these practices is the need for internal performance, scheduling, and budget data that are deeply embedded within transmission providers and transmission owners. Reforms to improve access to these data are summarized above.

### *Continued improvement to provisional and limited service opportunities*

Even with improvements to the transmission construction process, some generators will be ready to come online before the grid is upgraded to fully accommodate their output in all scenarios. To enable early interconnection under provisional or limited service operating rules, interconnection customers need information from studies to make a commercial decision

8 Interconnection Scorecard, p. 40.

9 Joseph Rand et al., *Queued Up: 2024 Edition, Characteristics of Power Plants Seeking Transmission Interconnection as of the End of 2023*, Lawrence Berkeley National Laboratory (April 2024). Hereafter, "Queued Up 2024."

regarding whether expected revenues justify the increased curtailment risk of provisional service. This includes customer acceptance of network upgrades allocated retroactively which is a key tradeoff to this form of interconnection.

In Order No. 845, FERC required provisional interconnection service.[10] However, FERC did not adopt a *pro forma provisional interconnection study process or agreement.*[11] Provisional interconnection service is a temporary ERIS agreement that allows interconnection prior to the completion of all interconnection studies and construction of all required upgrade facilities.

As with other alternate interconnection service options, some transmission providers have made it more useful than others. In SPP's interconnection study process, all interconnection requests are studied for both NRIS and ERIS, including limited operation, which is defined as interconnection capacity available without system overloads, voltage violations, instabilities, or breaker over-duty prior to the in-service date of all identified upgrades."[12] Duke recently proposed to update its provisional service for application in its cluster study process.[13] Transmission providers should continue to consider best practices and enhancements for provisional or limited service.

### *Generator facility permitting and project finance*

Generation interconnection schedules and costs are widely understood to be affected by permitting of new generation facilities[14] and project finance.[15] Evidence discussed in this report points to each of these issues as impediments to reaching the goals of speed and lower/more certain costs. For example, developers report that projects are now facing higher interest rates and often contend with delays in closing financing. However, those activities require distinct treatment and expertise from the topics focused on in this report.

10 Order No. 845, para 5.

11 Order No. 845, para 444.

12 SPP, *Generator Interconnection Manual (DSIS Manual)* (August 2023)*, Version 2.0, pp. 5, 32.*

13 Duke Energy Progress and Duke Energy Carolinas, *Revisions to Attachment K to Joint OATT (LGIP/LGIA) for Provisional Interconnection Service* (June 28, 2024).

14 In 2021, the Sabin Center for Climate Change Law identified 103 local government policies to block or restrict renewable energy facilities and 165 contested renewable energy facilities. In 2024, those numbers had grown to 395 local- and 19 state-level restrictions, as well as 378 renewable energy projects that have encountered significant opposition. Matthew Eisenson et. al., *Opposition to Renewable Energy Facilities in the United States*, Columbia Law School, Sabin Center for Climate Change Law: 2021 Edition, p. 2; and 2024 Edition, p. 5.

15 According to Wood Mackenzie, renewable energy projects' high capital intensity and low returns place them at disproportionate risk in a higher interest rate economy. Wood Mackenzie, *Conflicts of Interest: The Cost of Investing in the Energy Transition in a High Interest-Rate Era* (April 2024), p. 5. According to ACORE, the tax equity market needs to triple to fully serve renewable energy developers. ACORE, *Expectations for Renewable Energy Finance in 2023-2026* (June 2023), p. 28.

**REFORM 1**

# CERTAINTY

*Adopt an interconnection entry fee for proactively planned capacity.*

An interconnection entry fee framework uses a pre-set interconnection price to provide interconnection customers cost certainty and allocates costs of planned transmission upgrades that enable interconnection to the new resources utilizing the planned headroom. By providing greater cost certainty for interconnection customers at attractive zones on the system, an entry fee framework should free the interconnection study process from being used as a cost-discovery tool.

**To provide cost certainty and efficiently connect funding from interconnection customers to help build planned transmission, we recommend that transmission providers adopt an entry fee pricing mechanism that represents a binding financial commitment between the interconnection customer and the transmission owner(s).**

With FERC's requirement of multi-value planning in Order No. 1920, it falls to the Regions and transmission owners to adequately plan the transmission network over the long-term for multiple purposes including providing consumer access to generation options. Proactive long-term, multi-driver planning for future system needs, including generator interconnection needs, is likely to result in lower total system costs, with shorter and more certain schedules for construction of the necessary transmission upgrades. To provide cost certainty and efficiently connect funding from interconnection customers to help build planned transmission, we recommend that transmission providers adopt an entry fee pricing mechanism that represents a binding financial commitment between the interconnection customer and the transmission owner(s).

Several Regions have taken steps to improve the certainty of interconnection costs, in part to avoid use of the interconnection study process as a cost-discovery tool. Where interconnection costs can be known up front, interconnection customers should be more certain that their requests will progress through the study process with fewer re-studies and other complications due to project withdrawals.

Named an “entry fee” approach by SPP, a pre-set interconnection price can be derived from the forecast cost of additional regional and sub-regional system capability that has been identified through proactive planning studies and will be built by transmission providers in advance of need.[16] Limited additional local upgrades may also be identified based on the specific location of the resource. This process informs interconnection customers of the full costs and timelines to interconnect.

Once interconnection customers file their requests for service, transmission providers should provide an expedited “fast-track” process for confirming reliability for specific interconnection requests, as proposed in Reform 2 below.

Generators with ready-to-develop projects would compete to gain access to the available system capacity based on their willingness to pay the posted entry fee and willingness to take on the risk of reasonable exit penalties (as applicable), greatly reducing developer risks of an uncertain interconnection queue process. In this way, generators would assume known financial and development risks that match the higher level of certainty provided by the proactively planned transmission capability and streamlined generator interconnection process for accessing it. Such a process should naturally reduce interconnection queue volumes to a realistic level, unburdening queues from the structural problems plaguing them today.

Such pricing proposals are being developed by SPP in its Consolidated Planning Process (CPP) reform proposal and by SPP and MISO in their Joint Targeted Interconnection Queue (JTIQ) process. In each of these cases, a simplified, pre-set price for interconnection maintains the Regions’ participant-funding model. For example, while retaining responsibilities for participant funding, SPP views the CPP Entry Fee model as potentially better aligned with the beneficiary-pays principle because it “would spread the cost of facilities over multiple clusters of customers, more appropriately ‘assigning’ costs to beneficiaries.”[17]

> **… while retaining responsibilities for participant funding, SPP views the CPP Entry Fee model as potentially better aligned with the beneficiary-pays principle because it “would spread the cost of facilities over multiple clusters of customers, more appropriately ‘assigning’ costs to beneficiaries.**

16 An entry fee is endorsed by Solar and Storage Industries Institute in: David Gahl, Melissa Alfano, and Tiana Elame, *Game Changing Interconnection Reform: Reshaping Transmission Planning and Realigning Incentives* (April 25, 2024), Solar and Storage Industries Institute.

17 SPP, *Entry Fee Framework – Policy Direction Recommendations* (April 16, 2024), p. 74. Henceforth, “SPP Entry Fee Framework.”

### Establishing the planning basis for an interconnection entry fee

Based on the limited experience with entry fee concepts, the key elements needed to enable an entry fee framework appear to be:

- Proactive planning of needed interconnection capacity,
- A cap on entry in a given interconnection process cycle (defined by planned available capacity in a particular region or zone), and
- Generator project readiness criteria to ensure that interconnection requests advance swiftly through study and construction phases.

The interconnection entry fee concept has been developed most fully in the U.S. by SPP in its Consolidated Planning Process proposal. Aspects of the concept have been demonstrated by Rte in France, in the MISO/SPP JTIQ process (which is still a work-in-progress), and the CAISO zonal approach. SPP's process that led to recommending an entry fee suggests that an entry fee may be a consequence of the assessment of generator interconnection needs by transmission providers in the Order No. 1920 long-term planning processes.[18] Transmission providers are expected to identify beneficial regional upgrades that reduce costs to ratepayers and support interconnection of cost-effective new resources, avoiding the need for higher cost, piecemeal upgrades identified through interconnection studies.

The transmission provider should define the entry fee by applying the "beneficiary pays" approach, which provides that the costs of projects identified in the long-range transmission planning process should be assigned to generators and wholesale customers based on the degree to which they benefit from (or cause) the projects.

Furthermore, by proactively planning for the capacity needed to interconnect anticipated new generation, transmission planners can substantially reduce the volume of interconnection requests that must be queued for cluster studies. In some cases, interconnection cluster studies have received total resource requests in excess of the total existing demand on the system. For example, MISO's 2022 study cycle included 171 GW of interconnection requests, exceeding its peak load of 120 GW by 51 GW. This scale of new capacity additions makes it technically infeasible to even complete studies for identifying required network upgrades. Under these conditions, where the cumulative capacity of interconnection requests to be studied exceeds the system's peak load, both interconnection customers and transmission providers recognize that the model results cannot be anything other than unrealistic.

Of the many examples of proactive, multi-value planning, the most sustained efforts have been demonstrated by CAISO and ERCOT), which each received the highest awarded grade of "B" in the *Transmission Planning and Development Regional Report Card.*[19] Another informative example is Duke Energy's local transmission planning process in the Carolinas, which has evolved from a near-term proactive, solar-focused buildout (known as the "Red Zone Expansion Plan") to the long-term, multi-value strategic transmission (MVST) process initiated this year.

---

18 FERC, *Order No. 1920: Building for the Future Through Electric Regional Transmission Planning and Cost Allocation* (May 13, 2024), para. 1107.

19 Americans for a Clean Energy Grid, *Transmission Planning and Development Regional Report Card* (June 2023), p. 5.

The opportunity for evaluation of interconnection resource needs through proactive planning to reduce costs is substantial. For example, PJM's conventional offshore wind interconnection study resulted in study costs of $236-415 per kW,[20] while a proactive transmission planning approach cost only $27 per KW.21 And SPP estimated that transmission projects with costs of $5.2 billion were expected to have benefits of $27.2 billion, "including increased wheeling revenues, reliability and resource adequacy, reduced transmission losses, and benefits associated with optimal wind development."22 Concrete demonstration of the benefits of an integrated planning approach has occurred in MISO's multi-value transmission plans, in the joint MISO/SPP JTIQ process, as well as the New Jersey State Agreement Approach described above and other regional planning processes. FERC left transmission providers with significant responsibility to achieve these savings, giving them substantial discretion in pursuing the integration of interconnection studies and long-term transmission planning.

### *Generation zones*

Once transmission providers identify beneficial regional upgrades that reduce costs to ratepayers and support interconnection of cost-effective new resources, they are likely to assign each upgrade to a generation zone. Generation zones are usually understood to be areas with land availability and cost attractiveness, likelihood of community acceptance, and other factors that are likely to affect the location of future generation. FERC considered requiring the identification of generation zones in Order No. 1920 but decided not to require it for all transmission providers. Many transmission planning processes have incorporated the concept of generation zones either explicitly or implicitly.

An example of detailed development of generation zones is the Illinois Renewable Energy Access Plan. The plan used four criteria to characterize renewable energy zones: resource potential (including demonstrated developer interest), current land uses, environmental justice communities, and locations of fossil retirements.[23] The resulting zones included those with demonstrated interest and those with future potential but constrained by limited transmission headroom or permitting restrictions. The report recommends refinement of the zones through comprehensive headroom analysis.[24]

Generation zones are linked to the concept of simplified, pre-set prices for interconnection. As called for in Order No. 1920, the current interconnection queue will be an important input for identifying locations with developer interest. In addition to evaluating generator interconnections within the long-term planning process, Order No. 1920 further provides for network upgrades that were repeatedly identified in interconnection studies to be

20 Brattle Group reviewed PJM's interconnection study results for integrating 5.6 GW of offshore wind resources, identifying $1.3 billion in total identified transmission upgrade costs. Note that these interconnection study proxy costs were identified under PJM's pre-Order No. 2023 study approach. Pfeiffenberger, J., Hagerty, J. M., et al., *New Jersey State Agreement Approach for Offshore Wind Transmission: Evaluation Report*, Brattle Group, (October 26, 2022). Another analysis found a similar cost of $236 per kW based on integrating 15.5 GW of offshore wind with $6.4 billion in upgrades. Burke and Goggin. *Offshore Wind Transmission Whitepaper* (October 2020).

21 PJM forecast that proactive transmission planning could integrate 12.4 GW of offshore wind resources along with 14.5 GW of onshore wind, 45.6 GW of solar, and 7.2 GW of storage, for a total of just $2.2 billion. PJM, *Offshore Transmission Study Group Phase 1 Results* (August 10, 2021). A proactive planning effort in New Jersey for 6.4 GW of offshore wind resources resulted in selection of onshore transmission upgrades that reduced by approximately $1 billion, or two-thirds, relative to costs estimated in PJM's interconnection studies. Brattle Group, *New Jersey State Agreement Approach for Offshore Wind Transmission: Evaluation Report* (October 26, 2022), Figure 4.

22 SPP, *The Value of Transmission: 2021 Edition* (2021), p. 1.

23 Illinois Commerce Commission Staff, Brattle Group, Great Lakes Engineering, *Illinois Renewable Energy Access Plan*, prepared for Illinois Commerce Commission (December 2022), pp. 30-34.

24 *Id.*, pp. 36-39.

incorporated into Order No. 1000 plans.[25] However, as the location of proposed projects in the queue is heavily shaped by currently available transmission capacity, transmission providers should develop a mechanism to proactively identify locations where new resources would be developed "but for" current constraints on interconnection. Hence, generation zones are a necessity for the planning of additional transmission capacity.

### *Most-ready criteria*

Another necessity for the planning of additional transmission capacity funded by a simplified, pre-set price is a cap on entry. In each interconnection process cycle, the transmission provider should define a cap on the amount of planned available capacity in each zone that can be accessed through the entry fee.

If the volume of interconnection requests exceeds that amount of planned available capacity, we recommend that the transmission provider prioritize projects using "most-ready" criteria, as discussed in Reform 2-D. The transmission providers goal in establishing such criteria should be to ensure that the new generation projects allowed under the cap maximize the capacity that is expected to advance swiftly through the necessary study and construction phases.

## Providing interconnection cost certainty

The focus of the long-term proactive transmission planning process is on designing future transmission upgrades that reduce costs for both end-use consumers and interconnection customers. Implementing a simplified, pre-set pricing framework in a participant-funding model comes with the challenges of inaccurate upgrade cost forecasts and shortfalls in demand for interconnection capacity. If pre-set prices are to be offered, processes must be developed to address risks associated with this cost uncertainty and potential interconnection subscriber shortfall. This issue has been raised in both the JTIQ process and SPP's CPP Entry Fee proposal, with several options under consideration (including a potential "back-stop" charge to consumers) to address these risks.

We recommend transmission providers adopt a simplified, pre-set pricing framework and, in participant-funding systems, adopt a "back-stop" method to fairly allocate variances in cost or revenue. Without a fair "back-stop" method, if the participant is required to pay for all cost increases or cover any revenue shortfalls, the benefits underlying an initial pre-set price will be eroded, given that the quoted interconnection cost cannot be relied upon. Regions can retain participant-funding paradigms under this approach, with limited revisions.

## Trends in Cost Allocation Reform

Reforms proposed or implemented by SPP (Appendix 2.4), CAISO (Appendix 2.1), Bonneville Power Authority (Appendix 2.7.2), and the MISO/SPP JTIQ (Appendix 2.5) demonstrate a general industrywide trend towards simplifying cost assignment. Each of these regions is considering (or has implemented) reforms to better define and set in advance the costs charged

25 FERC Order No. 1920, paras. 1106-1107.

to interconnection customers. Rather than linking individual generators to project-associated network upgrades, these reforms move towards more uniform rates for interconnection that are based on the network upgrade costs required for the *portfolio of projects* needed to enable resource interconnection in that zone.

Recent academic research provides support for the portfolio approach over conventional project-by-project benefit assessments. Using a simplified model of the ERCOT system, Professors Shu and Mays found that even though five of six transmission upgrade projects "would not pass a benefit-cost test when assessed as individual projects, [they would be] part of a beneficial portfolio of projects."[26] Assuming this finding can be generalized, it suggests that individual projects that might be beneficial for an interconnection customer but not for the system might be grouped with projects that provide other benefits, with the resulting portfolio having benefits that are greater than the sum of its parts.[27]

### *Simplification of the system-funding model*

While five Regions have obtained variations from FERC's *pro forma interconnection tariff to use participant-funding models, all other transmission providers use a system-funding model.*[28] Compared to the participant-funding models, system-funding models feature less cost risk for interconnection customers. Under the system-funding model, costs, initially assigned to the interconnection customer, are ultimately refunded, with funding provided by consumers.

CAISO and Bonneville Power Administration have adopted zonal approaches that enable setting of interconnection costs on an advance basis. Their zonal approaches provide a pre-defined amount of interconnection capacity on simplified, pre-set price basis. The zonal approach stands in contrast to other transmission providers that use the system-funding model, where an interconnection customer's initial cost responsibility is calculated on a project-specific basis.

In its Order No. 2023 compliance filing, CAISO proposes even further reforms by proposing to change the timing for determining the maximum cost responsibility to the completion of its interconnection facilities study.[29] The maximum cost responsibility serves the purpose of capping ultimate cost responsibility for the interconnection customer and is calculated as the sum of the interconnection customer's full cost of assigned network upgrades and allocated costs for all other upgrades from its facilities study. These cost estimates are binding, and any costs above those estimates are the immediate responsibility of the transmission owner. Of course, given that most interconnection costs are refunded after generators are placed in service, most interconnection costs ultimately end up in transmission rates.

In addition, CAISO's recent Interconnection Process Enhancement approach aims to maintain cost certainty for developers who propose Energy Only (or ERIS) projects, as summarized in Appendix 2.1.3. Energy Only projects have a reimbursement option for network upgrades in zones where CAISO has identified the need for Energy Only resources in their IRP plans.

---

26 Han Shu and Jacob Mays, *Transmission Benefits and Cost Allocation under Ambiguity*, p. 22.

27 See: Public Power Underground, *Rich Glick on FERC Order No. 1920* (June 21, 2024), at 1:05.

28 System-funding Regions include CAISO, ERCOT (which is not under FERC's jurisdiction), and all transmission owners outside of the five Regions with participant-funding models.

29 CAISO, *Order No. 2023 Compliance Filing* (May 16,2024), Docket ER24-2042, Attachment A.

Projects in this path will be eligible for reimbursement of the cost of the necessary reliability network upgrades funded by the interconnection customer.[30]

Another system-funding model Region, ERCOT, has recently implemented a cap on an interconnection customer's cost responsibility (see Appendix 2.7.1). ERCOT (which is not subject to FERC jurisdiction on generator interconnection) has a very limited "connect and manage" study standard, which only identifies the local upgrades required to interconnect. The apparent benefit of ERCOT's reform is that it will discourage interconnection of projects with very high local network upgrade costs, without affecting ERCOT's approach to funding transmission system upgrades for projects with typical upgrade costs.

### *Simplification of the participant-funding model in SPP's CPP Entry Fee proposal*

Building on some of the lessons from the JTIQ process, SPP is developing the CPP Entry Fee proposal, described in Appendix 2.4, to set the cost responsibility of interconnection customers for required system upgrades up front, prior to queue entry. The CPP Entry Fee would cover all regional and subregional network upgrade costs; the interconnection customer would remain responsible for local network upgrade costs.

The largest distinction between the CPP Entry Fee proposal and other uniform rate cost assignment reforms is that the CPP Entry Fee would use a forward-looking assessment, considering network upgrade requirements beyond those of the interconnection customers participating in any one study.[31] This forward-looking assessment appears to be consistent with the long-term planning approach required by Order No. 1920.

The logic that a simplified, pre-set pricing approach is a consequence of "delinking" system network upgrades from interconnection study processes has been noted by others, including in the i2X Report.[32] The i2X report finds that because interconnection studies provide a link between a generator and the identification and cost responsibility for associated transmission network facilities, fully delinking network upgrades from interconnection processes would require further reforms to many of today's cost allocation approaches.

If adopted, SPP's CPP would reverse the traditional sequence of identifying projects' cost responsibilities after completing (and as a result of) individual interconnection studies. Instead, relying on a forward-looking assessment of network upgrade requirements for anticipated aggregate generator interconnection needs, SPP would develop a simple, pre-set Entry Fee up front for system network upgrade costs. Each project would then be studied to determine its cost responsibility for local network upgrade costs; upon study completion, those costs would also be pre-set. SPP's intention is, "to provide high levels of certainty of interconnection costs upfront, a known contribution level from the customers … when configuring solutions to needs across services and planning, as well as smoothing out service costs across multiple studies."[33]

30 CAISO, *2023 Interconnection Process Enhancements: Track 2 Final Proposal* (June 5, 2024), p. 18.
31 SPP Entry Fee Framework, p. 77.
32 i2X Report, Solution 3.3, p. 55.
33 SPP Entry Fee Framework, p. 70.

However, as discussed above, given the desire to create planned locations and pre-set pricing levels for interconnection customers, this level of certainty also creates risks. SPP's understanding of these risks is summarized in Figure 1.

**FIGURE 1** | **SPP-Identified Risks of CPP Entry Fee Proposal**[34]

- The potential for interconnection customers to select "poor interconnection locations ... that drive upgrade costs much higher than envisioned when setting the Entry Fee(s)."
- Distinguishing between upgrades required to allow interconnection at a POI and substation, line tap, or transmission upgrades that are required regardless of any specific interconnection request.
- Costs are difficult to predict due to the long construction timeline on the order of a decade. For network upgrades at the point of interconnection (POI), high quality cost estimates are provided by a transmission owner at the end of the study process in a facilities study. However, using facilities study costs would "make it difficult to consider these costs in the development of an Entry Fee."
- Costs may vary due to differing design standards of transmission owners, limitations of government entities, and changes to permitting standards.
- Other factors that affect upgrade cost accuracy include "inflation, interest rates, supply chain disruption, scarcity of materials, and skilled trades/human capital during the national buildout."
- The initial CPP Entry Fee rates may assume that future interconnection customers will both fund past upgrades (with remaining headroom) as well as future upgrades. There is a risk that the magnitude of future rate adjustments could be "so high that no [additional] customers [would] elect to interconnect in that zone," resulting in a failure to fully cover transmission portfolio costs.failure to fully cover transmission portfolio costs.

## Addressing challenges of pre-set pricing for participant-funded interconnection

SPP has begun evaluating how it will address the risks summarized in Figure 1.[35] However, MISO and SPP are grappling with how to address these risks in the JTIQ process. As of June 2024, there are two elements of the JTIQ process that are not ideally aligned to the simplified, pre-set interconnection cost framework that we recommend.[36]

First, MISO and SPP propose that JTIQ projects will be constructed and financed by transmission owners (known as "self-funding"), with interconnection customers paying the costs over a twenty-year period. However, interconnection customers will also be required to provide financial security (e.g., a letter of credit or surety bond) for the outstanding unpaid costs to the transmission owners.[37] This financing method may not be cost-effective and may be discriminatory to interconnection customers.[38]

In 2015, FERC determined that transmission owners may not unilaterally elect self-funding. Summarizing its 2015 decision, FERC explained that such "unilateral election may increase costs to interconnection customers without an increase in service ..." because interconnection customers may have "other options to finance the cost of the network upgrades [on] more

34 SPP Entry Fee Framework, pp. 65-67, 71-73.

35 SPP Entry Fee Framework.

36 Some stakeholders also disagree with the overall cost allocation between interconnection customers and "load" (the consumers of power delivered by the transmission owners). This issue is intertwined with decisions related to the allocation of benefits from federal funding and is beyond the scope of this report.

37 MISO, *Redline Changes to MISO SPP JOA Section 9.4* (March 6, 2024), p. 11. MISO, *Supplemental Draft JTIQ Commitment Agreement* (July 17, 2024), p. 5.

38 FERC, *Order to Show Cause* (June 13, 2024), EL24-80, para. 52.

favorable terms and rates."[39] However, FERC's 2015 decision remains under active litigation.

Self-funding could undermine an entry fee framework if it results in unnecessary costs to consumers. This outcome is suggested by MISO and SPP's proposal to finance JTIQ projects by both allowing transmission owners to earn a full return on investment and also requiring interconnection customers to provide a full financial guarantee of project revenues, which may cause consumers to pay unreasonably high costs.

Second, the proposed pre-set JTIQ generator charge (annual charge to interconnection customers) does not provide cost certainty. MISO and SPP propose to true up costs after the projects are in-service and final project costs are known.[40] This proposal undermines the entry fee framework because interconnection customers are expected to enter into binding commitments, but the transmission owners are not similarly obligated to control costs or avoid late discovery of project requirements that increase costs.

**... consistent with our proposed entry fee framework, MISO and SPP propose that transmission owners should be the "back-stop if there are insufficient generator interconnection commitments to reach full subscription for the JTIQ Portfolio."**

On the other hand, consistent with our proposed entry fee framework, MISO and SPP propose that transmission owners should be the "back-stop if there are insufficient generator interconnection commitments to reach full subscription for the JTIQ Portfolio."[41] This is appropriate because interconnection customers have no responsibility for forecasting subscriptions or creating conditions attractive to subscribers.

### *True-up to actual costs and back-stop to undersubscription*

Considering the challenges demonstrated in the JTIQ process, we recommend a different approach to addressing the risks summarized in Figure 1, beginning with addressing the second issue discussed above, the generator charge true-up and the back-stop. A participant-funding model with pre-set prices should include discrete "back-stops" to address the various cost risks associated with uncertain construction timelines, costs, and subscription rates for planned transmission upgrades. Notably, we have developed a structure that shares this cost risk between interconnection customers, the transmission owner and transmission customers in the Region.

39 As summarized in: FERC, *Order to Show Cause* (June 13, 2024), EL24-80, para. 16.

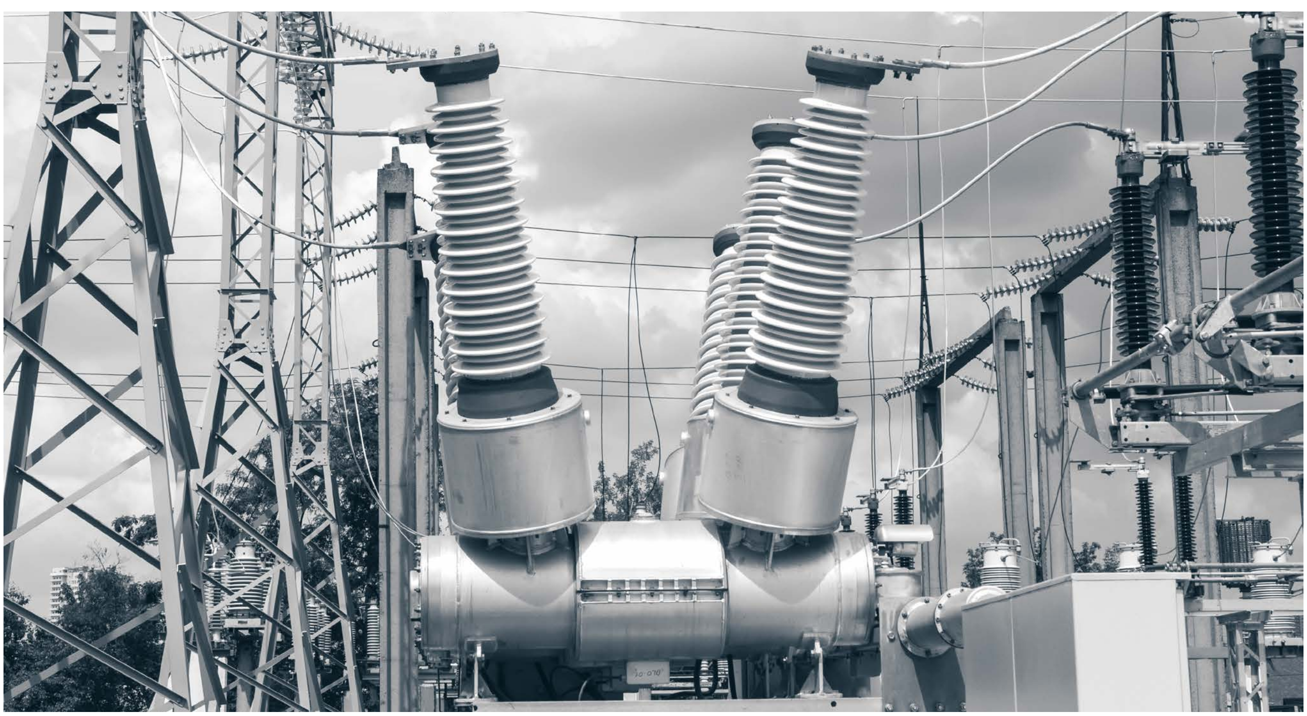
40 MISO, *JTIQ Presentation* (June 18, 2024), p. 26; MISO, *JTIQ Attachment JJJ Draft* (June 18, 2024), p. 17. See stakeholder feedback available at the same URL.

41 MISO, *JTIQ Presentation* (June 18, 2024), p. 23.

Our proposal for sharing the "back-stop" would result in interconnection customers paying a three-part interconnection charge, including:

- A pre-set interconnection charge published by the Region in advance of the cluster study request deadline that is based on a forward-looking assessment of **system network upgrade** costs associated with the Region's forecast of resource development, based on proactive regional planning.[42]
- A **local network upgrade** cost associated with the project's share of costs identified in facility studies to upgrade the point of interconnection (POI) on a direct assignment basis. Interconnection customers should benefit from any savings due to scope changes after the facility study is complete, providing an incentive for those customers to suggest cost-saving alternatives to the facility study findings.
- A formula-based **network upgrade cost true-up** indexed to macro-economic variables such as inflation and interest rates, which would revise the assigned local and system network upgrade costs as the applicable indices change.

Interconnection customers will continue to have responsibility for costs, as identified by the Region and the transmission owner, at the time of the interconnection agreement, *plus* adjustments for cost changes (in either direction) where inflation, interest rates or any other formula-based macroeconomic cost-driver deviates from the assumptions in the facility study. Where the current JTIQ proposal assigns these cost risks entirely to interconnection customers, we recommend a formula-based adjustment that provides interconnection customers with a degree of cost certainty and fixed *elements* in the cost formula.



42 Regions may adopt zonal pricing if appropriate.

The remaining cost risk would be shared by the Region and the transmission owner (recovered through rates, if prudently incurred), as summarized in Table 2.

**TABLE 2** | **Sharing of Cost Risks Between Interconnection Customers, Transmission Owners, and Regions in an Entry Fee Framework**

| Cost Risk | Entity Assigned Cost Risk | Cost Assignment Solution | Rationale |
|---|---|---|---|
| **Cost increases for local and system network upgrades: Inflation and interest rates** | Interconnection customer | Formula adjustment to initial pre-set cost assignment based on CPI inflation and FERC interest rates, or other indices[43] | Interconnection customers' business models already consider these risks for the costs of generation facilities, and are thus well-adapted to include risks associated with macroeconomic factors in their business plan. |
| **Cost changes for local network upgrades: Construction scope** | Transmission owner | One-way adjustment to direct assignment costs | Transmission owners are responsible for the accuracy of the facility study, which determines the construction scope for local network upgrades under SPP's CPP Entry Fee proposal. Interconnection customers should not be responsible for cost increases due to scope changes identified after the interconnection customer has accepted cost responsibility. Furthermore, interconnection customers should be encouraged to propose cost-saving alternatives to the transmission owner. If such alternatives are accepted, the resulting cost savings should be passed through to the interconnection customer. |
| **Cost changes for local and system network upgrades: Construction scope,[44] design standards, supply chain, materials, and workforce** | Transmission owner | Net cost changes (after the formula-based true-up) are the responsibility of the transmission owner | Cost changes closely related to facility construction are best managed by the transmission owner. This does not imply that the transmission owner "controls" all factors that may drive cost changes, but the transmission owner is in the best position to manage these costs.[45] |
| **Revenue shortfalls due to insufficient subscription to transmission upgrades** | Region | Revenue shortfalls (or surpluses) collected (or refunded) across the entire planning region | The Region is responsible for the resource forecast and planning of backbone system upgrades. Accordingly, the Region should accept cost responsibility for revenue shortfalls (or surpluses). In the case of multi-regional planning, more than one Region could share cost responsibility. |

43 Regions and transmission owners can set revenue requirements that consider varying macroeconomic conditions, as allowed by FERC, including potentially utilizing industry-specific inflation indices.

44 Construction upgrades for local network upgrades are handled slightly differently, as noted above.

45 CAISO provides an example of a Region that has already adopted this approach. Transmission owners are required to publish facility upgrade costs. Those costs are used to determine the maximum cost responsibility for interconnection customers.

Because SPP's CPP Entry Fee proposal is intended to provide cost certainty to interconnection customers, any variation from the forecast cost must be included in the revenue requirements of the Region and the transmission owners. SPP's intention is that over time, those variations would balance out.[46] As a result, the proposal is intended to result in no net change to SPP's existing cost assignment policies, but there could (and likely would) be deviations for each project and each interconnection customer.

Nonetheless, the Region and the transmission owner would need to recover any cost overruns or revenue shortfalls, if they were prudently incurred. For example, transmission owners have the opportunity to reduce cost risk through best management practices, advanced materials procurement practices, outsourcing using fixed price contracts, or financial hedging. For investor-owned transmission companies, their opportunity to recover cost overruns would be subject to prudency review.

### *Funding responsibility in a simplified, fixed interconnection model*

As summarized above, a significant point of controversy is whether transmission owners may simultaneously elect self-funding and require substantial financial commitments.[47] To minimize costs, it is important that the funding mechanism should not both include a rate of return for transmission owners that compensates them for assuming full cost risk and require interconnection customers to provide financial security that substantially reduces that same cost risk. Such an outcome would result in unjustified costs that would be passed through to consumers.

To eliminate double-payment for assuming financial risks, we suggest that FERC consider allowing transmission owners to determine how to allocate the financial risks such that there is no duplication of risk-related cost. The transmission owners would set the percentage of costs that interconnection customers would be required to commit to and make on an up-front basis. This percentage would be applied to each of the three parts of the interconnection charge described above (system upgrades, local upgrades, and cost true-up). The remainder of the cost would be self-funded by the transmission owner with those costs recovered from the generator. For that remainder, interconnection customers would not be required to commit further credit or capital on an up-front basis.

This approach offers four advantages:

- If the transmission owner faces capital constraints, it can elect to require a higher up-front cost contribution from interconnection customers in order to avoid finance-related delays. As discussed in Appendix 3.1.3, PG&E and SCE have delayed transmission upgrade projects due to their corporate capital constraints.
- The transmission owner can set the up-front cost contribution from interconnection customers high enough to eliminate over-subscription (i.e., interconnection requests for

46 "By design, this model will develop rates for customers assuming future customers will both fund future needed transmission upgrades and possibly "balance the books" for past upgrades. The cost contribution from service customers could occur over multiple cycles until overall cost responsibility is met." SPP Entry Fee Framework, p. 71.

47 This recommendation considers projects where the transmission owner is constructing the transmission upgrades. If the transmission owner is not responsible for constructing (and potentially operating) the transmission upgrades, then the tradeoff between financing between interconnection customers and the entity constructing the transmission upgrades should be evaluated based on case-specific circumstances.

more capacity than included in the headroom created by the transmission plan).

- Consumers are protected from ultimately incurring duplicative risk-related costs from both transmission owners and interconnection customers.
- Setting more reasonable credit requirements will promote competition among developers of new generation resources rather than promoting business consolidation to manage high financial obligations on balance sheets.

**REFORM 2**

# UTILIZATION

*Implement a fast-track process to utilize existing and already-planned interconnection capacity.*

Transmission providers should adopt interconnection processes that efficiently interconnect new resources at locations on the system with existing and proactively planned grid capacity ("headroom"). Significant near-term opportunities exist to increase the rate of interconnection and can be unlocked by processing those interconnection requests to access headroom on a "fast-track."

While the grid has significant available capacity ("headroom") in many areas, interconnection customers find that headroom difficult to locate with certainty and, when located, experience unnecessarily inefficient processes to ultimately connect with the system. The limited information available and lack of clear processes to utilize available capacity creates cost and schedule uncertainty for interconnection customers and contributes to the tendency for interconnection customers to submit several requests at various locations on the system before selecting the projects they will build based on the results of the interconnection study process. As currently designed, the complex and time-intensive interconnection process is used by interconnection customers for screening potential resource additions, many of which may not get developed due to other challenges that new resources face in the development process.

From the perspective of the transmission providers, the record levels of interconnection requests over the last several years have become increasingly unrealistic (in terms of what would ultimately be developed) and unmanageable (in terms of studying the large volume of requests). The large number of requests slows down the entire interconnection process and creates cost and schedule uncertainty for interconnection customers.

Shifting to a process with a more manageable number of requests is best accomplished through two complementary reforms. By providing certainty regarding future transmission upgrades and costs (the "entry fee"), Reform 1 addresses interconnection requests that require substantial upgrades to interconnect. Reform 2 recommends an approach for expediting interconnection requests that do not require substantial network upgrades through a "fast-track" process.

Seeking to assist interconnection customers with locating available headroom, FERC Order No. 2023 required transmission providers to publish available transmission capacity as "heatmaps." Yet interconnection customers still expect to face ongoing challenges in identifying locations (points of interconnection, or POIs) with headroom prior to submitting a request. This is due to:

1. Lack of up-to-date and actionable information about available or planned capacity on the system;
2. The large amount of resources ahead of them in the queue which might consume available capacity; and
3. The inability to replicate a transmission provider's interconnection study methodologies to identify available capacity.

Furthermore, interconnection customers often find it difficult to obtain basic technical information about potential POIs, such as the status of terminal bays (number open), presence of fiber options, flowgate data and any known limiting element(s) at a potential point of interconnection.

Some existing interconnection study processes are intended to expedite connections to POIs with headroom. But most such requests for expedited study (including those seeking to use headroom created by generation anticipated to retire) must wait alongside requests that trigger upgrades for the full set of requests to be studied – and then re-studied (and re-studied again) as projects at high-cost POIs drop out of the process.

Accordingly, we recommend adding or enhancing the fast-track process by separating projects that do not require study from those that do by improving information about headroom and POIs; creating or updating fast-track processes for available capacity, including generator retirements; and enabling competition for such opportunities by using "most-ready" criteria. Informed by the goals of Orders No. 1920 and No. 2023, these reforms could be adopted by transmission providers as part of compliance processes, but are beyond the strictly enumerated requirements mandated by FERC. Should transmission providers elect not to pursue these improvements, FERC could require such provisions in a future reform effort.

### REFORM 2A. Provide transparent, timely, and actionable information for interconnection customers to identify available or low-cost headroom.

The requirement in Order No. 2023 to include heatmaps of available transmission capacity should be a useful tool to guide interconnection. Based on recent interviews, however, interconnection customers have shown limited interest to-date in heatmaps due to the expectation that they will provide little to no value to their development process since they are not actionable.[48]

Heatmaps based on currently available information are not actionable due to (1) the limited information included in the heatmaps, (2) the lack of available capacity on the system (and often reflected in heatmaps) due to limited proactive planning and a reluctance to rely on

48 Interconnection Scorecard, p. 39.

lower-cost solutions (such as GETs or simple RAS), and (3) the current backlog in an unrealistically large interconnection queue, such that the system capacity shown on heatmaps is likely to be very different in the future when their requests are eventually studied and interconnection agreements can be signed. Transmission providers need to continue ongoing efforts towards reducing the current backlogs in the interconnection queues so that interconnection customers can expect that their interconnection request will be studied based on conditions sufficiently similar to those shown in the heatmaps.

**To create useful heat maps, transmission providers should provide transparent, timely, and actionable information on available and planned system capacity so that developers can identify available or low-cost system capacity prior to submitting their interconnection requests.**

In addition to information about system capacity, basic technical information about the potential POIs should also be publicly available to support interconnection customers in identifying desirable POIs and focus interconnection requests on the most likely sites to develop.[49] FERC did not evaluate this question in Order No. 2023. Transmission providers should provide information on the status of terminal bays (number open), presence of fiber options, flowgate data and any known limiting element(s) at a potential POI if feasible to provide.[50] In future reform efforts, FERC should evaluate which transmission providers' POI information proves most valuable to stakeholders and interconnection customers and expand availability of particularly valuable information.

To create useful heat maps, transmission providers should provide transparent, timely, and actionable information on available and planned system capacity so that developers can identify available or low-cost system capacity prior to submitting their interconnection requests. This information will also provide clear direction for accessing the fast-track process proposed in Reform 2-B.[51]

- **Transparent**
  Transmission providers should provide interconnection customers as much information as possible on the amount of available system capacity at a nodal or zonal level based on the latest interconnection and transmission planning studies. Transmission providers should identify all incremental network upgrades, additional capacity available in excess of the studied injections (e.g., due to the lumpy nature of transmission additions), and how much of the headroom will potentially be used by interconnection customers that are already proceeding through the interconnection process. The transmission providers should also provide available information on locations that offer low-cost interconnection opportunities based on results from recent interconnection studies. Final power flow models for all recent studies should be publicly available to allow interconnection customers the ability to identify

---

49 Interconnection Scorecard, p. 40.
50 Flowgate data for each POI should include disconnect switches, breakers, transformers, conductors, series reactors, and ground clearances of lines.
51 i2X Report, Solutions 1.1 and 1.2, pp. 14-19.

the limiting elements on rated paths and additional POIs with available or planned headroom. Several good examples of the information currently provided by transmission providers to interconnection customers based on the most recent interconnection and planning studies are listed below.

- **Timely**
  Transmission providers should regularly update heatmaps based on the latest transmission planning and interconnection studies in advance of interconnection request deadlines so that interconnection customers are able to identify attractive locations for their resources in the next interconnection request window.
- **Actionable**
  In order for the transparent and timely information to be useful, it also must be actionable. However, the large size of the current interconnection queues and associated study backlogs prevent interconnection customers from acting on the limited information available to efficiently complete the interconnection process. Transmission providers must continue to reduce the current queue backlogs so that interconnection customers can expect that their requests will be studied based on system conditions sufficiently similar to those shown in the heatmaps. Importantly, transmission providers should create fast-track processes that allows interconnection customers with "most-ready" projects to quickly act on the available information, as discussed in Reform 2-B, Reform 2-C, and Reform 2-D.

Several transmission providers already provide information helpful for identifying grid locations with available or low-cost system capacity for interconnection, assisted by an associated proactive planning process considering generator interconnection needs. In each of these cases, transmission providers have relied on proactive transmission planning to create available interconnection capacity. As soon as system enhancements are approved through the planning process, they are included in the base case models used in interconnection studies, or integrated within processes that provide otherwise fixed- or low-cost system access. By accounting for regional upgrades as soon as they are approved, interconnection customers will have better information to develop their new resources at locations with available capacity. Subsequent interconnection studies will also prove more efficient as reliability violations on larger, regional transmission facilities will already be resolved by the upgrades approved through the planning process.

### *CAISO provides helpful information from recent interconnection studies.*

For the recently completed Cluster 13 Phase II interconnection study, CAISO posted a summary of the results with a detailed list of POIs that either (1) do not require any additional network upgrades, (2) are enabled by Remedial Action Schemes (RAS), or (3) will offer headroom created by transmission already under development.[52] While helpful information, the Cluster 13 results were posted in December 2023, over two years following the end of the submission window for Cluster 14. More timely posting of interconnection study results will enable improved POI selection.

52 CAISO, *Briefing: Resources Available Near-Term Interconnection* (December 5, 2023).

CAISO similarly posted a summary of interconnection headroom in specific zones created by upgrades approved through the 2023-2024 Transmission Planning process.[53] The summary includes the affected resource locations, the conditions under which constraints bind, the current and future capacity deliverability values, and the costs of the associated network upgrades. CAISO does not provide additional information on the costs of interconnection by location beyond these POIs with limited to no upgrades noted above.

***MISO's Long-Range Transmission Planning (LRTP) process will identify locations with future support for resource development.***

MISO is proactively building out its transmission system through its LRTP process based on the projected resource mix and location of new resources as informed by MISO scenario-based planning studies, as summarized in Appendix 2.3. MISO does not provide information on locations with available capacity but provides information on its future scenario generation portal ("JuiceBox") about where new resources are assumed to be located in its transmission planning studies.[54] This allows interconnection customers to see where new resources will likely find capacity created by the upgrades developed via the LRTP process.

***Denmark and France: Online portals with interconnection capacity and charges.***

Online portals with location-specific information on available interconnection capacity and interconnection charges have been created by the system operators in Denmark and France (for distribution-level interconnections). Generation developers that meet all development milestones (including permits) are able to use the online portal to sign up for the available capacity on a first-come, first-serve basis.[55]

## REFORM 2B. Create a fast-track process for locations with clearly defined existing or planned available capacity.

To efficiently leverage proactive upgrades and information on existing or planned system headroom, transmission providers should create fast-track processes to advance "most-ready" projects utilizing available capacity through the interconnection study process on an expedited basis. The benefits of such a fast-track process include: guiding interconnection requests towards suitable system locations, streamlining access for requests with no adverse impacts on the system, improving study efficiency for remaining requests, and enabling more efficient coordination between long-term planning and the remaining generator interconnection processes.[56] This fast-track process will also reduce the volume of interconnection requests at other system locations where additional network upgrades will have to be analyzed and designed.

53 CAISO, *Interconnection Area Constraint Mapping* (April 4, 2024).

54 MISO, Juicebox.

55 Rte online portal. The Danish Energinet notes that at locations with available capacity, interconnections can typically be achieved within 1-3 years. If reinforcements need to be planned, the planning and construction process may take 3-6 years. See their online portal available here (right click for translation to English).

56 i2X Report, Solution 2.5, p. 28.

FERC has established some "fast-track" processes via provisions in Orders No. 2006 and No. 792 and there are several further precedents for "fast-track" processes (see Section 2-B.2).[57] However, we propose a different purpose and structure for a fast-track process that is closely linked to accessing existing and planned interconnection capability. In Orders No. 2006 and No. 792, FERC limited fast-track options to "certified" small-generating facilities no larger than 2 MW, as well as inverter-based resources for facilities no larger than 5 MW.[58] We discuss several other precedents for "fast-track" processes in Section 2-B.2. FERC should increase the scope of fast-track processes so that they apply to resources of all sizes and are based on requests to utilize already available or planned system capability, potentially including new capability created by regional transmission system plans where an "entry fee" method is not adopted.

The scope of fast-track processes should be strictly limited to requests to utilize existing (including planned available) headroom, quantified as recommended in Reform 2-A. To the extent that the transmission provider's pre-request headroom does not specify an amount of available capacity at specific points of interconnection, then the eligibility of a request for fast-track processing should be verified through a "no harm" test. For example, transmission providers often apply material modification standards to determine that a change in an existing request would not have a meaningful impact. Similar standards could be developed for verifying that a project proposing to utilize existing available capacity is eligible for fast-track processing. Eligibility of requests for headroom available as surplus (unused capacity for an existing interconnection) or planned available capacity should be relatively straightforward using existing models.

In Order No. 2023, FERC declined to expand alternative methods of interconnection study beyond the cluster study because leaving "a significant amount of discretion to the transmission provider to create new study processes for processing any types of interconnection requests it chooses outside the cluster study process" would be too open-ended and potentially result in a discriminatory interconnection process.[59] We anticipate that a focused fast-track process would avoid these concerns while enabling efficient access to capability created through long-term planning. It would enable quicker access for interconnection requests at POIs with available capacity while also reducing the volume of interconnection requests that must be modeled in the cluster study process. Focusing the cluster study process on resources and locations that are likely to require network upgrades should reduce the time and resources needed by transmission providers to complete cluster studies (and restudies).

### *2B.1. Recommended Fast-Track Process*

We recommend that, through their future reform efforts, transmission providers develop fast-track processes that include the following steps:

---

57 FERC, *Order No. 2006: Standardization of Small Generator Interconnection Agreements and Procedures* (May 12, 2005); FERC, *Order No. 792: Small Generator Interconnection Agreements and Procedures* (November 22, 2013).

58 The maximum size for Fast Track qualifying inverter-based resources was amended in FERC Order No. 792 (para 106), citing FERC Order No. 2006. See FERC Order No. 792, Pro-Forma SGIP, Attachment 3 and Attachment 4 for certification standards. Certified fast track facilities are required to conform to a range of technical standards including IEEE 1547.1. FERC Order No. 792, SGIP Attachment A (pdf page 206).

59 FERC, *Order No. 2023: Improvements to Generator Interconnection Procedures and Agreements* (May 13, 2024). Note that FERC did clarify that (a) interconnection customers can access unused interconnection service as soon as facilities are in the process of being placed in service and (b) that storage resources may use surplus interconnection service. FERC Order No. 2023, paras. 1436-1437, 1439, 1444.

- Transmission providers post information on existing and planned available system capacity, including capacity created through proactive planning processes to identify cost-effective upgrades based on future generator interconnection needs (Reform 2-A);
- Transmission providers set criteria for requests allowed to participate in the fast-track process that should include:
  - Requests at locations with clearly defined headroom, as identified by transmission service providers based on recent transmission planning and interconnection studies,
  - Interconnection capability sharing and generator replacement requests at existing generator locations, and
  - Requests at POIs with available system capacity identified by interconnection customers, including headroom created by retiring resources.[60]
- Interconnection customers indicate in each interconnection request whether the project meets the entry criteria for the fast-track process;
- Transmission providers identify the "most ready" projects to include in the fast-track process up to the amount of identified available capacity (Reform 2-D);
- Transmission providers screen eligible fast-track requests to confirm the resource can take advantage of the available headroom without creating material adverse impacts (utilizing transparent screening study criteria that interconnection customers can replicate in advance of requests);
- Requests that are not prioritized or fail the screening analysis enter the cluster study process; and
- For requests that pass the screening analysis, transmission providers will conduct a facility study to determine costs for attachment facilities,[61] proceeding quickly to a draft interconnection agreement.

As noted in the i2X Report, fast-track processes can quickly and efficiently leverage existing and already-planned system capacity, creating opportunities for resource developers to identify locations that require minimal upgrades in the interconnection process and fast-track the development of these resources (which may also be necessary to maintain regional resource adequacy).[62] However, a fast-track process is dependent on transmission providers to clearly identify locations with headroom in advance of interconnection requests, as recommended in Reform 2-A.[63]

An example of the needs for such a fast-track process can be found in PJM's State Agreement Approach (SAA) in New Jersey. New Jersey planned onshore transmission and created system headroom for 6.4 GW of incremental offshore wind generation resources at well-defined

60 Transmission providers could allow interconnection customer to provide their own studies, assuming sufficiently transparent and repeatable frameworks for the necessary analyses. This approach would limit the transmission service provider's role for approving fast-track requests to verifying the results of independently-conducted studies by qualified entities.

61 The transmission owner could define attachment facilities to include limited types of local network upgrades such as replacing aging equipment. Concurrent with the facility study, potentially affected systems should be notified of the potential interconnection agreement, consistent with Order No. 2023 requirements.

62 i2X Report, Solution 2.5, p. 28

63 FERC Order No. 2023, para 392, citing comments by Enel, PJM, Bonneville Power Authority, and National Rural Electric Cooperatives Association.

POIs via the SAA process. FERC approved an order specifying that the system headroom was created for the purpose of interconnecting new generation, in particular New Jersey offshore wind.[64]

Yet, even after the system headroom is assigned by the New Jersey Board of Public Utilities, those interconnection customers are nonetheless required to enter (or re-enter) the interconnection process at the end of the existing PJM queue. Requiring those resources to go through the full interconnection process along with all other resources adds significant delays (and associated risks and costs) to utilizing the planned POIs for their specified purpose.[65] A full re-study of SAA resources assigned capacity and for which network upgrades have already been designed and constructed is unnecessary.[66]

The system headroom created by the SAA upgrades ("SAA Capability") was developed for the specified offshore wind resources in a manner similar to how long-term transmission plans will include forecasted new generation. By analogy, the same critique applies to processes that require other generation resources attempting to utilize existing or already-planned headroom. Because no new transmission needs have to be evaluated and no additional network upgrades need to be designed for these locations, the Regions should instead offer a fast-track process for "more-ready" resources (or, in the example of the New Jersey SAA, to resources with planned headroom assigned by the Board) to access the planned headroom.

Similarly, our recommended fast-track process includes the ability for retiring resources to transfer their headroom to a new resource (as described further in Reform 2-D, below). Similar to our recommended process for expediting transmission headroom through a proactive planning process, the transfer of existing system headroom to new interconnection customers should be studied in an expedited manner to ensure that the new resource at the existing POI does not exceed the existing headroom made available by the retiring resource.

A fast-track process can be consistent with either participant-funding or system-funding models, as seen across current regional variations. For example, CAISO employs a crediting mechanism, whereby load ultimately pays for all network upgrades; PJM allocates SAA-related upgrade costs directly to the state; and SPP's proposed Consolidated Planning Process (CPP) would charge an "entry fee" for the cost of upgrades planned in advance of resource interconnection requests. For each case, pre-planning the system capabilities necessary to enable new resource interconnections allows for the development of fast-track interconnection processes without requiring fundamental change to the cost allocation model.

---

64 FERC, *Order Accepting Agreement re PJM* (April 14, 2022), Docket ER22-902. See Schedule 49 and order.

65 PJM, *SAA Agreement, Rate Schedule No. 49* (January 27, 2022), Docket ER22-902.

66 Note that, as of the time of the New Jersey SAA award, all identified reliability violations associated with the injections were satisfied to the satisfaction of PJM. Any reliability violations created in the interim and identified at the time of the interconnection of the New Jersey offshore wind resources would necessarily have been caused by system evolution since the time of the award of the SAA facilities.

### *2B.2. Precedents for Fast-Track Processes*

FERC has previously approved similar approaches (outside of Order No. 2006 fast-track processes) for transmission providers to accelerate processes for interconnection customers that require minimal network upgrades towards final interconnection agreement.

#### *PJM expedited transition process for interconnection requests with low-cost network upgrades*

PJM's transitional process in its recently approved generator interconnection reform proposal enables resources that require less than $5 million in network upgrades to move ahead into an "expedited process" to be studied in advance of the remaining process. PJM's process demonstrates the feasibility of advancing low-impact interconnection requests with limited delay, even if requiring some non-zero amount of local network upgrades. While limited in scope to PJM's transition window, PJM's justification that expediting studies for projects with less than $5 million in network upgrade costs may also be applicable to a broader set of requests that utilize available headroom. As PJM noted concerning its transitional process, the studies necessary for interconnection customers under this $5 million threshold for network upgrades are "fairly straightforward."[67]

#### *MISO, SPP, and PacifiCorp re-use of existing capacity*

A fast-track framework similar to our recommendation is already available in MISO, SPP, and Pacificorp for resources able to share or re-use existing POI capacity at aging or retiring plants. As long as the capacity of the interconnection request does not exceed the existing plant's interconnection capacity, the system operators assume, and confirm through a screening analysis, that the request would not adversely impact the existing grid. If the screening analysis identifies material adverse impacts, the resources enter the full interconnection study process to identify transmission needs and plan the necessary upgrades.[68] In Reform 2-C, we recommend that similar processes be created or updated by all transmission providers.

#### *Rte first-come, first-serve process for ready-to-build projects*

Rte in France posts the amount of available capacity at each node on its system, along with a uniform interconnection charge with each zone. Much of the available capacity is the result of a proactive planning process to prebuild interconnection capacity on its lower-voltage grid (where the majority of renewable resources are developed and interconnected) at locations with attractive renewable development potential. Fully permitted resources that are "ready" to utilize the capacity are then able to request the available interconnection capacity on a first-come, first-serve basis. If the volume of interconnection requests exceeds the available capacity, the surplus of requests is considered in the next planning cycle.

#### *Similarities with point-to-point transmission service*

Fast-track options for resources at POIs with headroom also mirror the familiar structure for offering and reserving point-to-point transmission service. Here, the transmission provider

67 FERC, *Order Accepting Tariff Revisions Subject to Condition re PJM* (November 11, 2022), Docket ER22-2110, para 40.
68 Ben Greene, *MISO/SPP Generator Replacement Process* (July 31, 2023), American Electric Power for PJM.

posts available transmission capacity (ATC) on OASIS. Customers can sign up for the available capacity (and quickly reserve it on OASIS) on a first-come, first-serve basis as long as they are willing to pay the full rate for the associated service. Only if a transmission service request exceeds the available capacity, will the customer have to wait so the transmission service request be studied to identify necessary transmission upgrades before the service can be provided.

### **REFORM 2C.** Create or update fast-track processes for the efficient replacement of existing plants.

Even before long-term planning can develop regional facilities to enable additional system headroom, the most attractive points of interconnection with immediately available capability in many cases are locations where aging existing generating resources are interconnected. NERC anticipates over 100 GW of fossil-fired and nuclear generator retirements over the next decade opening up opportunities for low-cost interconnection at those sites.[69] These aging existing plants often are dispatched only as peaking resources and expected to retire in the relatively near future (even if retirement dates have not yet been announced). Looking into the future, such existing fossil resources will increasingly have headroom available during more hours of the year due to increasingly stringent emissions limitations, and as run-time restrictions continue to be expanded nationwide.

Headroom at existing POIs can be made available for sharing with new resources if the existing generating resource (such as aging peaking plants) rarely utilizes the full system capability associated with its interconnection service agreement. FERC has previously sought to develop "surplus interconnection service" that achieves many of these goals. In Order No. 845, FERC found that surplus service would "reduce costs for interconnection customers by increasing the utilization of existing interconnection facilities … rather than requiring new ones," and "improve wholesale market competition by enabling more entities to compete through the more efficient use of surplus existing interconnection capacity."[70]

The implementation of FERC-mandated surplus interconnection service has varied widely across regions and the Commission's recent revisions in Order No. 2023 did not materially change the scope of surplus service. While some transmission providers have successfully implemented this option, others have articulated challenges with fully utilizing the service. Notably, given the wide variations in assumptions underlying interconnection studies (as discussed in Reform 3-C), transmission providers are likely to have different views on which transmission capability is actually "surplus" to the existing interconnection and therefore eligible to be shared. As a result, some regional transmission providers have implemented study methods that significantly limit the viability and availability of the service relative to other regions. Even so, FERC did not consider reforms related to the efficient reuse of interconnection headroom where existing generators are retiring or being replaced in Order No. 2023.[71]

---

69 North American Electric Reliability Corporation, *Statement at FERC 2023 Reliability Technical Conference* (November 9, 2023), Docket AD23-9.

70 FERC, *Order No. 845: Reform of Generator Interconnection Procedures and Agreement* (April 19, 2018).

71 FERC Order No. 2023, paras. 1736, 1743.

We recommend that transmission providers develop an enhanced approach to sharing interconnection service that builds on existing "surplus" services which, in combination with interconnection transfer options, will also enable new resources to continue operating after the retirement date of the host resource. These revisions would build on the fast-track process recommended in Reform 2-B for accessing available headroom.

An expanded surplus service process would expedite interconnection requests at those sites while providing the owner of the existing resource an opportunity to be compensated for the transmission capability it funded for the existing resource. Where feasible, existing dispatchable resources could remain in service to enhance reliability. Any such option would require an agreement (such as MISO's "energy displacement agreement") that ensures that the combined energy and capacity output of the resources sharing an existing POI does not exceed the energy and capacity of the interconnection rights at the POI. We recommend that, if transmission providers are not willing to offer such enhanced surplus service options, FERC require them to do so as part of future reform efforts.

We recommend that, to create or update existing surplus interconnection service to fast-track access to headroom being created by retirements, transmission providers should:

- Allow resources utilizing sharing service to continue to operate in perpetuity under a new interconnection agreement, which would require the transfer of interconnection rights from the retiring existing resource, as studied and confirmed through generator deactivation processes (requiring the development of a new interconnection agreement for the resource previously sharing headroom);
- Enable verifiable operating agreements at existing generators' POI to provide additional options for co-location and sharing of the POI that would not exhibit material impacts beyond the existing injections and capability; and
- Clarify ERIS study provisions (discussed further in Reform 3-A), further reducing identified material impacts of ERIS facilities seeking to use shared interconnection capability of NRIS generators, particularly when dispatch is controlled using verifiable control technology.

### *2C.1. Industry trends supporting re-use of existing plants' interconnection locations*

System capability at existing POIs can be made available for sharing with new resources if the existing generating resource does not regularly utilize the full system capability associated with their interconnection service agreement. A steadily increasing number of deployed solar resources are adding storage to the system and sharing POI capability.

Looking into the future, existing fossil resources will increasingly have headroom available during more hours of the year due to increasingly stringent emissions limitations and as run-time restrictions continue to be expanded nationwide. The EPA recently finalized a rule for reducing carbon dioxide emissions at existing coal and gas plants, subjecting resources either to emissions-based runtime limitations or mandated retirement.[72]

72 U.S. Environmental Protection Agency, *New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule* (May 9, 2024).

### *2C.2. Variations in Surplus Interconnection Service*

MISO provides processes for use of surplus interconnection service with a much higher degree of flexibility than most other regions.[73] MISO requires facilities seeking surplus interconnection service to have no material impact on the transmission system, starting with the presumption that no material impacts exist as long as total energy and capacity limits of the existing POI are not exceeded. MISO then conducts screening analyses to ensure there are no material system impacts (rather than presume such impacts).

MISO has recently adopted revisions allowing more flexibility in the timing of surplus requests, which was noted by FERC in its generator interconnection NOPR.[74] As a result, MISO has received 3.6 GW of active surplus service requests since early 2021.[75] These surplus service requests are primarily, but not exclusively, for the addition of battery storage at solar and wind sites with interconnection. "Energy displacement agreements" between existing generators and proposed new resources for joint use of existing interconnection capability are used to ensure that the total amount of interconnection service utilized remains the same.

Developers have noted that MISO's process for surplus is favorable as compared to other transmission service providers.[76] Because MISO enables resources to self-limit the degree of output, it disqualifies fewer requests from the ability to utilize surplus service. As an example, MISO studied the addition of 400 MW of wind generation at the existing Coal Creek coal plant and found there was no material modification for their surplus service.

ISO-NE enables interconnection customers to specify the amount of surplus service that exists, but includes limitations on utilizing the system capability associated with capacity resources. ISO-NE does allow for control technology to ensure that the output of multiple resources does not exceed the amount of the initial interconnection request.[77]

The current PJM process greatly limits the conditions under which surplus service is available. PJM pre-specifies a limited set of technologies and designs that would not materially system impact its system, requiring all other resource designs to enter the interconnection queue. PJM's process limits the sharing of energy or capacity interconnection capability between aging fossil plants that are rarely dispatched (or dispatched only during low renewable generation levels) and renewable generation or storage resources, excluding designs and technology combinations for which MISO makes fast-track options available.[78] PJM recently argued that surplus service offers little value due to study challenges associated with analyzing the surplus generating facility while preserving existing rights.[79]

CAISO has recently explained that customers do not often request to use surplus service in California because their study requirements do not oversize interconnection capacity relative to their specific needs. Therefore, CAISO asserts, "other interconnection customers cannot avail

73 MISO, Tariff Attachment X at § 3.2.3.

74 FERC NOPR, *Improvements to Generator Interconnection Procedures and Agreements* (June 16, 2022), Docket No. RM22-14, para 260.

75 MISO, *Generator Replacement Requests* (April 17, 2024).

76 FERC Order No. 2023, para 1429.

77 ISO-NE, Tariff Schedule 22 (LGIP) at § 3.3.

78 PJM, Manual 14G at § 1.9.

79 FERC Order No. 2023, para 1426.

themselves of any 'surplus' because it is already subscribed."[80] CAISO's argument may prevent more efficient use of existing capacity by multiple technologies, particularly where plants may be aging or used more infrequently.

### *2C.3. Recommended Improvements to Facility Replacement Processes*

To ensure that existing system capability can be efficiently transferred, we recommend that FERC enhance its surplus interconnection service to enable surplus resource interconnection rights to persist beyond the retirement of the existing resource. To ensure the seamless transfer of the initially shared system capability from existing resources to a new resource, FERC could require transmission providers to make headroom available where resources are facing reduced operations or retirement. Instead of segmenting surplus service from the generator replacement process, transmission providers should provide owners of retiring generators the option to continually use transmission capability through the transition to the new resource, enabled by removing the Order No. 845 limitation that units requesting surplus service can only operate for one year after the deactivation date of the host resource.[81]

Allowing indefinite sharing of existing transmission capability would avoid delaying the transition to aThe  new generator to the year of retirement. The current practice may result in higher consumer costs due to artificially elevating operational hours of inefficient units and potentially create reliability challenges due to higher maintenance cost thresholds. Instead, deactivation studies should consider the contribution of any new resources sharing system capability at the existing POI, which would persist after retirement of the existing generator. Such a process would not only facilitate the interconnection of new resources, but could also reduce the need for transmission upgrades associated with retiring generators.

With these improvements, sharing of interconnection service at existing POIs could become a more viable mechanism for allowing the interconnection of new clean resources while also allowing aging existing generating resources to continue to provide reliability value. For example, during times of high renewable generation, surplus renewable energy resources could be injected because during such periods the aging existing resource would be unlikely be dispatched. Conversely, during periods of low renewable output, the POI sharing arrangement would allow for the dispatch of the existing resource when needed to maintain grid reliability and supply adequacy. In addition, we envision that the control technologies and operating agreements utilized by the two generators would be designed to ensure the availability of interconnection service for the existing generator (e.g., to satisfy its ongoing capacity obligations to the system) while preventing the joint output of the generators from exceeding the POI's capability.

The availability of such an enhanced POI sharing and transfer option would further facilitate the interconnection of new resources, increase efficient use of the transmission system, improve

80 FERC Order No. 2023, para 1425.

81 FERC Order No. 2023, para. 1430. "Elevate contends that, although an interconnection customer taking surplus interconnection service may operate for up to a year following the original generating facility's retirement, a one-year period is too short when it may take four years or more to navigate the interconnection process. According to Elevate, a surplus interconnection customer should be able to operate sufficiently long following the original generating facility's retirement that it has the ability to obtain permanent interconnection service through the submission of a new interconnection request." (internal citations omitted)

generator replacement processes, and reduce or eliminate transmission upgrades otherwise identified as part of generator deactivation studies.

### REFORM 2D. Prioritize "most ready" interconnection requests for available headroom.

While a step in the right direction, Order No. 2023 readiness deposit and site control requirements are unlikely to present sufficient readiness requirements to developers to substantially reduce the volume of interconnection requests and allow for an efficient and workable interconnection study process. In adopting just the readiness deposit and site control requirements, FERC was persuaded that, "nonfinancial commercial readiness demonstrations … may not necessarily serve as appropriate indicators of a proposed generating facility's commercial viability on a *national basis.*"[82]

Given the overwhelming volume of interconnection requests and demand for new resources, available system headroom should be prioritized to the projects that can reach commercial operation most quickly. Accordingly, we recommend that transmission providers should prioritize competing interconnection requests in the fast-track processes recommended in Reform 2-B and 2-C based on an assessment of the interconnection requests that are "most ready" to proceed to construction.

Each transmission provider should adopt readiness criteria that reflect region-specific considerations for prioritizing those interconnection requests that are best positioned to come online in a timely fashion after executing an interconnection agreement. Transmission providers would then prioritize those requests that are ranked "most ready" based on the criteria up to the amount of available headroom. That headroom may exist in a well-defined location, as in the case of replacing a retiring unit, or it may be defined as broadly as a zonal cap on new resource additions based on proactively planned capacity.

Where prioritization is required, "most ready" scoring should provide flexibility to developers to allow them to determine, through a competitive process, the right level of readiness appropriate for making an interconnection request. Transmission providers benefit by avoiding the need to engage in contentious and potentially arbitrary decisions for establishing the exact readiness requirements that could achieve greater schedule and cost certainty.

Establishing an entry fee approach, as discussed in Reform 1, may be sufficient in some cases to attract only the interconnection requests ready to advance to construction, based on the assessment of the developer. However, for situations where the entry fee approach attracts interconnection capacity that exceeds the planning cap, the entry fee framework should

**Each transmission provider should adopt readiness criteria that reflect region-specific considerations for prioritizing those interconnection requests that are best positioned to come online in a timely fashion after executing an interconnection agreement.**

82 Emphasis added. FERC Order No. 2023, para 695.

also include a method to prioritize requests based on their readiness.

Alternative approaches to prioritizing interconnection requests are unlikely to achieve the goals for continued interconnection reform stated above. For example, transmission providers could continue to utilize a first-come, first-served approach for the interconnection requests that achieve Order No. 2023 readiness requirements up to pre-determined limits. However, this approach will not identify those requests that are "most ready" to be built and instead reward those that submit their requests earliest in the queue process. A first-come, first-served approach may even incentivize early submission of requests for projects that are relatively less ready to be built. Another potential approach for prioritizing requests is for transmission providers to further increase the readiness requirements to limit entry based on key development milestones, such as completion of permitting. However, administratively choosing an ideal readiness threshold is likely to be difficult and may overshoot the willingness of developers to submit requests.

### *Evidence from MISO that prioritization is necessary*

Order No. 2023 requires transmission providers to establish higher study deposit amounts, demonstrate 90% site control at the time of their request, and show 100% site control at the time of executing the facilities study agreement. However, there is already evidence that these more stringent readiness requirements will be insufficient to limit entry into the interconnection process. The MISO DPP-2023 cluster study requirements exceed those specified in Order No. 2023, including 100% site control for the resource and 50% for the generation tie-line at the time of the request, and a higher entry payment of $8,000/MW than other transmission providers.[83] Despite these requirements, MISO received 123 GW of interconnection requests, about the same capacity as its entire regional peak load, for the DPP-2023 cluster study.[84]

### *Most-ready prioritization criteria*

We recommend that the transmission provider and its stakeholders set prioritization criteria best suited to the Region and score interconnection requests based on those criteria. For establishing the criteria, transmission providers should assess the primary non-interconnection aspects of resource development in their service area that limit readiness to build after executing interconnection agreements and set their criteria to assess which requests are best positioned to overcome those challenges. For example, LBNL research shows that limiting factors beyond the interconnection process are commercial viability of the new resources, the pace at which permitting and siting authorities can approve the projects, and community opposition.[85]

Once these criteria are established, developers will then choose how far to develop their projects before submitting the project into the interconnection process, and competition amongst the developers will determine how advanced interconnection requests will need to be to access the available headroom.

---

83 Savion, *MISO GI Queue Size Management Alternative* (June 2024), MISO IPWG.

84 MISO, *MISO Generator Interconnection, 2023 Queue Cycle: Requests Overview* (April 23, 2024).

85 Robi Nilson, Ben Hoen and Joe Rand, *Survey of Utility-Scale Wind and Solar Developers Report* (January 2024), Lawrence Berkeley National Laboratory.

### *2D.1. Examples of Various Prioritization Approaches*

Several transmission providers have recently developed proposals for setting limits on capacity studied in the interconnection process. These approaches explore different ideas for raising the readiness requirements for new resources seeking interconnection, going beyond the requirements of Order No. 2023.

#### *CAISO: Scoring-based prioritization*

CAISO is preparing to file Track 2 of its interconnection reforms with FERC. These reforms would set a limit on the capacity that can request interconnection within a given zone to 150% of the planned deliverable capacity based on the most recent transmission planning study. CAISO then prioritizes interconnection requests using a scoring system to assess the readiness of the requests to move to construction. As discussed in Appendix 2.1.2, CAISO scores requests based on three metrics: c*ommercial interest (30%), project viability (35%), and system need (35%).* The determination of the appropriate readiness criteria has resulted in significant disagreement amongst stakeholders, demonstrating the challenges of administratively specifying the criteria for identifying the "most ready" interconnection requests. CAISO includes a Merchant Deliverability Option (previously known as Option B) in which projects can request interconnection at locations on the system without available capacity but will forgo reimbursement and must pay for their own upgrades by electing to forego system funding.

#### *SPP: Entry Fee-based prioritization*

SPP is proposing to consolidate its interconnection process with its transmission planning process. In its Consolidated Planning Process (CPP), SPP proposes to limit the capacity that can request interconnection in any given year to (1) 100% of the planned capacity by zone and subzone included in its most recent long-term planning process and (2) developers' willingness to pay the entire pre-determined entry fee for new interconnections. The entry fee will be based on the full costs allocated to generation interconnection from the consolidated planning process plus the cost of local attachment facilities identified in the interconnection study process, as discussed in Reform 1 and Appendix 2.4.

SPP proposes that interconnection requests will also have to meet readiness requirements; if these are met, then SPP will accept requests on a first-come, first-served basis. SPP intends that the entry fee (based on full interconnection costs) is sufficiently high to deter interconnection requests from projects with less-certain economics and also delays interconnection requests until projects are nearer to construction (thus having made substantial progress through permitting processes). For example, while recent security deposits for interconnection studies in SPP and other transmission providers are about $4-8 per kW, full interconnection costs tend to be about $50–150 per kW on average. Thus, charging entry fees based on the full (allocated) interconnection costs likely will limit interconnection requests to projects that can quickly move to construction without the need to rely primarily on readiness rankings.

#### *Rte (France): First-ready, first-served using posted zone-specific interconnection costs*

Rte limits interconnection requests to resources that are both fully permitted and willing to pay the pre-set interconnection fee, thereby significantly de-risking and accelerating the interconnection process. Once permitted, projects are allocated headroom in the order of application. If no headroom is available, interconnection customers must wait until Rte makes additional headroom available.

Rte's proactive planning process to build capacity on its lower voltage system (where the majority of renewable resources are developed) is based on zonal shares of a nation-wide target for annual renewable energy additions. The nationwide target is allocated to individual planning zones, for which sufficient headroom is then planned and constructed at locations identified based on input from local governments and resource developers. Similar to SPP's entry fee approach, Rte posts the amount of available capacity and the uniform zone-specific costs for interconnecting at the locations where headroom will be created.

### *MISO: First-come, first-served capacity cap*

MISO is proposing to limit entry into the interconnection study process without setting any priorities, using a cluster study capacity cap. MISO proposes to require interconnection customers to demonstrate 100 percent site control at application for the generation facility footprint and 50 percent site control for the generation tie-line. MISO's FERC-approved financial deposit at application (milestone M2) is $8 per kW, which is double the commitment required by other transmission service providers. More controversially, MISO proposes to set a hard cap, limiting the total quantity of requests to a percentage of demand (e.g., 50 percent of the peak demand within a given planning zone).[87] This approach addresses the need to limit entry to allow for a more workable interconnection study process, but would not link the interconnection process to the available system capacity created by the multi-value projects identified through its Long-term Regional Transmission Planning (LRTP) process (as is the case for SPP, CAISO, and Rte). As discussed in Appendix 2.3.2, MISO's proposal has been found by FERC to be discriminatory and is being resubmitted in a modified form.

### *Comparison of prioritization approaches*

The proposed SPP and Rte approaches are similar. In each case, interconnection capability is proactively created for new resources and a zonal interconnection cost for resources up to the planned interconnection capacity is determined. SPP's proposal includes an additional step in which it studies the need for local interconnection facilities with costs assigned to the interconnection customer.[86] The requirements on the interconnection customer to claim available capacity include the completion of required permitting (Rte) and developers' willingness to pay the upfront interconnection capital costs (both Rte and SPP). The total capacity able to interconnect in a given period and zone is 100 percent of the planned interconnection quantity. Notably, the SPP entry fee framework is still in development with several key aspects of the process remaining outstanding, including applying additional readiness criteria, approaches to mitigate changes in costs for new transmission facilities (see Section 1.3), and the approach to determining how much new capacity, of what types, to include in transmission planning studies.

---

86 An important consideration for SPP will be whether the entry fee is based on the total zonal and subzonal transmission costs, or a subset of costs for upgrades intended to support interconnection (net of other benefits the upgrades provide).

These approaches differ from CAISO in a few important ways. CAISO's approach does not allocate costs of upgrades from the transmission planning process to interconnection customers, such that the interconnection costs for generators will be significantly lower and, thus, will not be a sufficient deterrent for projects with less-certain economics to request interconnection. Instead, CAISO will cap requests studied in each cluster study at 150% of the available planned capacity and score requests based on their readiness ranking, similar to the first approach proposed above. Allowing more than 100% planned capacity to enter the interconnection study process can introduce additional cost and schedule risk to the interconnection process relative to SPP's approach.

Still, the impact (in terms of cost and schedule) of a process that allows more than 100% planned capacity is not likely to be as significant as the impact of a process without proactive planning or any limits on queue volume. Allowing generation capacity to enter the interconnection process in excess of the planned increase in grid capacity creates an opportunity to take advantage of any additional capacity that may become available due to the lumpy nature of network upgrades.

**REFORM 3**

# EFFICIENCY

*Optimize the interconnection study process.*

Interconnection studies are essential analyses for transmission providers to ensure the reliable delivery of new and existing resources to serve load. However, transmission providers currently take an overly conservative approach to studying system impacts of interconnection requests, resulting in a study process that is unnecessarily complex, resource-intensive, and prone to delays.

Under current practices, interconnection studies in many cases can trigger network upgrades that do not reflect the requested level of interconnection service and are not required to maintain system reliability given how system operators manage the grid in real-time. In addition, transmission providers often exclude existing and emerging technologies that can support reliable operations at a lower cost. These practices not only burden interconnection customers (and ultimately electricity customers) with unnecessary costs, but are also an inefficient and ineffective means to plan and build transmission upgrades and to bring new, needed resources online.

Order No. 2023 made significant progress towards reforming interconnection studies by requiring the adoption of cluster studies, firm study deadlines, penalties for transmission providers that fail to complete interconnection studies on time, and consideration of alternative transmission technologies. While these changes will improve interconnection study processes, the Order falls short of pursuing the full suite of available best practices to comprehensively improve study processes.

We recommend five further reforms, not specifically required by FERC, that transmission providers should pursue to improve the interconnection study process. The reforms target improvements to the interconnection study process to increase the system headroom considered to be “available” for interconnecting new resources and also identifies reforms necessary to make the study process more efficient.

If not adopted by transmission providers, FERC should evaluate and potentially impose similar requirements as part of future reform efforts. Together, these reforms can streamline access for the interconnection customers and reduce the total costs to ratepayers.

### REFORM 3A. Identify only network upgrades that are consistent with the requested interconnection service level.

Interconnection studies can be enhanced by identifying only those transmission upgrades that are focused on the specific level of interconnection service (e.g., ERIS, NRIS, etc.) requested by the interconnection customer. Today, there is wide variation in the study methods and criteria underlying different types of firm and non-firm interconnection requests in various regions, resulting in higher costs and increasing schedule uncertainty.

FERC has expressed a desire for consistency in modeling standards across regions.[87] In Order No. 2023, FERC encouraged consistency in study procedures relating to interregional affected system studies, but did not pursue additional reforms related to further standardization of underlying interconnection study assumptions or methods,[88] setting the stage for future reforms beyond Order No. 2023.

To achieve greater consistency in modeling standards across regions, we recommend that FERC hold a technical conference to document current study approaches across transmission providers and identify differences in study procedures. Following that conference, study procedures for “as available” (ERIS) and firm (NRIS) interconnection service should be updated to achieve FERC’s original intentions for those services. Further, we recommend that FERC apply transparency and replicability standards to generator interconnection study processes similar to those that have governed regional transmission planning since Order 890.

#### *3A.1. Current NRIS and ERIS Study Practices*

Current interconnection study assumptions ostensibly support the Commission’s two levels of interconnection service, Energy Resource Interconnection Service (ERIS) and Network Resource Interconnection Service (NRIS).[89] These two levels of service are meant to serve distinct functions: ERIS provides interconnecting resources non-firm service that creates eligibility “to deliver its output using the existing firm or non-firm capacity of the Transmission System on an

> **In Order No. 2023, FERC encouraged consistency in study procedures relating to interregional affected system studies, but did not pursue additional reforms related to further standardization of underlying interconnection study assumptions or methods …**

87 FERC Order No. 2023, para. 1261.

88 FERC Order No. 2023, para. 1281.

89 FERC, *Order No. 2003: Standardization of Generator Interconnection Agreements and Procedures,* Henceforth: “FERC, Order No, 2003,” (July 24, 2003).

‘as available’ basis;” and NRIS provides firm service integrating resources “into the Transmission System in a manner comparable to that in which the Transmission Provider integrates its own generators to serve native load customers.”[90] To achieve these various service levels, Order No. 2003 specified distinct study requirements for ERIS and NRIS,[91] which the Commission recognized in Order No. 2023.[92]

In practice, the distinction between ERIS and NRIS has been inconsistently applied across transmission providers, creating additional obstacles—particularly for resources seeking to access the “as-available” ERIS option envisioned by FERC’s regulations.[93] As summarized in the *Generator Interconnection Scorecard*, various transmission providers handle ERIS in contrary, and at times opposite ways.[94] These differences can include the method of dispatching down energy-only resources under study, the method of redispatching existing resources in the power flow model, the specific scenarios and injection levels tested (e.g., summer, winter, light-load, other), the contingencies considered in these scenarios, or the minimum distribution factor cutoff that identifies ERIS resources as contributing to network upgrades.[95]

When inconsistent and overly stringent criteria are applied to ERIS requests, interconnection studies are delayed and ERIS customers are required to finance major system upgrades that are likely unnecessary for the requested non-firm level of transmission service. Where only modest differences exist in the study methodology between (non-firm) ERIS and (firm) NRIS, ERIS is no longer a commercially sensible interconnection option. As a result, in Regions with available data, interconnection customers request ERIS interconnections for only 9 percent of total capacity requests, defeating the goal of providing differentiation in service levels set forth in Order No. 2003.[96]

Further, many of today’s ERIS studies do not consider economic dispatch to manage network constraints. Instead, they simply rely on power flow models that represent only a snapshot of the physical flows on the grid and are based on static dispatch assumptions. These power flow models rebalance the system after the addition of a new generator by dispatching down existing generators on a pro-rata basis, often throughout the entire Region. When the power flow model is balanced in this way (which has no relation to economic dispatch or how the system would actually be dispatched), the injections from the new generators take the place of the “turned down” generators, creating power flows that are broadly distributed across the regional footprint.

90 FERC Order No. 2003, para. 753, 754.

91 FERC Order No. 2003, para 784.

92 “Specifically, a transmission provider studying generating facility for NRIS would study the transmission system at peak load, under a variety of severely stressed conditions to determine whether, with the generating facility operating at full output, the aggregate of generation in the local area can be delivered to the aggregate of load, consistent with reliability criteria and procedures.” FERC Order No. 2023, n. 2365. Citing Order No. 2003 at para 768 and Order No. 2003-A, para 500.

93 To emphasize the non-firm nature of ERIS, Order No. 2003 noted that ERIS “Interconnection Studies would identify the maximum allowed output of the Generating Facility without Network Upgrades.” FERC Order No. 2003, para 753.

94 Interconnection Scorecard, pp. 58-60.

95 Enel, *Initial Comments*, Docket RM22-14, pp. 25-26, n. 27; Noting that SPP and PJM interconnection study processes take “almost the exact opposite approach.” Citing: K. Chilukuri, A. Vander Vorst, *Interconnection Study Criteria* (May 31st, 2022), *ESIG Special Topic Webinar*. Henceforth, “ESIG Interconnection Webinar.”

96 Interconnection Scorecard, p. 60.

Where an ERIS study models such widely dispersed injections without consideration of market-based congestion management, the study can identify distant reliability violations that will not actually occur when congestion is managed during real-time operations. For example, PJM assumes that incremental injections of new offshore wind in Maryland reduce generation dispatch in Illinois. The resulting power flows (and possible overloads) on all transmission facilities between Maryland and Illinois is unlikely in actual operations, as the overload of distant facilities would be avoided through market-based congestion management. This inflexible dispatch approach is often applied to both ERIS and NRIS studies today, even though it was specifically envisioned by FERC to be required for only NRIS-level service.[97]

### *3A.2. Restoring ERIS Viability by Implementing Economic Re-Dispatch in Studies*

While FERC acknowledged the use of varying ERIS assumptions across transmission providers in Order No. 2023, it specifically declined to require uniform standards or impose "consistent, uniform thresholds to measure impact" of ERIS and NRIS requests, beyond limited changes to interregional affected system studies.[98] Transmission providers or FERC should restore the viability of ERIS as an "as available" service as envisioned in Order No. 2003, without the study of contingencies appropriately evaluated for NRIS interconnection requests.

To restore the viability of ERIS, transmission providers should update interconnection study methods to balance power flow models in a way that accounts for likely market dispatch and the non-firm level of ERIS requests.[99] New power flow modeling tools can approximate a market-based generation dispatch within the power flow case to identify only reliability violations that could not be avoided by market-based congestion management.[100] Such an approach would be consistent with the NERC standard underlying the development of generator interconnection studies (TPL-001-4), which allows for re-dispatch of generation to resolve identified violations.[101]

Implementing this approach in ERIS studies will require standardization and refinement of several technical aspects of the power flow analyses and models used in interconnection studies across transmission providers. FERC should hold a technical conference to document current ERIS study approaches across transmission providers and identify differences in study procedures.[102]

97 "By contrast, the study for Network Resource Interconnection Service includes similar analyses but also assumes that the output of the Generating Facility may displace the output of certain other Network Resources on the Transmission System. The study then identifies the Network Upgrades that would be required to allow the Generating Facility to be counted toward system capacity needs in the same manner as the displaced resources." FERC Order No. 2003, para 784.

98 "The Commission noted that, while this proposal would standardize the use of ERIS for affected system studies, individual transmission providers use different specific thresholds for ERIS studies." FERC Order No. 2023, para 463.

99 Additional recommendations to improve the viability of ERIS and other interconnection process reforms are discussed here: Norris, Tyler H. Beyond Order 2023, Considerations on Deep Interconnection Reform, (August 2023), Duke University, Nicholas Institute for Energy, Environment & Sustainability

100 For example, Power Gem's power flow model Tara can approximate a market-based generation dispatch.

101 See, e.g., ESIG Interconnection Webinar, citing NERC TPL-001-4 at Table 1. ("Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.")

102 "[T]he Commission could solicit information from transmission providers documenting what assumptions and processes are used for ERIS and NRIS, respectively, to provide a starting point for dialogue around what study assumptions may be appropriate." FERC Order No. 2023, Commission Clements concurrence, para 30.

To update ERIS study methods, we recommend the following approach:

- Standardize injection levels considered in interconnection study models to be consistent with applicable generation profiles for each power flow study case; [103]
- Consider economic re-dispatch for ERIS resources (consistent with NERC standards and market-based congestion management practices);
- Test only contingencies applicable to "as available" (non-firm) ERIS, including the ability to dispatch down (curtail) the ERIS resource itself;
- Raise ERIS minimum DFAX thresholds to reflect "as-available" service levels; and
- Enable ERIS resources to request an upgrade to NRIS in the future.[104]

Among the study procedures reviewed, special attention should be given to divergent distribution factor (DFAX) thresholds across transmission owners, which are used to determine whether or not an interconnection customer is assigned costs for solving an identified violation.[105]

Given FERC's desire to "create consistency in the modeling standards used across all transmission regions," and the relative importance of modeling procedures in identifying responsibility for network upgrades and in the feasibility of ERIS options, FERC should prioritize the above reforms in future interconnection initiatives.[106] Developing a record regarding current ERIS offerings will lay a strong foundation for FERC to ensure availability of ERIS, improve interconnection timelines, and advance competition by enabling streamlined access to the transmission system.

### *3A.3. Improve NRIS Studies by Considering Limited Economic Re-Dispatch*

Economic re-dispatch options should also be reconsidered for NRIS requests, as long as the redispatch does not reduce the dispatch of resources below their capacity accreditations or associated firm injection rights. To ensure reliable delivery of NRIS requests within a defined capacity or deliverability zone, study methods should ensure that local re-dispatch is not used if it constrains the deliverability of both existing and new resources to meet their capacity obligations. Transmission providers should also account for the allowable redispatch of the system to avoid upgrades when testing for P3 (N-G-1) and P6 (N-1-1) contingencies for NRIS requests.

### *3A.4. Establish Transparency and Replicability Standards to Interconnection Studies*

We recommend that FERC apply transparency and replicability standards to interconnection study processes similar to those that have governed regional transmission planning since

---

103 ESIG Interconnection Webinar.

104 Streamlined requirements of and greater access to ERIS should not preclude generating resources from subsequently requesting NRIS service (and, if applicable, paying for any upgrades necessary to provide the firm service).

105 Based on the study procedures and contingencies discussed above, power flow studies are likely to identify specific violations based on the cluster of resources seeking system interconnection. DFAX analysis enables transmission providers to analyze how much flow each generating resource is contributing to each identified violation. The DFAX contribution of a specific queued generator, expressed in percentage terms (percentage contribution to the violation), often dictate whether an interconnection customer is assigned a portion of cost for solving the identified violation.

106 FERC Order No. 2023, para 1261. (Internal citations omitted.)

Order No. 890.[107] Applying these standards would require transmission providers to "reduce to writing and make available the basic methodology, criteria, and processes they use to develop their" interconnection studies, as well as make available the "basic criteria, assumptions, and data that underlie" their models.[108] This standard would need to be implemented to enable an "independent third party to replicate the results of planning studies and thereby reduce the incidence of after-the-fact disputes."[109] In practice, the release of these data, models, methodology, contingencies, and assumptions would occur at the conclusion of each cluster cycle under the Order No. 2023 process to ensure consistent and sufficient data sharing. Such provision of data would reduce disputes with customers in the queue, provide data to future customers seeking to enter the queue, and could reduce the ongoing "information asymmetry" that will only partially be addressed by Order No. 2023.[110]

### REFORM 3B. Identify the most cost-effective solutions for resolving reliability violations.

To the extent that generation interconnection requests or proactive transmission planning identify transmission constraints, the solutions selected to address the identified transmission need should include the full set of commercially available and reliable options. Given the increasing interconnection-related costs and delays, we recommend that transmission providers include for potential selection an expanded set of cost-effective transmission solutions that can be implemented quickly.

The set of solutions should include those technologies that can reliably increase the utilization of the existing grid (often referred to as "grid-enhancing technologies" or GETs), such as "limited impact" remedial action schemes, topology optimization, power flow control devices, dynamic line ratings, and transmission-focused storage applications. The solutions should also include those that upgrade constrained existing lines through advanced transmission technologies, such as reconductoring the lines with advanced conductors, rebuilding the lines at higher voltage levels, converting them to high-capacity HVDC lines, or adding superconducting wires (once commercially available).[111]

Order No. 2023 highlighted the value that GETs can provide to the interconnection process, but only requires that GETs be "considered" and does not preclude transmission service providers from rejecting GET solutions simply because grid operators prefer not to rely on them. Some solutions, such as dynamic line ratings (DLR), may be rejected because they may not add "firm" capacity to the grid, such as during heat waves. But since DLRs can substantially increase the available transfer capability during most hours of the year, DLRs can offer very cost-effective solutions for the "as available" ERIS option that can be implemented in less than a year, as discussed in Section 3-A.2. Other grid enhancing and advance transmission technologies can offer cost-effective solutions to address both ERIS and NRIS transmission needs.

107 FERC Order No. 890.

108 See, e.g., FERC Order No. 890, para 471.

109 FERC Order No. 890, para 471.

110 See e.g. FERC Order No. 2023 at n. 129, citing Google initial RM21-17 comments at 4.

111 Because of higher cost and delays associated with new greenfield transmission solutions, the CETWG recommends that transmission solutions be based on "loading order approach" to more quickly and cost effectively utilize the existing grid and right of ways. "[B]efore grid expansion through new transmission lines is considered, RAS could be used first to create additional interconnection headroom, grid optimizing technology would be used next to increase interconnection headroom through optimization of the grid, followed by increasing the capacity of existing lines and existing rights of way." Massachusetts Clean Energy Transmission Working Group (CETWG), Report to the Legislature (December 2023), pp. 51-52.

Yet, transmission service providers may reject these options as "not preferred" for addressing grid-planning and generator-interconnection related needs. For example, PJM does not prefer solutions based on GETs, such as power flow control devices, when conventional solutions are available. As a result, PJM typically rejects GETs solutions that could reliably address identified interconnection needs even if they are lower cost and can be implemented more quickly.[112]

An additional example of solutions that allow for reliable and cost-effective utilization of the existing grid are remedial action schemes (RAS), also referred to as system protection schemes (SPS) or "run-back schemes." RAS are reliable automated grid responses that avoid overloads during contingency conditions by triggering immediate remedial actions. For example, if one of two parallel transmission lines carrying power flows from a generator to loads would be overloaded during an outage of the second line, standard N-1 contingency planning would limit flows on those lines to the capability of a single line (i.e., the contingency limit). To utilize the capability of both lines, an automated RAS response can be implemented that will instantaneously reduce the output of the generator during the contingency event (i.e., the outage of one of the lines) to avoid the overload and allow greater flows from the generators under normal conditions (i.e., without a line outage). RAS are widely used in the western U.S., Canada, and internationally, but are generally rejected as solutions by grid operators in the eastern U.S.[113]

Experience shows that RAS can quickly, inexpensively, reliably, and dramatically increase the capability of the existing grid. For example, CAISO's reliance on RAS has created 21,000 MW of interconnection headroom, 16,000 MW of which are firm deliverable capacity.[114] CAISO states that RAS can "normally be implemented much more quickly and at a much lower cost than constructing new infrastructure" and "increase the utilization of the existing transmission facilities, make better use of scarce transmission resources and maintain system reliability."[115]

To ensure that complex and poorly designed RAS cannot cause reliability concerns, CAISO and other grid operators in Australia and Europe have established RAS guidelines and standards. For example, CAISO uses a stakeholder-driven process to "ensure that performance of all RASs are consistent across the ISO controlled grid."[116] RAS can be as simple as automatically reducing the output of a resource during an outage of a specific transmission line that would otherwise create a contingency-related overload. In fact, CAISO's RAS guidelines require each RAS to be "simple and manageable" and specifies design features to maintain reliable operations, including limits on the contingencies that trigger a RAS, the system elements monitored by the

112 For example, in addressing offshore wind generator interconnection needs for New Jersey's State Agreement Approach (SAA), PJM chose a $16 million reconductoring solution over a $5 million smartwire solution, because "flow control devices are not preferred when conventional transmission solutions are available." PJM further clarified that: "Where there are acceptable conventional solutions and where the additional transmission capacity offered by conventional solutions are extensive compared to cost savings of adopting power flow control devices, PJM will generally prioritize consideration of the conventional solutions. Power flow controlling devices, such as phase angle regulators and SmartWire devices, were proposed in this window. Such devices are generally not preferred solutions but may be considered when there is no other transmission solution within an order of magnitude cost of the power flow controlling device." PJM, *Reliability Analysis Report: 2021 SAA Proposal Window to Support NJ OSW* (September 19, 2022).

113 TenneT, the Dutch-German grid operator, uses RAS to address contingency overloads that would otherwise be associated with the full outage of a 2,000 MW bi-pole HVDC line. See Brattle Group, *The Operational and Market Benefits of HVDC to System Operators*, p. 89. Similarly, Manitoba Hydro and Nova Scotia Power rely on a runback scheme for HVDC lines to prevent the overloading of AC lines during critical contingencies. *Id.*, pp. 110-114. The Australian Energy Market Operator also uses RAS to address contingencies. AEMO, *Australian Remedial Action Scheme Guidelines*. The organization of European grid operators (ENTSO-E) guidelines for remedial actions can be found here and here.

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

115 CAISO, *California ISO Planning Standards* (February 2, 2023), p. 11. Henceforth, "CAISO Planning Standards."

116 CAISO Planning Standards, p. 11.

RAS, and the number of RAS monitoring the same elements or contingencies.[117]

While RAS are not a preferred solution to address long-term needs by eastern U.S. power market regions, the wide use of RAS in the western U.S. (including CAISO) and internationally demonstrates that well-designed RAS offer cost effective solutions for addressing generator interconnection and other transmission needs. Their wide-spread utilization in the western U.S. also means that well-designed RAS are consistent with NERC reliability standards.[118]

### REFORM 3C. More closely align data inputs, assumptions, and process timing between interconnection study processes of different local and regional scope.

The lack of alignment in study practices between regional transmission providers and local transmission owners, and between host systems and neighboring affected systems, results in uncertainty for interconnection customers. We recommend that FERC, Regions, and transmission providers take further action to more closely align data inputs, assumptions, and process timing between interconnection study processes. While there are some aspects of study practices that reasonably vary from location to location, much stronger alignment is needed in both directions: local to regional and host system to affected system.

**While there are some aspects of study practices that reasonably vary from location to location, much stronger alignment is needed in both directions: local to regional and host system to affected system.**

#### *3C.1. Lack of alignment between local and regional interconnection study practices*

Interconnection study practices are often not aligned between the Regions and transmission owners within those Regions, as discussed in the *Generation Interconnection Scorecard. FERC has already addressed this lack of alignment in the context of transmission planning in Order No. 1920 but did not address this issue in Order No. 2023 for interconnection studies.*

*In Order No. 1920, FERC found a "need for reform of the local transmission planning process and coordination between the local and regional transmission planning processes."*[119] Interviews with interconnection customers suggest that its findings regarding transmission planning processes apply equally to interconnection study practices. In explaining what it meant by a "need for reform of the local transmission planning process," FERC found:

- "[L]ocal transmission planning processes lack adequate provisions for transparency and meaningful input from stakeholders;"
- "[T]he absence of minimal standards or specified procedures to implement the transmission planning principles required by Order No. 890;"

117 CAISO Planning Standards, pp. 12-14.

118 For example, see: CAISO, *PRC-012 Remedial Action Schemes*, v1.1 (January 18, 2024).

119 Although FERC acknowledged these alignment issues, Order No. 1920 only required additional transparency at the local level. FERC Order No. 1920, para. 1569.

- "[A]dditional coordination between the local and regional transmission planning processes regarding replacement of aging infrastructure is needed;" and
- "[T]ransmission providers … are not consistently evaluating whether … replacement transmission facilities could be modified (i.e., right-sized) to more efficiently or cost-effectively address transmission needs."[120]

In at least some of the Regions, similar differences in interconnection study practices exist. The degree of difference is difficult to assess: We were unable to locate a summary of the differences between Regional and local planning criteria for the Regions, even for those where we were aware of local planning requirements that differed from those used by the Region. Yet the impact of these differences on interconnection requests was not addressed in Order No. 2023, as FERC found that the request to harmonize study standards and assumptions was outside the scope of that proceeding.[121]

### *3C.2. Lack of alignment between host system and affected system interconnection study practices*

In Order No. 2023, FERC updated the required scope of affected system studies to be "consistent with the scope of host system interconnection studies"[122] and imposed standard affected system study delay penalties.[123] FERC also required that affected system studies use the ERIS modeling standard.[124]

While Order No. 2023's reforms address many of the concerns expressed by interconnection customers about affected system studies, as noted above, FERC did not attempt to harmonize study standards and assumptions between Regions and transmission owners or across transmission providers, even on a regional basis. For example, Order No. 2023 retains the right of each transmission provider to determine its own implementation of the ERIS modeling standard.[125] Nor did FERC require either host or affected system transmission owners to coordinate study activities, although it did encourage voluntary coordination such as through filing seams agreements under FPA section 205.[126]

Order No. 2023 also partially addressed the impact on interconnection customers when affected system studies identify additional upgrades after an interconnection agreement has been executed with the host system – a late and particularly unwelcome increase in the customer's network upgrade costs.[127] FERC did not (or could not) mitigate all circumstances in which delayed affected system studies conflict with a host system's readiness to execute an interconnection agreement. While hosts may delay agreement execution because of an affected system study, delay is not allowed if it would cause a material impact on the cost or timing of other customers' agreements. In those circumstances, the interconnection customer must either accept an agreement without knowing its full costs or it must allow the agreement to be filed with FERC, unexecuted.

120 FERC Order No. 1920, paras. 1569-1577.
121 FERC Order No. 2023, paras. 183, 1291 1507.
122 FERC Order No. 2023, paras. 1160, 1190.
123 FERC Order No. 2023, para. 962.
124 FERC Order No. 2023, paras. 1151, 1170, 1276-1280.
125 FERC Order No. 2023, para. 1286.
126 FERC Order No. 2023, para. 1172.
127 FERC Order No. 1920, paras. 1125, 1174.

Those circumstances are particularly concerning where the affected system is a non-public utility transmission provider, since FERC lacks jurisdiction to impose firm deadlines, requirements and delay penalties on non-public utilities.[128] With respect to this jurisdictional constraint, it appears that interconnection customers will have to consider the schedule and cost risks associated with potential impacts on non-public utilities in determining whether to enter and proceed through the queue.

### *3C.3. Experience with alignment of study practices across transmission systems*

The two best examples of alignment of study practices across transmission systems are from CAISO and the Florida Reliability Coordinating Council (FRCC). CAISO and the California Public Utilities Commission (CPUC) have each taken steps to direct alignment in interconnection study practices. In FRCC, transmission owners have voluntarily established a common process for evaluating interconnection service requests.

#### *CAISO*

CAISO policy results in significant alignment in the study practices of the transmission owners in the state,[129] including generators,[130] and the maximum cost responsibility for interconnection customers across all transmission owners.[131]

Although it does not directly regulate interconnection or transmission study practices, the CPUC recently established the Transmission Project Review process to address fragmented recordkeeping on transmission projects that failed to provide information needed by interconnection customers. By integrating all transmission providers' system transmission planning projects and interconnection-related network upgrades in a single reporting framework, study practices could become better aligned, at least in terms of more consistent reporting standards.

#### *Florida Reliability Coordinating Council (FRCC)*

The FRCC has established a common reliability evaluation process for interconnection requests.[132] For example, all host systems rely on FRCC's performance and screening criteria and the same contingency list. When evaluating an interconnection request, if the criteria for an affected system are exceeded, then the affected system is contacted.

An affected system may or may not require a study; for example, the affected system may already be aware of the problem and have an identified solution. If the affected system decides to do its own study, the main difference between the two studies is the cases that are modeled, such as different peak or low load conditions. In Florida, the peak season or low load conditions that place stress on one system may be different in the neighboring system, resulting in some

128 FERC Order No. 2023, paras. 962, 1175.

129 CAISO, *Dynamic Model Review Guideline for Inverter Based Interconnection Requests* (June 2, 2021).

130 CAISO, *Evaluation of Generator Reactive Capability* (October 4, 2019).

131 CAISO, *Network Upgrades and Cost Responsibility Implementation* (October 23, 2019). Cost guides can be found here.

132 Florida Reliability Coordinating Council, Inc., *Reliability Evaluation Process for Generator and Transmission Service Requests,* FRCC-MS-PL-054 (October 6, 2020). Assistance with interpretation of this document was provided in an interview with a former FRCC staff member with relevant job responsibilities.

systems choosing to study different load scenarios in addition to FRCC's common scenarios. These differences only become relevant when the new interconnection request appears to have a potential for impacts on another system.

Even though the FRCC common reliability process achieves a high degree of harmonization across its members, differences in the proposed network upgrades between the two systems may arise. A common reason for this is that an affected system may prefer not to use an available redispatch solution because of a firm supply commitment. Transmission providers negotiate between themselves to resolve differences of opinion over upgrades or redispatch solutions. Where a transmission provider has a financial relationship with the interconnection customer (up to and including being the same entity), the transmission provider is highly motivated to advocate for a good outcome for the interconnection customer with the affected system.[133] In other regions where transmission providers tend to have no financial relationship with the host system, the host system may provide little or no support to the interconnection customer.[134]

### 3C.4. Aligning host system, affected system and Regional study practices

Two recent reforms adopted by FERC provide a basis for further action to align host system, affected system and Regional study practices. In Order No. 2023, FERC found that "standardization of affected system study assumptions through ERIS modeling criteria will further simplify both affected system studies and restudies."[135] However, FERC has not required fully standardizing interconnection study practices. Building on the findings and approaches in Orders No. 2023 and No. 1920, FERC could adopt a standardization directive to address study practice alignment issues, as follows.

- **Align local study practices with the Region (where relevant):** Transmission owners should be required to use the Region's system integration study criteria, models, and assumptions to determine network upgrades that it will assign to the interconnection request(s) in its facility study, except as provided below.
- **Align affected system study practices with the host system:** The affected system should be required to use the host system's facility study criteria, models, and assumptions to determine network upgrades that it will assign to the interconnection request(s) in its facility study, except as provided below.

Aligning study criteria, models, and assumptions will further reduce the risk of "sticker shock" due to identification of additional network upgrade projects beyond those identified in system interconnection studies.[136] Key to this alignment is assigning the responsibility for determining the most effective and efficient upgrades to address system contingencies and costs to the owner of the transmission system where the contingency occurs. For example, an affected

133 In Florida, nearly all interconnection customers have been affiliates or otherwise sponsored by an affiliate of the transmission provider.

134 Interconnection Scorecard, p. 31.

135 FERC Order No. 2023, para. 1170.

136 This recommendation goes beyond the i2X Report's recommendation for voluntary, proactive collaboration on affected system studies. i2X Report, Solution 2.7, p. 33. While such collaboration may occur and could result in meaningful improvements, the persistence of differences in study practices that do not result in meaningful service protections results in unjustified costs and delays during the interconnection study process itself. According to interconnection customers, inconsistency in practices results in increased business risk and network upgrade costs.

system should not be able to require a specific upgrade be completed on another system – if the host system determines that the identified contingency is addressed by an upgrade, the affected system should accept that determination. However, it does not appear to be necessary to require alignment of cost estimating methods — since the responsibility for the cost estimate for each upgrade is clearly assigned to the transmission provider that owns the facility, each transmission provider can continue to use its own cost estimating methods.

If FERC does not adopt a standardization directive, such as the one described above, the Regions and transmission owners should do so within their own authorities.

### *Differences that should continue to be allowed*

Even though most of study criteria, models, and assumptions should be aligned, it should remain reasonable for local or affected systems to perform their own studies. Each system should be allowed to use its own study scenario(s), reflecting varying load considerations, as demonstrated by FRCC's study practices (Section 3-C.3). Allowing these types of variations would be consistent with FERC's finding in Order No. 2023 that regional flexibility in the variation in scenarios that transmission providers study is warranted.[137]

Furthermore, differing studies may be necessary because the local or affected system has more granular information in its study about its own system. To accommodate such conditions, transmission owners could be allowed to apply their own study criteria, models and assumptions as long as the result does not increase the cost by more than a predetermined threshold or where a transmission owner can demonstrate factual or service differences that justify variation.

In the first case, if by using those practices the transmission owner's facility study – or affected system study — results in contingencies that require network upgrades costing less than some threshold (e.g., 15% above the cost from the Region's – or host system's – study), then it could be allowed to require that the interconnection customer fund upgrades. In the case of an affected system study, for upgrades sited on the host network, the host system owner would make the final decision regarding whether to accept recommended upgrades or identify its own preferred upgrades that address those contingencies. This case-by-case rule is intended to ensure that where there is not a large difference in cost estimates, the affected system owner is permitted to ensure that its reliability concerns are addressed.

137 FERC Order No. 2023, para 1527.

In the second case, if alignment is required by FERC or a Region, then a transmission owner could be allowed to file a proposal that shows how factual or service differences require use of study criteria, models and assumptions that differ from those of the Region where it is a member and that may differ from host systems in affected system studies. Requiring transmission owners to justify such differences would also address the concern, noted in the i2X Report, that "[t]he assumptions used in interconnection studies, such as re-dispatch assumptions, are often not well-documented either in transmission provider tariffs and business practice manuals or in the interconnection facilities' study reports provided to interconnection customers."[138]

To receive approval for such a proposal, a transmission owner should demonstrate that its proposal would provide meaningful service protections, such as avoiding substantial decreases in system reliability or substantial increases in redispatch or curtailment of existing resources.[139] As an example of a modeling practice that would trigger a proposal to FERC, a transmission provider with a high level of renewable and storage resources might demonstrate a need to use modeling with a higher-than-usual level of temporal granularity.[140]

The recommendation to require transmission owners that wish to use differing study criteria, models and assumptions to file a proposal with FERC does not necessarily mean that the actual study criteria, models and assumptions need to be approved by FERC, particularly as the transmission owner may need to update those practices. Instead, the recommendation is that FERC accept the demonstration of the service protections that would be achieved by differing practices. Once demonstrated, the transmission owner would be authorized to continue to maintain, update and apply its own business practices, consistent with the characteristics of its region.[141]

### REFORM 3D. Use automation to expedite interconnection studies.

Several transmission providers are at the early stages of incorporating automation into their interconnection study processes. The transmission providers are implementing automation to streamline the application process and improve efficiency in building base cases for interconnection studies where the value of automation to relieve labor constraints is most obvious. Transmission providers report that early results are promising with significant time reductions possible by automating time-intensive processes. Additional testing and reporting of results will be necessary to demonstrate the benefits of automation and identify its role for improving the interconnection study process.

Recent automation projects implemented by Regions have generated strong interest. For example, SPP began using Pearl Street's SUGAR platform to automate model building and power flow simulation in its steady-state interconnection studies. SPP's minimum viable

138 i2X Report, p. 62.

139 Furthermore, as recognized in Order No. 2023, affected systems also have the opportunity to study the impact of the interconnection customer's generating facility in the context of a transmission service request. FERC Order No. 2023, para. 1284. We have not considered whether this reform should also be extended to require alignment of study practices with transmission service request studies.

140 Other examples of different study practices may relate to different assumptions regarding planned generation and transmission, generation and energy storage dispatch, list of contingencies to study, mitigation options, and transfer distribution factors. i2X ort, p. 62.

141 Similar reasoning is applied in FERC Order No. 2023, para 463.

product is integrated with the SPP database and is able to fully automate the interconnection modeling process, reducing the length of the process from 3 months to 1 hour, and producing 62 scenario models.[142] Similarly, a third-party case study conducted in MISO territory supports the effectiveness of the technology, finding that a typically three-week process of the queue scenario model building process was reduced to thirty minutes.[143] Both SPP and MISO have found that SUGAR can produce study solutions with improved reliability metrics and complete contingency analyses when compared to their standard modeling.

Since it began using Pearl Street's software in 2022, SPP has accelerated all of its cluster studies and now anticipates completing its 2023 cluster study by fall of 2025. The first cluster study completed using Pearl Street's software took three years (including modeling efforts that were not succeeding prior to use of SUGAR) until facility studies could begin; the 2023 cluster study is expected to reach that milestone in less than one-third of the time.[144] On the other hand, MISO recently announced delays in completing its initial system impact study for its 2022 study cycle and that it plans "an expanded scope of integration of Pearl Street's software, which is expected to be completed in late February 2025."[145] MISO's delays suggest that automation can be difficult to implement.

As these efforts are still in the early stages, we did not have sufficient evidence to inform recommendations. Yet we expect an increasing body of information to emerge from case studies in the next few years that will help identify the most effective applications of automation in the interconnection process, in turn helping develop best practices. Indeed, FERC has taken note of the promise of automation, elevating this topic to a dedicated panel at its September 2024 workshop on queue reforms.

### **REFORM 3E.** Establish independent interconnection study monitors.

To understand and continue to improve the performance of transmission providers and affected systems in performing interconnection studies, FERC should require transmission providers to appoint an independent monitor to oversee interconnection studies. Even though the independent monitors would not have direct authority to revise study practices, they would have authority and unique expertise required to deeply engage in ongoing study practices, identify opportunities for alignment, and suggest other study practice improvements that could be adopted voluntarily or considered by FERC in future reform efforts.

**Study accuracy is difficult to verify by the public, states, consumer advocates, and others because of the confidential nature of transmission data.**

142 SPP, AWS, Pearl Street Technologies, and NextEra, *Interconnection Study Automation* (November 6, 2023), presentation to FERC staff; and AWS, untitled presentation (April 16, 2024).

143 Miller Tahne and Vejzovic Omer, *Power Flow Model Building with SUGAR: A MISO Case Study* (March 17, 2022), Ulteig, p. 1.

144 SPP, *SPP Generation Interconnection Queue Study Schedule* (July 17, 2024).

145 MISO, *Updated Status Regarding DPP-2023 DPP 1 Start Date, email to Planning SuperList (August 13, 2024).*

Our recommendation is motivated by the frequent disputes regarding the timing and accuracy of interconnection studies. Particularly where participant funding is used for network upgrade costs, transmission providers may have an incentive to assign excessive network upgrades to interconnection customers and thus provide system benefits to its transmission customers at reduced cost. Study accuracy is difficult to verify by the public, states, consumer advocates, and others because of the confidential nature of transmission data.[146] At times, disputes are brought to FERC, but the Commission's limited resources and expertise may result in unsatisfying results. Moreover, the cost of a FERC proceeding is often prohibitive for project developers.

To ensure more timely processing of interconnection requests, Order No. 2023 established penalties and accountability mechanisms on transmission owners.[147] The penalties are intended to improve the policies, practices, and resource allocations of transmission owners to help ensure accuracy in network upgrade costs, flexibility, and reliability.[148] The order also directed transmission organizations and providers to consider alternative transmission technologies and complete affected system studies in a timely and consistent manner, which interconnection customers have reported as widespread and serious problems.[149] These directives should address concerns about timeliness of studies and consideration of alternative transmission technologies, but there will likely remain disputes over the accuracy and findings of interconnection studies, and potentially the timeliness of affected system studies.

FERC is reasonably hesitant to prescribe specific standards to resolve many of the issues with interconnection studies. Instead of further requirements or standards, we recommend the use of independent monitors that would bring expertise and objectivity to assess the effect of the flexibility and discretion that transmission providers exercise in conducting interconnection studies and related tasks. The transparency that independent monitors' reports should provide could inform improvements by the transmission providers or even identify targeted areas for future FERC regulatory action.

### *3E.1. Independent interconnection studies monitor proposal*

To verify improvements anticipated as a result of the reforms contained in Order No. 2023, FERC should revise its *pro forma Open Access Transmission Tariff to require transmission planning authorities and transmission providers to select and fund independent monitors.* Such independent monitors could, among other responsibilities, review study assumptions and methods with interconnection studies, and review associated study processes and staffing. The monitor could review transmission providers' practices in identifying needs and selecting facilities to resolve the criteria violations, including an assessment of whether grid-enhancing technologies, high-performance conductors or other options would be used to improve cost-effectiveness.

146 FERC has determined that operating guides used by transmission providers to address known and recurring reliability issues associated with manual commitments and curtailments are confidential. FERC, *Order Denying Complaint and Petition, Tenaska Clear Creek Wind, LLC v SPP et al.* (December 15, 2022), Docket EL22-59.

147 FERC Order No. 2023, Para 965.

148 FERC Order No. 2023, Para 1007.

149 FERC Order No. 2023, paras 1032, and 1578; Interconnection Scorecard, p. 53, 54.

Furthermore, FERC should direct such independent monitors to report annually on the performance of transmission studies conducted by transmission owners and operators, including interconnection studies but also broadly on the underlying transmission planning that will create system capability for future resource interconnections. The monitor's annual report should further highlight any potential system, regulatory, and operational barriers to utilizing the existing transmission grid (including interties) fully and efficiently, as identified by the independent monitor in the course of exercising its responsibilities, along with recommended solutions to reduce or overcome identified barriers.[150] To perform these functions, independent monitors would need FERC-sanctioned access to information currently contained only within transmission owners and transmission providers.

Finally, FERC should authorize the monitors to, on request, provide reports to state commissions and energy offices with jurisdiction over the relevant transmission owners and operators on topics closely related to the scope of duties authorized by FERC.

### *3E.2. Responsibility to file independent interconnection studies monitor proposal*

To address the diversity of circumstances, quantity and scale of projects, and other relevant differences among the transmission owners and operators, a one-size-fits-all approach is impractical. FERC, Regions, and transmission providers should pursue either:

a) A single independent interconnection studies monitor to cover the Region and all of its member transmission owners; or

b) An independent interconnection studies monitor for the Region and separate responsibility for each transmission owner in the Region to propose its own independent interconnection studies monitor.

Transmission owners who are members of a Region who select option (b) above as well as those that are not members of a Region should file a proposal for an independent interconnection studies monitor.

For those transmission owners with responsibility for developing an independent monitor proposal, FERC should encourage transmission owners to act in coordination. Transmission owners should be encouraged to rely on regional independent interconnection study monitors that would provide for consistency and rapid adoption of lessons learned from monitoring activities. Such regional monitors could be established under the many different types of regional organizations that coordinate the activities of transmission owners, such as the Carolinas Transmission Planning Collaborative, the Georgia Transmission Corporation, the Florida Reliability Coordinating Council, the Pacific Northwest Utilities Conference Committee and WestConnect.

Each proposal should identify the monitor, provide evidence for the monitor's independence; describe procedures for ensuring stakeholder engagement and continuing independence

150 However, the scope of the monitors should not extend to conducting comprehensive alternative studies. Rather, the identification of barriers and recommended solutions should be focused on shortcomings in executing best practices. In other words, FERC should not duplicate the planning or engineering functions of the transmission planning authorities or transmission providers.

of the monitor; and define the monitor's scope of review and budget (to be funded through transmission rates). With respect to the scope, FERC should provide direction to the transmission owners and operators. However, FERC should also direct that systems that encompass larger or more complex study portfolios should propose a more expansive scope of review than would be appropriate for systems with fewer or simpler projects in the existing transmission study queue. For example, transmission owners with responsibility for only facility studies might not require as intensive monitoring as a transmission operator that proposes to cover all regional interconnection studies.

### *3E.3. Scope of assessments conducted by Independent Interconnection Studies monitor*

The scope of responsibilities for the independent monitor should focus on information that goes beyond the specific metrics and accountability required in FERC Orders No. 2023 or No. 1920. Those orders included a number of findings in which FERC allowed flexibility, allowed discretion, did not establish specific consequences for noncompliance with a required action, or declined to act based on either an insufficient record or a proposal being out of scope.

To be clear, our recommendation is that the independent monitor should be focused on transparency, bringing attention to important trends and providing an informed opinion on systemic problems, but not engaging on a project-specific basis. There are a wide range of topics on which monitors could gather and assess information, including:

- Effectiveness of site control requirements and commercial readiness deposits in disincentivizing interconnection requests that do not appear to be commercially ready;[151]
- Reasonableness of transmission providers' acreage requirements for generating facilities in implementing site control requirements;[152]
- Reasonableness of transmission providers' consideration of regulatory limitations in implementing site control requirements;[153]
- Whether scoping meetings for cluster studies are addressing interconnection customers' questions in a reasonable and timely manner, including addressing issues that require consideration of commercially sensitive information;[154]
- Reasonableness of operating assumptions, such as those used for electric storage resources, in interconnection studies;[155]
- Overall effectiveness of interconnection study evaluation processes, standards and selection criteria affecting the identification and evaluation of transmission facilities, including alternative transmission technologies;[156]
- Reasonableness of decisions to require restudies due to withdrawals or modifications of interconnection requests;[157]

151 FERC Order No. 2023, paras. 594, 604, 690.
152 FERC Order No. 2023, paras. 595, 602.
153 FERC Order No. 2023, paras. 607-611.
154 FERC Order No. 2023, paras. 246-247.
155 FERC Order No. 2023, paras. 1528-1529, 1531.
156 FERC Order No. 2023, paras. 1587, 1589.
157 FERC Order No. 2023, paras. 335, 374.

- Timeliness and reasonableness of material modification and surplus service evaluations by transmission providers;[158]
- Whether affected system study methods are adequately identifying all potential impacts,[159] such as those due to inadequate coordination between transmission providers;[160]
- Whether affected system studies are causing interconnection agreements to be delayed or filed as unexecuted;[161]
- Conditions under which affected system studies cause substantial increases in network upgrade costs;[162]
- Accuracy of study cost estimates relative to final costs, including whether cost estimates improve as requests progress through the interconnection study process;[163]
- Reasonableness of how interconnection study data are applied to the weighting or discounting of generator interconnection requests and withdrawals in the long-term regional transmission needs scenarios; and
- Other topics that FERC or stakeholders may identify.[164]

FERC should allow transmission providers (for Regions, their Boards) to propose direction or limitations to its independent monitor's scope of work, but such direction or limitations should be justified by evidence. FERC's policy regarding the independent monitor should be to provide it with discretion to prioritize topics based on its judgement, within its approved budget. FERC's evaluation of the proposals should also consider the degree to which meeting the information requirements of the independent monitor may require substantial resources, hindering the ability of transmission providers to increase the speed of interconnection queue processing.[165] To address such resource constraints, FERC could consider proposals to gradually increase the scope and resources of the independent interconnection studies monitor.

### *3E.4. Voluntary independent interconnection studies monitor alternative*

FERC can assert regulatory authority to require such an independent monitor, but the effectiveness of each monitor will depend on whether its findings and recommendations are influential with executive leadership of transmission providers, or with regulators – state or federal. While we recommend mandating independent monitors for all transmission owners and operators, FERC could also choose to provide a process by which transmission owners and operators voluntarily propose to appoint an independent interconnection studies monitor and accept petitions by parties that provide cause to question the effectiveness of a transmission owner or operator's study practices. Such a case-by-case process seems burdensome to FERC and involved parties, unnecessary in light of the evidence that study processes are problematic (in one way or another) across the vast majority of transmission owners and operators, and

158 FERC Order No. 2023, paras. 1408, 1416, 1419, 1447.
159 NRECA, *Comments* (October 13, 2022), FERC Docket RM22-14, pp. 36-39; FERC Order No. 2023, paras. 1118, 1198.
160 FERC Order No. 2023, para. 1172.
161 FERC Order No. 2023, para. 1125.
162 FERC Order No. 2023, para. 1151.
163 FERC Order No. 2023, Paras. 261, 786.
164 FERC Order No. 1920, paras. 517-518, 635, 639-642.
165 See, for example, FERC Order No. 2023, para. 1619.

needless given the recommendation that the responsible entities be provided guidance regarding flexibility in the budget for and scope of the independent monitor's duties.

### *3E.5. Precedent for independent interconnection study monitors*

There is ample precedent for requiring independent monitors to increase transparency and improve FERC's ongoing understanding of technical issues. An independent monitor focused on interconnection studies would provide ongoing information and assessments regarding the aspects of Orders No. 2023 and No. 1920 that do not have specific metrics and accountability provisions. Such a monitor would fit comfortably within Commission precedent for the use of independent monitors.

**Independent market monitors are one well-known precedent.**[166] When FERC initially approved market designs by the Regions, it required that each employ an independent market monitor who would be an expert in markets, have access to confidential market information (such as energy bids), and be able to review both market participant behavior and the efficiency of market outcomes. In 1997, FERC staff economist Dr. Bernard Tenenbaum articulated the need as, "The purpose of market surveillance is to look for things that are not working. This may happen because the sector structure is not functional, an obvious mistake was made in the rules or one or more pool participants are able to exercise market power."[167] As FERC's later policy statement explained, market monitors "monitor organized wholesale markets to identify ineffective market rules and tariff provisions, identify potential anticompetitive behavior by market participants, and provide the comprehensive market analysis critical for informed policy decision making."[168]

Similarly, in responding to issues that arise with transmission study practices, FERC may need an independent monitor's periodic reports to inform parties and the regulator's final decision on tariff revisions, guidance, or other general regulatory proceedings. As the most useful information that interconnection study monitors may develop is likely to come from the analysis of multiple projects, the monitors should not be directed to review individual projects on a routine basis.

Another precedent is the use of **independent Generation Replacement Coordinators (GRCs)**, which monitor compliance with FERC's orders on retired generator replacement in non-RTO/ISO regions, as discussed in Appendix 1.4. FERC required those monitors to address concerns of market power and discrimination by integrated utilities that own both transmission and most of the existing generation interconnected to their systems.

The responsibilities of the coordinator, as spelled out in Xcel Colorado's agreement with its consultant, include ten specific areas of responsibility. The GRCs must meet a number

166 For discussion, see: FERC, *Order No. 719: Wholesale Competition in Regions with Organized Electric Markets* (October 17, 2008), Docket RM07-19. Henceforth, "FERC Order No. 719." Also note that independent market monitors have been used in other markets. See, for example, the Independent Auction Monitor for Southern Companies' Day-Ahead and Hour-Ahead Energy Auctions. Brattle Group, *Fourteenth Annual Informational Report of the Independent Auction Monitor*, Docket ER09-88 and ER17-514.

167 James Barker, Jr., Bernard Tenenbaum, and Fiona Wolf, *Governance and Regulation of Power Pools and System Operators: An International Comparison*, 382 World Bank Technical Papers 25 (1997), p. 37.

168 FERC, *Market Monitoring Units in Regional Transmission Organizations and Independent System Operators*, PL05-1, (2005) at Appendix A. The Commission later stated that the functions should include, "evaluating existing and proposed market rules, tariff provisions and market design elements, and recommending proposed rule and tariff changes." FERC Order No. 719, par 354.

of neutrality and independence standards, such as demonstrating independence from interconnection customers, the transmission provider, or connected facilities.[169] In addition to a number of data collection and evaluation responsibilities, the GRC provides some monitor-like functions such as, "Independently review and validate the data, information, and analyses provided by Transmission Provider to GRC in connection with Generator Replacement process.[170]

Three further examples of independent monitors that may be of precedential relevance are:

- **Duke Energy Merger Monitor:** In its approval of the merger between Duke Energy and Progress Energy, FERC's order included an independent monitor. The independent monitor's responsibilities included monitoring certain power sales agreements and, if required by FERC, compliance with transmission set-aside requirements. FERC also required the independent monitor to provide quarterly status reports on the construction of several transmission expansion projects included in the decision as a condition of approving the merger.[171] The monitor tracked project construction, which was completed early without apparent incident[172] and verified compliance with operating requirements through at least 2023.[173]
- **Monitoring Activities of Independent Coordinators of Transmission:** In at least two orders approving the creation of an independent coordinator of transmission, FERC has also included monitoring responsibilities. For Entergy, FERC directed the independent coordinator to lead a stakeholder process to resolve complaints about repeated denials of transmission requests.[174] For MidAmerican, FERC directed the independent coordinator to report on whether MidAmerican provided transmission services to its wholesale affiliate that were not available to non-affiliates, among other prohibited actions.[175] Only one report by any of the two independent coordinators was located, and it did not discuss the independent coordinator's monitoring responsibilities.[176]
- **Duke Energy Independent Monitor:** In FERC's order approving Duke's selection of MISO as its independent transmission coordinator, it also approved the use of an independent monitor to review Duke's operation of its transmission network and investigate potentially anticompetitive behavior.[177] Potomac Economics' quarterly reports included detailed market screen analyses. Duke terminated its voluntary independent monitor at the end of 2018.[178]

In general, FERC supported the use of monitors using their authority to ensure that transmission service would be provided in a nondiscriminatory manner. For example, in its determination

169 Excel Colorado. *Generation Replacement Coordination Agreement, ER21-2356,* (July 28, 2021), p. 4.

170 *Id.*

171 FERC, *Order Accepting Revised Compliance Filing, As Modified, and Power Sales Agreements* (June 8, 2012), Docket EC11-60-004 and others.

172 Potomac Economics, *Independent Monitoring Report on Permanent Mitigation Measures for Duke Energy Corporation and Progress Energy Inc.: Final Report on Transmission Expansion Projects* (May 2014), FERC Docket EC11-60.

173 Potomac Economics, *Seasonal Independent Monitoring Report on "Stub Mitigation" Transmission Set Aside for Duke Energy Corporation and Progress Energy Inc.: Summer Season 2023* (September 2023), FERC Docket EC11-60. Hereafter, "Potomac Stub Mitigation Report."

174 FERC, *Order on Rehearing* (September 22, 2006), Docket ER05-1065-001, para. 22.

175 FERC, *Order Conditionally Accepting Tariff Revisions* (December 16, 2005), Docket ER05-1235, para. 27.

176 TranServ International, *TSC Semi-Annual Report on MidAmerican Energy Transmission Stakeholder Action Items for Reporting Period March 01, 2007 - August 31, 2007 In Response to FERC Order within ER06-847-002 and ER05-1235-003* (January 29, 2008).

177 FERC, *Order Accepting Independent Entity and Transmission Monitoring Plan* (December 19, 2005), Docket ER05-1236.

178 Duke Energy, *Notice of Termination of Transmission Service Monitoring Plan* (December 31, 2018), Docket ER05-1236.

that Entergy's independent coordinator of transmission should have monitoring responsibilities, it sought to address concerns about the transparency of Entergy's monitor that "could allow Entergy to discriminate in favor of its generators when assigning transmission service."[179]

FERC also rejected concerns about jurisdictional shifts between state or other retail utility regulators and the Commission. In responding to concerns about Entergy's independent coordinator of transmission, FERC pointed out that it was not authorizing the transfer of operational control, responsibility for filing the OATT, or other transmission provider responsibilities to the independent coordinator.[180]

179 Potomac Stub Mitigation Report.
180 FERC, *Order Conditionally Approving Independent Coordinator of Transmission Filing,* (April 24, 2006), Docket ER05-1065, para. 116.

REFORM 4

# CONSTRUCTION

*Speed up the transmission construction backlog.*

Completion of the interconnection process occurs with commercial operation — the new generation facility begins delivery of power to the grid. Over the past few years, there has been increasing attention to the problem of delays *after* the interconnection agreement has been signed. According to one survey of project developers, the construction period is the cause of nearly half of project delays, at a cost of around $200 per kW.[181] Observers have pointed to many factors that may be contributing to such delays. Among those factors are supply chain bottlenecks, prioritization/project management by transmission owners, and voluntary delays by interconnection customers who may lack contracts with power customers, necessary permits, or face construction delays of their own.

**Today, however, the same logjam that affects the interconnection queue similarly impacts the construction queue.**

Perhaps a decade ago, the timeliness of the construction phase was less problematic, as self-motivated project developers worked with utilities that had a vested interest in getting capital deployed to the transmission system. Today, however, the same logjam that affects the interconnection queue similarly impacts the construction queue. In addition to the large number of generation projects challenging transmission owners' capability to manage resources and resolve scheduling conflicts, an added challenge is burgeoning *load interconnection* that is stressing transmission owners' capacity and increasing pressure on supply chains for critical interconnection equipment. To address the untimely and, consequently, costly construction backlog, we recommend greater transparency regarding the construction phase and a strategy to address supply chain bottlenecks.

First, FERC should require transmission owners to file a transmission project construction report and require FERC-jurisdictional transmission owners to establish a stakeholder process

181 Robi Nilson, Ben Hoen and Joe Rand, *Survey of Utility-Scale Wind and Solar Developers Report* (January 2024), Lawrence Berkeley National Laboratory, pp. 51, 53.

for the review of that report. Section 4-A.2 describes the design objectives for the report, but FERC should solicit further information from transmission providers and stakeholders before proposing to require a report. In the meantime, FERC could issue a data request to identify reasons for construction delays.

Second, we recommend that the utility industry and government partner to place advance orders for large power transformers to reduce supply chain bottlenecks.[182] Supply chain bottlenecks are widely understood to be causing longer construction schedules for generation interconnection projects. A collaborative procurement effort targeted at key equipment required for network upgrades could enhance the confidence of manufacturers in future demand. Collective efforts are needed because the cost and physical characteristics of large power transformers present challenges to stockpiling by individual transmission owners. However, for collective efforts to succeed, it may be necessary for a federal government agency to provide the capital or financial guarantee necessary to establish a collective upgrade purchase program.

### *Background: Understanding Longer Construction Timelines and Delays*

In a recent opinion essay, former FERC Chairman Richard Glick and GridStor CEO Chris Taylor wrote,

> It is imperative that transmission owners supply the resources and personnel needed to keep pace with California's clean energy transition and enable new clean energy projects to connect to the grid faster. Transmission owners who invest in staffing up should be financially rewarded based on achieving certain timeline metrics.
>
> … CAISO can similarly start a new track in its current reform initiative focused on accelerating connections of clean electric generation and storage projects to the larger state grid, along with stronger monitoring of transmission owner performance. It can take too long to buy key components to upgrade a grid. Today, a utility might have to wait three years to get electric transformers that are required to connect new projects. Waiting until the last minute to procure these transformers is now commonplace. Reforms are needed to allow utilities to make these investments faster so as not to jeopardize California's wind, solar and storage projects.[183]

Improving transmission construction is challenging. Reforms can't simply involve hiring outside companies or implementing automation because the projects need to be closely managed with attention to reliability and compatibility with legacy equipment. FERC, the Regions, and state regulators who wish to accelerate construction will need to begin with an understanding of specific challenges within transmission owners' existing reliability-focused management strategies and complete pilot testing to ensure reliability is maintained or enhanced.

---

182 It should be noted that this report focuses on actions that can be taken by utilities and regulators to address immediate bottlenecks. Other actions to resolve challenges in the supply chain, such as addressing workforce limitations through training programs, are the subject of reports by other parties. See for example: National Infrastructure Advisory Council, *Addressing the Critical Shortage of Power Transformers to Ensure Reliability of the US Grid* (June 2024 draft/pre-decisional). Hereafter, "NIAC Report."

183 Richard Glick and Chris Taylor, *California is Updating its Electric Grid Too Slowly to Meet Climate Goals*, Sacramento Bee (December 11, 2023).

Various stakeholders assert a range of underlying causes of longer construction timelines.[184] For example, while the Glick and Taylor essay quoted above correctly points out that utilities often have to wait three years to procure electric transformers (delays may have crept up to five years or longer for some transformers), some developers and utilities initiate procurement of critical equipment even before projects are approved.

Similarly, Southern California Edison (SCE) claims that project delays are "typically project-specific and often due to external concerns, such as material delays, licensing/permitting delays, or [interconnection customer] delays."[185] SCE's claim is similar to those made by other utilities and experts associated with transmission owners and operators. But SCE's claim is not backed up by data reported by SCE or Pacific Gas & Electric (PG&E). Instead, both utilities' data demonstrate that execution-related issues and budget constraints are the most frequent and severe causes of delays to project in-service dates. For example, PG&E's projected in-service dates for upgrades to support more generation capacity are most often delayed due to corporate capital constraints, resulting in prioritization of safety projects (e.g., wildfire risk mitigation) over interconnection of new generators.

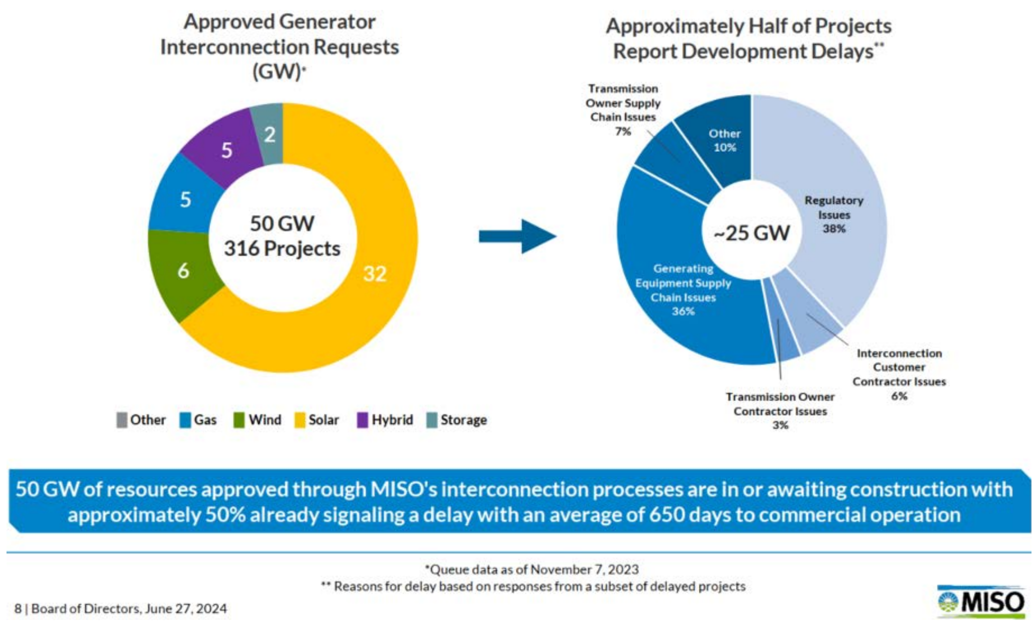
184 It is worth noting that both the data and the interests of experts consulted for this report agree that longer construction timelines and delays are a more important concern than high costs and cost escalation. There are specific projects where developers have experienced unexpected and severe cost overruns, and because network upgrade costs generally remain a relatively small part of the cost of bringing new generation online, once a project enters the construction phase, cost escalation is unwelcome but *usually* not a threat to project completion.

185 SCE, *Response to Large Scale Solar Association* (January 25, 2023), CAISO Transmission Development Forum Stakeholder Comments, p. 12. Henceforth, "SCE LSSA Response."

While interconnection customers acknowledged that the external factors highlighted by transmission owners and operators did occur, they were most frustrated with factors that are within the control of transmission owners, such as project management or financial prioritization. And the data — such as it exists — is so poor that there can be no convincing ranking of problems, especially outside of California.

Most recently, MISO reported regulatory issues and supply chain issues as responsible for the vast majority of development delays.

**FIGURE 2** | MISO Construction Delays Constrain 2023 Capacity Additions to 5.6 GW *(nameplate)*[186]

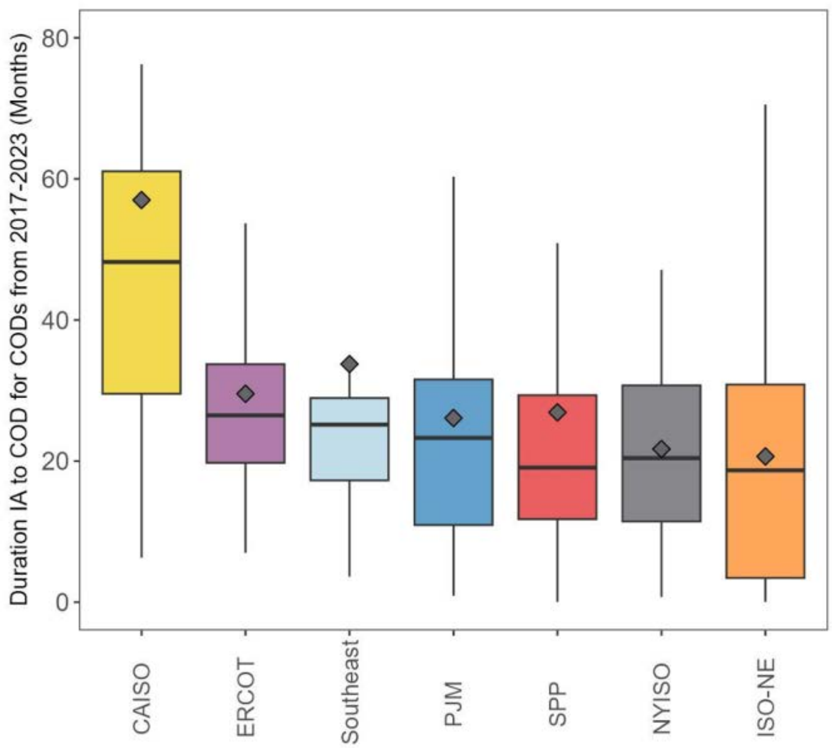



Nowhere in the country does there appear to be a transmission owner or operator that maintains a centralized tracking and reporting system for generation interconnection and transmission system upgrade projects, including reasons for delays or cost increases. Nonetheless, the data that are available and analyzed in Appendix 3 provide some clues as to the relevant factors affecting construction timelines and delays.

For example, as discussed in the Interconnection Scorecard report, interconnection requests in ERCOT can reach commercial operation much quicker than in other parts of the country, mainly because ERCOT's rules limit the scope of studies to limited network upgrades. This allows projects to be placed in service with minimal upgrades — but at risk of curtailment during conditions of grid congestion.[187] Even so, among regions that provide data, ERCOT's construction durations — the time between the execution of an interconnection agreement and the commercial operation date of a new generator — are fairly typical, as shown in Figure 3.

186 MISO Board of Directors, Strategy Update: Reliability Imperative (June 27, 2024), pp. 7-8.
187 Interconnection Scorecard, pp. 54, 61.

**FIGURE 3** | Berkeley Lab Analysis of Construction Timelines[188]




One might expect that ERCOT's transmission owners would complete interconnection-related construction quickly. After all, ERCOT does not require extensive transmission system upgrades prior to generation projects achieving commercial operation. The indication that ERCOT transmission owners are not completing such projects quickly — as well as review of other data from several Regions in Appendix 3 — suggests that complexity of transmission system upgrades is not a key driver of longer construction timelines and delays.[189]

The two most important findings from the data in Appendix 3 are:

1. Procurement lead time and construction timelines are increasing across the industry, and
2. Some transmission owners complete upgrade projects more quickly and with fewer delayed projects (or shorter delays) than other transmission owners.

While there is convincing evidence that supply chain constraints affecting key equipment for transmission upgrades are a key driver in the longer construction timelines, as discussed further below, other causes for the consistent increase in construction timelines are less well understood. Even less information can be obtained about the reasons for variation in schedule

188 Queued Up 2024, p. 40. The report notes that, "Data were only available for 836 projects across 5 ISO/RTSs and one utility (Southern Company), out of 4,155 total "operational" project in the full dataset." Some data are not publicly available or require review of individual project reports.

189 An exception is that some of the data reviewed in Appendix 3 suggest that the very largest transmission upgrade projects are trending towards much longer timelines and experiencing larger delays. These projects are more typically associated with system reliability requirements rather than generation interconnection projects.

performance among the many transmission owners. This creates an imperative for improved transparency through reporting and further investigation into the causes of construction delays. Relying on such information will enable FERC, the Regions, transmission owners or utility regulators to take further action, such as some of the steps outlined Appendix 4.

### **REFORM 4A.** Improve reporting on the transmission project construction phase.

FERC is in a unique position to require comprehensive and uniform nationwide reporting on the transmission project construction process. As recommended in the i2X Report, there is a need to "improve the scope, accessibility, quality, and standardization of data on projects already in interconnection queues, including project attributes [and] cost estimates," both during the interconnection study process as well as during the construction process.[190]

**very few transmission owners or regulators have publicly available reporting systems for transmission projects, and what does exist is very limited**

Most regulators — and likely many transmission operators themselves — lack a comprehensive understanding of the actual causes of transmission project delays. While better information itself will not cause reforms, those utilities and regulators who are motivated to identify and implement other reforms will be better equipped to do so with better information.[191]

#### *4A.1. Applicability of Existing Models to Recommended Project Construction Reporting*

As reviewed above, very few transmission owners or regulators have publicly available reporting systems for transmission projects, and what does exist is very limited. California has the strongest model for tracking transmission upgrade projects, with a comprehensive list of transmission upgrade projects and information on schedule, budget, and reasons for delays. California has recently established a new Transmission Project Review Process, as summarized in Appendix 2.2. However, even California's new requirements could be improved – for example, the database does not cross-reference transmission upgrade projects to the generation interconnection projects that depend on their completion.

Elsewhere, transmission project or generation interconnection project data published by ISO-NE, MISO, PJM, and SPP include useful information and have some unique attributes, but none of these represent a model for national adoption.[192] For example, the most informative database on generation interconnection projects may be PJM's, but that database cannot be linked to PJM's transmission network upgrade project tracking system and neither provides reasons for delays nor project changes.

The weaknesses in reporting may be due to the wide diversity of projects included in the transmission upgrade portfolio, such as emergency repairs, load-driven reliability upgrades,

190 i2X Report, Solution 1.1, p. 14.

191 See, for example, i2X Report, pp. 14-15.

192 The best available data on New York's transmission projects appears to be a New York Power Authority summary of its existing plan's projects, including the current status of the project and proposed in-service date.

generation interconnection projects, and major new transmission lines. For projects with different drivers, there are significant differences in the definition of when projects are approved and when the development/construction timeline should start.

Another challenge to existing reporting systems is the variation in project cost responsibility. In some cases, the costs may be reviewed in state regulatory proceedings. For network upgrades related to generation interconnection projects, the interconnection customers may be responsible for the costs, depending on the transmission system's cost allocation rules. And still other transmission project costs may be self-approved by the utility, followed by FERC's ratemaking process which presumes those costs to be prudent unless challenged by an intervening party.

### *4A.2. Design Objectives for a Transmission Project Construction Report and Stakeholder Process*

Making better information visible — to regulators, affected stakeholders, the public, and even to senior management of transmission system owners — will not be simple. A single reporting template that recognizes the wide variation in schedule structures and cost responsibilities will, by necessity, be complex. Yet such information could (and should) empower its users to identify the causes of transmission project delays and cost overruns. If acted upon, such information could help reduce the time and cost of building the necessary transmission upgrades.

In Appendix 3, a review of much of the available post-interconnection data from across the country is provided. An ideal data record would enable analysis of the following key factors:

- Generation projects, including the date on which an interconnection agreement is signed and the projected cost of completing necessary network upgrades.
- All types of transmission network upgrade projects, including the date on which the project is approved for construction, the projected cost and completion date, and the actual cost and completion date.
- A clear linkage between the generation projects and network upgrade projects necessary for full commercial operation.
- Identification of any changes in scope (including cost and schedule changes), such as additional network upgrade projects assigned to generation projects due to a post-generation interconnection agreement restudy or affected system study.
- The reason for delays or cost increases of either the generation projects or the network upgrade projects.
- Basic information about the nature of the generation projects (e.g., fuel type, capacity, interconnection service type) and network upgrade, including the type of network upgrade (e.g., substation, line reconductoring) and construction responsibility (usually the transmission owner, but could be another party).

FERC should revise its pro forma Open Access Transmission Tariff to require a minimum annual filing from each transmission owner that conducts facility studies or constructs network upgrades in response to interconnection requests,[193] with a scope that includes all transmission projects including those related to:

- Interconnection requests (governed by Order No. 2023),
- Short-term reliability and economic needs (governed by Order No. 1000),
- Long-term regional transmission needs (governed by Order No. 1920), and
- Other projects (including those self-approved by a transmission owner) whose costs may be included in any rates that FERC reviews under its Federal Power Act authority.[194]

FERC should also direct each of those transmission owners under its Federal Power Act jurisdiction (and encourage non-jurisdictional utilities) to create a stakeholder process that meets the following standards:

- Participation by stakeholders, including market participants, any state energy regulatory agency (e.g., a state energy office), actual/potential interconnection customers, consumer/environmental interest organizations, and consultants to any stakeholder.[195]
- Quarterly meetings and report updates during the first two years, which may be reduced to two meetings and report updates per year after that date.[196] Utilities with a reasonably equivalent reporting and stakeholder process mandated by a state regulator are not expected to begin with more than two meetings.
- A post-meeting comment and response process that provides stakeholders with a written response to questions, an opportunity to address possible omissions from the report, and documentation of information presented during the meeting.[197]

It appears that there is no transmission owner or operator that maintains a complete data set such as that outlined above. Many transmission owners or operators maintain separate lists of generation projects and network upgrade projects. Rarely are they linked together and rarely are reasons for delays or cost increases collected into such databases.

The recommended reporting could encompass over a hundred entities. While FERC should recognize the scale of such reporting in its design process, it should not hesitate to apply the requirement in a broad manner. The responsibilities to build transmission upgrades and interconnect new generation resources are widely dispersed, and if FERC is to develop an accurate understanding of the construction phase, it needs data from all responsible entities.

FERC should look to the new tracking system mandated by the California Public Utilities Commission as the basis for a national model, because it is the most mature, having evolved

193 See, for example, the information filing requirement in Order No. 890 creating the requirements in 18 CFR § 37.6(h)-(i).

194 The scope should be the same for all transmission owners, even those that are jurisdictionally-exempt from FERC rate review, under the reciprocity provision of Order No. 888. Requiring the submission of cost information from jurisdictionally-exempt transmission owners would not expand FERC's authority to, in particular, allow or disallow recovery of costs by jurisdictionally-exempt transmission owners. For example, the requirement to provide information about the reasons for delays or cost increases does not require a transmission owner to opine on prudence. The proposed information requirement would require transmission owners to categorize and generally characterize an event that precipitates a decision to delay or increase the cost estimate of a project.

195 CPUC, *Resolution E-5252*, (May 2, 2023), p. 14. Henceforth, "CPUC E-5252."

196 This standard is based on review of California's transmission owner stakeholder process. Based on information from the early meetings, it appears that frequent meetings were useful at clarifying and improving the reporting process. As the process matured, it appeared that less frequent meetings and reports provided sufficient information for monitoring and addressing identified issues.

197 This standard is based on review of California's transmission owner stakeholder process. The written record provided essential context for this report as well as evidence of meaningful responses to stakeholder feedback.

through several iterations over the past decade. California regulators have been motivated to improve construction project reporting because:

- Stakeholders are frustrated with the exceptionally long 58-month construction timelines for generation interconnection projects (indicated by the grey diamond in Figure 3), and
- CAISO and California's utility regulator face near-term policy and reliability imperatives to bring large amounts of new generation online, motivating them to increase the pace of clean energy deployment.

Of particular importance is that California's required reports are unique in including the transmission owner's identified causes of delay to network upgrade construction schedules or changes in cost.[198]

The design of the construction project reporting system will, by necessity, require a substantial amount of information. For example, prior to the adoption of a new system, California's transmission owner reports included over 60 data fields[199] – and its new system does not include all the information we recommend be collected (e.g., Section III as shown in Figure 4). On the other hand, there are opportunities to simplify reporting and interpretation of the reports, including standardization of terms and milestones, as discussed in Section 4-A.4.

### *4A.3. Transmission Project Reporting Design*

Based on the review of existing transmission project reporting systems in Appendix 3), FERC should circulate a conceptual design for a transmission project construction report to transmission owners and other stakeholders for further input. A recommended conceptual design is provided in Figure 4. When circulating this conceptual design for input, FERC should also request specific information from transmission owners, as discussed in Section 4-A.5, in order to better standardize key information in a construction project reporting system.

198 Many transmission providers publish completed interconnection studies (or agreements), which include interconnection cost and schedule data. i2X Report, p. 15. For example, MISO's website has some information about delays affecting individual projects, but this information is made available in individual project documents (pdf format) and attempts to obtain the raw data in database format were unsuccessful.

199 CPUC E-5252, p. 6.

**FIGURE 4** | Conceptual Design for a Transmission Project Construction Report

**I. Transmission Construction Project**

A. Project Name

B. Project Identification Number

C. Project Purpose/Classification

D. Project Benefits: Select from standardized list of benefits, multiple selections allowed, provide opportunity for narrative details

E. Construction Period Start Date

F. Basis for Construction Period Start Date: Select from standardized list of start date types, including (i) date of Interconnection Agreement Execution, (ii) approval of project by relevant decisionmaker, and (iii) others as identified by FERC

**II. Network Upgrade Facilities Included in Project**

A. Facility Name

B. Facility Upgrade Identification Number

C. Type: Select from standardized list of facility types (e.g., reconductoring), provide opportunity for narrative details

D. Original Planned Cost

E. Current Planed Cost

F. Actual Cost (when known)

G. Cost details (narrative)

H. Original Planned In-Service Date

I. Current Planned In-Service Date

J. Actual In-Service Date (when known)

K. Schedule factors: Factors that are causing the schedule to be longer than would reflect good utility practice in the absence of factor

1. Category of factor
2. Description of factor
3. Estimated contribution to greater length of project schedule (months)

**III. Related Interconnection Requests (if any)**

A. Interconnection Request Name

B. Interconnection Request Project Number

C. Owner/Developer

D. Substation

E. Service Type: Select from standardized list, including ERIS, NRIS, and new load

F. Size: Capacity Delivered or Required

G. Dispatch: Technical potential for upward/downward dispatch/load management

H. Project Type:

1. Generation: Fuel/technology
2. Load: Classify by load shape and dispatchability

**IV. Record of Updates**

A. Report element (e.g., Current Planned In-Service Date)

B. Date of update

C. Update (e.g. June 2026)

D. Impact of update (e.g., months of delay)

E. Reason for the update, selected from a standardized list of reasons, provide opportunity for narrative details

### *4A.4. Information Required for FERC to Standardize Reporting*

In addition to soliciting input on the conceptual design for a transmission project construction report, FERC should specifically request information on how to define the response options in a consistent and well-understood manner. It is particularly important that FERC survey transmission owners, transmission operators, and state regulators, each of whom will be a primary partner in supplying and consuming information in the report.

Despite the progress in California, standardization remains a challenge. California's reports include wide variation in language used to describe the project purpose, key equipment, and the causes of updates to cost or schedule. Because of this variation, the analysis of PG&E and SCE's data in Appendix 3.1 required a degree of interpretation. For example, many of the projects with identified causes of delay mentioned more than one cause or included causes that were subject to interpretation.

Furthermore, across all the datasets in Appendix 3, there is a lack of consistency in key reporting requirements. For example, while the concepts of in-service and commercial operation dates are well-understood and appear to be used consistently across all data sources, information in the reports that is related to the beginning of the construction process is not defined consistently from region to region. In some cases (e.g., PJM's transmission upgrade project database), there is no useful information that identifies the date at which the construction process began and it is thus impossible to obtain construction duration information. Elsewhere, the lack of clarity and consistency in reporting the beginning of the construction process makes it difficult to compare construction duration between transmission owners, and even between different types of projects in the same report.

As an example of how FERC might apply the findings from such a survey to better define the causes of project schedule change, FERC could structure the reporting such that transmission owners would identify the cause(s) as falling within several specific, well-defined categories. The report would also provide an additional field for narrative details. Each cause should also be linked to an estimate of the resulting schedule change (in months). A hypothetical report might include the information shown in Table 3 for a schedule change to a transmission upgrade project.

**TABLE 3** | Hypothetical Project Schedule Change Data

| Date of Change | Cause (pick list) | Cause Details (narrative) | Months of delay |
|---|---|---|---|
| **6/1/2025** | Supply chain | Transformer delivery delayed | 2 |
| **6/1/2025** | Permitting | Zoning hearing delayed | 3 |

For the hypothetical data shown in Table 3, this entry would be linked to an update to the transmission project's projected in-service date. In this case, the delay would likely be 3 months (since the two causes of delay are unrelated and thus the maximum delay drives the change to the in-service date). This entry would also be linked to updates to related generation interconnection projects if the network upgrade represents a critical schedule constraint to the project.

This example is intended to generally illustrate the types of issues that FERC should resolve in designing the reporting requirement. In addition to a survey of transmission owners, it would be useful for FERC to encourage or itself convene workshops with management from transmission owners and operators who can provide insights that would be relevant for designing a practical and useful reporting requirement.

### *4A.5. An interim FERC data request to identify reasons for construction delays*

In the near-term, to fill the information void about reasons for delays, FERC could issue data requests to transmission owners to solicit information on the source of delays. FERC has issued data requests in other instances to ensure that rates are just and reasonable or transmission service is non-discriminatory.[200] The information could be provided confidentially to the extent necessary. One potential issue is that the Paperwork Reduction Act would require additional approvals. We have not specifically studied the impact of this process on such a request, but it could be made on a comprehensive, yet voluntary basis. FERC could give greater weight to the opinions of respondents who provide comprehensive responses as compared to those who may refuse to respond, suggesting that their opinions are less informed by facts.

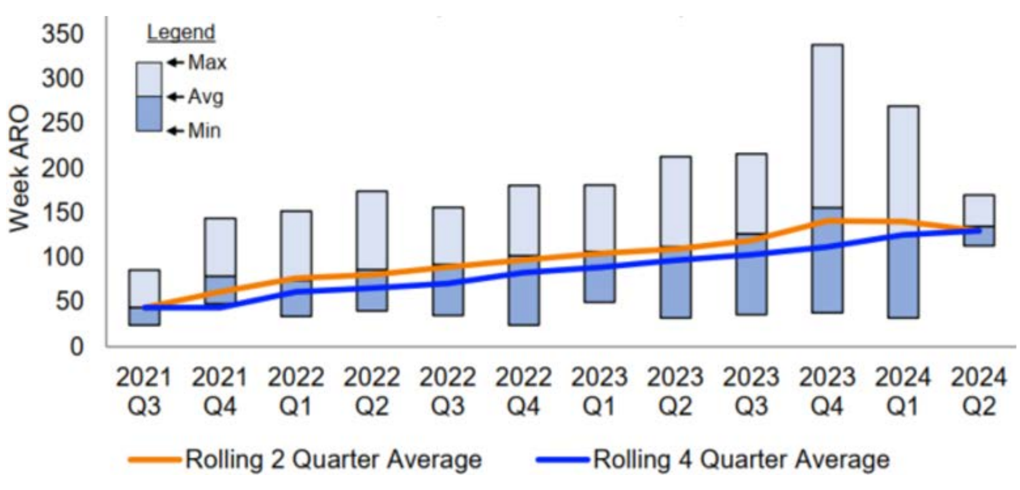
### REFORM 4B. Industry and government collaboration to reduce supply chain bottlenecks.

Supply chain bottlenecks are widely understood to be causing longer construction schedules for generation interconnection projects. NERC recently recognized,

> Lead times for transformers, circuit breakers, transmission cables, switchgears, and insulators have increased significantly since 2020 … affect[ing] new project construction, existing asset upgrades, pre-seasonal maintenance, and the interconnection of new resources and customers.[201]

For example, in October 2023, Pacific Gas & Electric (PG&E) stated that the utility industry is "seeing unprecedented lead times from suppliers that manufacture our 115kV, 230kV, and 500kV circuit breakers. … [PG&E has] insufficient stock on-hand to supply demand for new and higher capacity breakers.[202] As shown in Figure 5, Wood Mackenzie has documented a three-year trend of increasing lead times for delivery of power transformers, with large power transformer (greater than 500 kV) delivery times averaging over three years.

**FIGURE 5** | Delivery Lead Times for Power and Generator Step-Up Transformers *(weeks after receipt of order)*[203]




200 FERC authority to issue data requests can be found in Federal Power Act Sections 301(b) and 309. See FERC, *Order Directing Reports: Modernizing Wholesale Electricity Market Design* (April 21, 2022), Docket AD21-10.

201 North American Electric Reliability Corporation, *2024 Summer Reliability Assessment* (May 2024), p. 7.

202 PG&E, *Response to SB Energy, October 25, 2023 CAISO Transmission Development Forum Stakeholder Comments* (October 25, 2023), p. 2.

203 Wood Mackenzie, *Transformer Market Study 2024 Q2* (June 2024), p. 4. Henceforth, "Wood Mackenzie Transformer Market Study."

Although the existence of supply chain bottlenecks is well documented, it should be noted that the impact of these delays in the context of other schedule constraints on transmission projects is not known. There are no published estimates of the number of transmission upgrade projects materially affected by supply chain bottlenecks, what cost impacts these shortages are causing, or how much longer construction processes are due to supply chain bottlenecks.

**… because many utilities would face regulatory risks related to advance and potentially uncertain procurements, a collective procurement program may require the federal government to provide capital or a financial guarantee.**

A collaborative procurement program targeted at key equipment required for network upgrades could enhance the confidence of manufacturers in future demand, driving increased investment in the needed manufacturing capacity. Such a program should avoid exposing individual transmission owners to unreasonable costs, seeking broader participation that would result in reduced costs of participation for each individual member utility. However, because many utilities would face regulatory risks related to advance and potentially uncertain procurements, a collective procurement program may require the federal government to provide capital or a financial guarantee.

FERC has not addressed supply chain issues in a major order. FERC would play a role in determining the prudency of a collaborative procurement program when reviewing transmission rates. In fact, FERC has approved cost recovery practices for collaborative sparing services, which provide an important precedent for a collaborative procurement program.

### *4B.1. Background on Supply Chain Impact on Construction Schedules and Delays*

As discussed in Appendix 4.4, the US Department of Energy (DOE) has identified limited manufacturing capacity for certain components of large power transformers as a constraint on timely completion of transmission upgrades. Construction of new or expanded manufacturing facilities appears to have been slow to respond to market demand due to concerns about a "bubble," the relatively high cost of capital, and a lack of confidence in a long-term expansion of the market for high-voltage equipment, including but not limited to transformers.

Domestic and North American production capacity for high-voltage transformers falls far short of domestic demand. As reported by DOE in 2022, there are eleven domestic transmission manufacturing facilities with an estimated production capacity of about 343 transformers per year, or roughly one-third of total annual deliveries.[204] In response to the supply chain bottleneck, only five US and four other North American manufacturing facility projects have been completed recently or are under construction.[205]

204 US Department of Energy, *Electric Grid Supply Chain Review: Large Power Transformers and High Voltage Direct Current Systems* (February 24, 2022), p. 15. Henceforth, "USDOE Supply Chain Review."

205 Wood Mackenzie Transformer Market Study, p. 7.

Historically, utilities anticipated delivery of high voltage transformers within ten to twelve months of placing an order.[206] **The impact of supply chain shortages on high voltage equipment delivery schedules can be roughly classified into three categories.**[207]

- The longest delays are affecting the **most customized large power transformers**, with recent orders being scheduled for delivery in three to seven years.[208] Delivery times can vary considerably, as manufacturers may allow customers who have a high volume of orders in a manufacturing queue to assign an existing production slot to one of these transformers. On the other hand, transmission owners or others without an established, high-volume relationship with a manufacturer may not be able to even place an order.[209]
- Shorter delays are affecting simpler, **less customized large and medium transformers**. Transmission operators and other customers that place orders for a significant quantity of the same transformer model are reportedly less affected by supply chain delays. According to one procurement expert, delivery schedules for transformer models with higher production volumes have only increased to about 1 ½ years.
- Some of our sources for this report also raised the issue of delays affecting **high voltage circuit breakers** and other similar equipment, especially over the past year. Average delivery schedules for these equipment types are now close to three years — again, with variation depending on the relationship between the customer and manufacturer as well as the volume and standardization in an order.

Similarly, for generator project developers, delivery times for critical equipment can vary considerably. One procurement expert cites delivery schedules ranging from 20 to 200 weeks for padmount transformers.

While supply chain bottlenecks are almost certainly a key factor in longer construction timelines, there is insufficient evidence to conclude that supply chain bottlenecks are causing a large share of the *delays* in the original estimated in-service dates provided to generation interconnection customers. As noted in Appendix 3, supply chain issues are not frequently cited as a cause of construction delay at either Southern California Edison (SCE) or PG&E. Notably, SCE and PG&E most frequently identify budget constraints and re-prioritization in favor of other types of transmission upgrade projects as reasons for delays in completing transmission project construction — supply chain constraints are identified far less frequently.

The most reasonable understanding is that many transmission owners are factoring in long supply chain lead times into their original construction estimates. This understanding considers the data from California utilities, indirect evidence in other regions, and interviews with practitioners familiar with transmission equipment procurement and manufacturing trends.

206 Wood Mackenzie Transformer Market Study, p. 4.

207 While distribution-voltage transformers are relevant to some generator interconnection projects, this report is focused on transmission-voltage transformers. Raw material supply chains are relevant to both distribution- and transmission-voltage equipment, but manufacturing facility capacity is not generally flexible across equipment classifications. While there is considerable information available regarding distribution transformer supply chains, it is not considered to be highly relevant to this reform proposal.

208 Wood Mackenzie Transformer Market Study, p. 4.

209 This and subsequent similar findings are informed by interviews with industry experts. For similar findings, see: US Government Accountability Office, *DOE Could Better Support Industry Efforts to Ensure Adequate Transformer Reserves* (August 2023), p. 10. Henceforth, "USGAO Transformer Study."

These same data also suggest that supply chain problems may predate the COVID-19 pandemic by about a year. Public commentary on the topic as well as experts interviewed in support of this research tended to associate the onset of construction delays with pandemic-related issues, including supply chain delays.[210] However, as discussed in Appendix 3, available data trends indicate that construction timelines began to increase in roughly 2018, as reflected by the time to place a generation project in service or to complete a network upgrade construction project.

If the increase in construction duration did indeed begin a year or two before the pandemic's economic impact was made manifest, that would suggest that either other non-supply chain factors are driving longer construction timelines (as addressed in Reform 4-A) or the underlying causes of supply chain disruption predate the pandemic and the associated turmoil across global supply chains.

### *4B.2. Existing Strategies to Accelerate Delivery of Key Equipment*

NERC has suggested that transmission owners should mitigate supply chain bottlenecks by ordering surplus inventory in advance.[211] Anecdotally, it appears that some utilities may have the flexibility to make advance procurements of key equipment needed to construct transmission upgrades, including that for new customer load. They may also reassign existing orders (or the assigned manufacturing queue slot) for urgently needed equipment.

However, the opportunity for these procurement strategies to improve construction schedules is limited to those transmission owners that have strong, high-volume relationships with existing manufacturers. It is widely understood that high voltage equipment manufacturers that are relied upon by North American transmission owners are operating at maximum production capacity. Thus, if some transmission operators are able to reduce construction timelines through advance procurement, the inevitable consequence is that other customers will experience even longer timelines for delivery of similar equipment until the supply chain expands.

Manufacturers indicate that longer term equipment purchases, such as the 5- to 10-year commitments made by European utilities, would provide the certainty needed to make manufacturing capacity expansion investments.[212] Opinions vary as to whether utilities can and do place orders for key equipment needed to supply generation interconnection projects prior to fully executing interconnection agreements.[213] According to some transmission owner or operator staff interviewed for this report, it is too risky for utilities to place any orders prior to fully executing an interconnection agreement.

In contrast, an expert in the procurement of such equipment indicated that utilities with more advanced practices have developed relationships that allow for pre-orders with equipment manufacturers. The deposits used to secure pre-orders can be reassigned to different equipment (e.g., a different transformer model) if the utility's priorities change prior to actual manufacturing of the equipment. Such advanced practices are probably less commonly

---

210 USGAO Transformer Study, p. 10.

211 North American Electric Reliability Corporation, *2024 Summer Energy Market and Electric Reliability Assessment*, p. 45.

212 NIAC Report.

213 This impression is based on conversations with staff at several utilities. However, none of those staff could provide detailed documents to verify the details of the processes that are used to expedite equipment availability or the frequency by which those processes are used.

used by smaller utilities. The federal Western Area Power Administration has noted that its regulations require procurement mechanisms that are making it difficult to obtain large power transformers.[214] And the Government Accountability Office noted that it was unable to locate any cooperative or municipal utilities that participate in collective equipment-sharing programs (discussed in Section 4-B.3). Those utilities expressed concerns about cost or were not even aware of the programs.[215]

For some transmission system owners, placing an order prior to fully executing an interconnection agreement may place the company at risk of non-recovery of carrying costs for equipment that is not installed upon delivery from the vendor.[216] Such risks may be limiting the willingness of transmission system owners to voluntarily adopt this practice. Establishing guidance to provide for the prudent use of advance procurement and reassignment of manufacturing queue slots may raise jurisdictional questions. Creating such guidance may be within the jurisdiction of state regulators, which usually have authority to regulate project approval, or it could lie with FERC, which has jurisdiction over the determination of project cost prudence in the rate-setting process.

Currently, utilities may be revising their queued transformer orders to shift equipment away from projects that enable generator interconnection to other projects that are of higher priority to the utility. This possibility is suggested by some evidence from the California reporting data described in Appendix 3.1, but is only found in just a few reported causes for transmission project delays. There are no data sources in other parts of the country that allow for this practice to be studied.

Finally, some have considered whether outsourcing network upgrade construction could reduce construction timelines. As discussed in Appendix 4.1, for projects that involve upgrades to existing equipment or otherwise require a high degree of integration with existing transmission facilities, outsourcing may not always significantly improve schedule certainty.

### *4B.3. Methods to Order Critical Equipment in Advance.*

To resolve supply chain bottlenecks, the evidence suggests that the utility industry needs to enhance manufacturer confidence in the size of the domestic market for high-voltage equipment in a way that also drives investments to address constraints in raw materials, labor, and upstream components. While some utilities may be able to provide manufacturers with a degree of certainty that investments in new manufacturing facilities could be worthwhile, many other utilities will not be able to individually provide the longer-term assurances that appear to be needed.

To overcome the challenges to individual action, utilities could join together in a collaborative procurement program. Broader participation enabled by a collaborative procurement program could help individual transmission owners reduce their exposure to unreasonable cost risks. Many utilities also face regulatory risks related to advance and potentially uncertain procurements.

---

214 John Rohrer, *Supply Chains Impact Power Transmission Systems* (April 23, 2024).

215 USGAO Transformer Study, p. 23.

216 NIAC Report.

Implementing this strategy may require complementary actions from both transmission owners and the federal government. Transmission owners and potentially other parties could build on existing collaborative procurement efforts to provide manufacturers with guarantees of orders for transformers, circuit breakers, and other equipment in short supply. Financial and policy support from the federal government is likely necessary to achieve the scale of orders needed to give manufacturers confidence in investment prospects.

### *Collaborative upgrade purchase program strategy*

Collaborative action by transmission owners is needed because the cost and physical characteristics of large power transformers present challenges to stockpiling by individual transmission owners. The specialized requirements for transportation and storage; purchase cost; and financial carrying cost for large power transformers is a disincentive for speculative purchase and ownership of spare equipment.[217] For example, Nova Scotia Power estimated the 2021 cost to deploy a spare transformer, including disassembly, transport, design and installation to be $1.4 million, in addition to the transformer's estimated $3.0 million cost.[218]

In response to these cost pressures, many utilities already participate in collective procurement arrangements to ensure availability of replacement equipment in urgent circumstances. The electric utility industry has four programs to share spare critical equipment, including transformers, to supply replacement of equipment damaged in catastrophic events. These programs are described in a 2023 report by the US Government Accountability Office (GAO).[219]

### *Key lessons from existing collaborative sparing service subscription programs*

While existing collaborative sparing service programs provide a useful model, a focus on addressing emergency circumstances means that such programs would rarely, if ever, release excess inventory to address construction delays affecting transmission system upgrades. However, there are three key aspects of these programs that can be leveraged into a new collaborative upgrade purchase program.

- **Prudency standard:** In approving Grid Assurance's sparing service program, FERC found that a transmission owner's decision to subscribe to and then acquire spare equipment from Grid Assurance at original cost is prudent.[220] Grid Assurance is a company that a number of US utilities created and subscribed to in order to mitigate the high cost of physical stockpiling, providing its subscribers with immediate access to spare units in certain emergency circumstances. Subscribers to the sparing service identify a required quantity of each class of transmission equipment, then Grid Assurance purchases an "optimal quantity" of each type of spare equipment based on subscribers' "collective identified needs."[221]

---

217 USGAO Transformer Study, pp. 11-12.

218 Note that the $3.0 million cost was estimated to be the same whether the transformer was placed in service immediate or placed in storage, as the cost of commissioning is similar for each delivery option. Nova Scotia Power, Exhibit N-3, CA RIR-9(c, f), Matter No. M09920.

219 USGAO Transformer Study.

220 This decision relied on prior findings that such arrangements avoid higher costs and avoid delays due to procurement and delivery. Subscription costs are classified as Extraordinary Expenditures, which allows for recovery of those subscription costs outside of a general rate case (e.g., in a single-issue ratemaking case). FERC, *Order on Petition for Declaratory Order*, Docket EL16-20, paras 30, 33.

221 In addition to purchasing, securely storing, and maintaining the spare equipment in as-new condition, Grid Assurance assists its subscribers with delivery of the equipment for installation. Spare units are available in the event of physical attack, cyber-attack, an electromagnetic pulse, or catastrophic event such as severe weather or earthquake. *Id.*, paras 12, 14.

- **Forecasting collective procurement requirements: Grid** Assurance has experience developing a process for determining the optimal quantity of equipment to procure based on subscribers' collective needs. This experience could be transferred to a collective upgrade purchase program to reduce the risk that subscribers would procure too much equipment, which is a special risk when utilities do not know exactly what equipment they may need in the future.
- **Financing of carrying and storage costs:** The Grid Assurance model also demonstrates how to simplify financial treatment of carrying and, if necessary, storage costs. A collective upgrade purchase program would likely have to take delivery and then store equipment that subscribers are not positioned to install immediately. Rather than bearing the full cost of delivery and storage of surplus deliveries on an individual basis, Grid Assurance's subscription model demonstrates how those costs can be shared.

### *Business case for collective upgrade purchase program*

A business case for a collective upgrade purchase program would have to overcome at least three key hurdles.

- Subscribers would need to be convinced that the cost risk associated with surplus deliveries would be offset by the advantages of more rapid and predictable delivery of equipment critical to the construction of transmission system upgrades. Grid Assurance, or perhaps one of the other three collective action programs, should be well equipped to undertake analysis of this tradeoff and engage with potential subscribers.
- In order to meaningfully affect the willingness of manufacturers to build additional production capacity for transformers and other critical equipment, the collective upgrade purchase program would require capital to either make deposits on a substantial, long-term equipment order, offer loan guarantees, or otherwise reduce manufacturers' risks. Grid Assurance has not demonstrated the capacity to supply capital at that scale and, in any case, FERC's limitations on single-issue ratemaking could constrain subscribers' opportunity to recover those costs prior to taking delivery of equipment.
- The supplier of the capital or financial guarantee would need to have the patience to maintain that commitment through a production facility construction period of several years and then further through a multi-year period during which the guaranteed equipment orders are fulfilled, and ultimately stored until installation by a member utility.

It is unlikely that utilities, whether investor-owned or public-owned (e.g., cooperatives or utilities owned by municipal, state, or federal government), could supply capital or financial guarantees on an individual or collective basis large enough to convince manufacturers to substantially expand the supply chain. While utilities are currently investing at high levels, many are capital constrained and setting priorities on investments. As discussed in Appendix 3, PG&E and SCE have delayed transmission upgrade projects due to their corporate capital constraints. Recent increases in requests for interconnection of large loads are also creating additional, unanticipated demands for investment of utility capital. Even if utilities are able to assure the financial markets that those costs will be recovered from customers through approved fees or rates, the resulting impacts on key financial metrics may raise the cost of borrowing or otherwise be viewed as unacceptable to financial markets.

### *Need for federal government capital or financial guarantee*

For these reasons, it may be necessary for the federal government to provide the capital or financial guarantee necessary to establish a collective upgrade purchase program. While FERC, state regulators, and Regions are in good position to review this proposal, opine on its merits, and offer further insights as to its design, these entities individually lack the ability to assemble such capital.

One possible mechanism for federal capital or financial guarantee support to the collective upgrade purchase program is Title III of the Defense Production Act (DPA). In 2022, the US Department of Energy (DOE) issued a request for information on possible future use of the DPA to help scale up manufacturing of transformers and electric grid components. Such actions would require Congressional appropriations. Among the potential tools of the DPA described in the request for information are funding for purchases of manufacturing equipment, purchase commitments for transformers and other components, and direct capital assistance for development of a new manufacturing facility.[222] According to the General Accounting Office, "DOE has not yet developed a plan for how to use the information it has gathered from industry to rapidly deploy DPA-funded programs and efforts, should funding become available."[223]

Another federal financial tool to encourage supply chain development is the Qualifying Advanced Energy Project Tax Credit (48C) funded by the Inflation Reduction Act (IRA). The Round 1 Awards announced in March 2024 included tax credits for several grid infrastructure manufacturers.[224] The two largest publicly-announced tax credit awards for grid components are $36 million to TS Conductor for a facility to manufacture advanced high-capacity conductors in Indiantown, FL and $18 million to Siemens Energy for a $150 million large power transformer manufacturing facility in Charlotte, NC.[225] The second round of applications for the remaining $6 billion in tax credits is currently being reviewed.[226] However, it isn't clear that a tax credit could be used to establish capital or financial guarantees for a collaborative procurement program.

Several bills introduced in the 117th Congress include proposals to address the shortage of transformer supplies.[227] However, there does not appear to be any currently appropriated funding available that the federal government could use to supply capital or loan guarantees to assist with establishing a collective upgrade purchase program.

222 US Department of Energy, *Request for Information (RFI) on Defense Production Act* (October 11, 2022).

223 USGAO Transformer Study, p. 22.

224 US Department of Energy, *Department of Energy, Biden-Harris Administration Announces $4 Billion in Tax Credits to Build Clean Energy Supply Chain, Drive Investments, and Lower Costs in Energy Communities* (March 29, 2024).

225 US Department of Energy, *Applicant Self-Disclosed 48C Projects* (June 21, 2024).

226 US Department of Energy, *Qualifying Advanced Energy Project Credit (48C) Program* (accessed June 28, 2024).

227 Congressional Research Service, *Electric Power Transformers: Supply Issues* (November 16, 2022).

# APPENDIX 1.

## KEY FERC POLICY ADDRESSING INTERCONNECTION

### 1.1. FERC Order No. 845: Reforms to the Generator Interconnection Process, Including Energy Storage

In April 2018, FERC issued Order No. 845 to enhance the interconnection process by supporting energy storage and allowing flexibility for interconnection customers.[228] Order No. 845 and all other interconnection-related orders modified Order No. 2003, which established standardized interconnection procedures. Order No. 845 updated the definition of a generating facility to clearly include battery storage facilities, both co-located and stand-alone facilities. It allowed interconnection customers to request interconnection service below their full generating capacity, allowing flexibility in certain projects with variable energy production (e.g., wind turbines). Order No. 845 also incorporated surplus service requests into the pro forma tariff so that an interconnection customer's unused allocated capacity can be utilized by another project.

Order No. 845 added requirements set to improve timing and financial certainty for customers. It required transmission owners to expand the option for customers to unilaterally elect to self-build upgrades in all instances, not only in the event of construction delays from the transmission provider.

Order No. 845 enabled greater ability for the customer to make modest changes in the generation technologies they are using, without triggering the "material modifications" that previously could result in significant delays or loss of queue spots.

Finally, Order No. 845 required transmission providers to offer provisional interconnection service to their interconnection customers, offering customers the ability to interconnect a project before all studies or necessary transmission upgrades are complete, subject to operating restrictions.

228 FERC Order No. 845.

## 1.2. FERC Order No. 2023: Generator Interconnection Process Reform

On July 28, 2023, FERC issued Order No. 2023, designed to enhance the processes and agreements used by electric transmission providers to integrate new generating facilities into the existing transmission system.[229] Through these reforms, FERC sought to address the significant delays and backlogs associated with generator interconnection to the bulk transmission system.

Traditionally, transmission providers studied interconnection requests on a "first-come, first-served" basis, known as the serial process. This approach worked well when the volume of interconnection requests was manageable and primarily consisted of large natural gas projects which made up almost all of the requests before and after FERC Order No. 2003. However, with the advent of numerous wind, solar, and battery storage projects which can be developed by hundreds of entities at thousands of locations, the process has become overburdened. Order No. 2023 mandated a transition to a "first-ready, first-served" cluster study process, where interconnection requests are grouped and studied together. This new method is expected to improve efficiency and reduce backlogs by handling requests in clusters rather than individually.

To facilitate informed decision-making, FERC required transmission providers to maintain publicly available heatmaps that display available transmission capacity. These visual tools are intended to help prospective interconnection customers identify optimal points for interconnection.

The final rule also required implementation of stricter financial readiness and site control requirements. Interconnection customers must now provide higher study deposit amounts, demonstrate 90% site control at the time of their interconnection request, and show 100% site control at the time of executing the facilities study agreement. These measures aim to focus transmission planners' resources on projects that are most ready to proceed and reduce queue size by discouraging applications from projects that are not ready.

The rule introduced firm deadlines and penalties for transmission providers that fail to complete interconnection studies on time, replacing the previous "reasonable efforts" standard which had little to no enforcement. While the rule also sets deadlines for notifying and conducting "affected system studies" (regarding impacts on neighboring systems), there are no automatic penalties for failure to meet those standards.

To reduce cost uncertainty, Order No. 2023 allowed for the interconnection customer to request optional studies from the transmission provider after receiving the cluster study results. The study specifies the required technical data, the customer's assumptions, and the estimated cost of interconnection. The study will analyze the impact based on the customer's assumptions and identify necessary facilities and upgrades, providing cost estimates for informational purposes.

To help reduce costs associated with network upgrades, Order No. 2023 emphasizes increased consideration of technological advancements. Multiple resources may co-locate on a shared site behind a single point of interconnection and Order No. 2023 requires transmission providers

229 FERC Order No. 2023.

to consider alternative transmission technologies. This rule also requires accurate modeling of non-synchronous generating facilities like wind, solar, and battery storage and establishes requirements for non-synchronous generating facilities to demonstrate capability to ride-through system disturbances without momentary cessation.

## 1.3. FERC Order No. 1920: Transmission Planning and Cost Allocation

On May 13, 2024, FERC issued Order No. 1920, aimed at enhancing long-term regional transmission planning and cost allocation.[230] Order No. 1920 substantially updates the requirements of Order No. 1000, adding a requirement that transmission providers engage in long-term planning to address anticipated future transmission needs. Each transmission operator must produce a regional transmission plan that looks at least 20 years into the future, identifying long-term needs and necessary facilities. Planning must occur at least once every five years.

Order No. 1920's reforms allow for flexibility in how transmission providers evaluate and select these facilities. Providers can use existing evaluation methods and selection criteria from existing Order No. 1000 processes, if these methods are demonstrated to be consistent with the requirements of the final rule. FERC intended this flexibility to enable transmission providers to tailor their processes to best meet regional needs while ensuring stakeholder engagement and consideration of various transmission needs.

The following sections focus on aspects of the rule most closely related to generator interconnection.

### *1.3.1. Multi-factor, multi-benefit planning.*

In addition to reforms focused more directly on integrating generator interconnection needs with existing transmission planning processes, Order No. 1920's shift towards proactive multi-factor and multi-benefit long-term planning is likely to further improve generator interconnection outcomes. This type of planning addresses deep backbone network expansions organized at the system level rather than through incremental local upgrades resulting from the interconnection process.

Order No. 1920 built on experience with MISO's Multi-Value Projects and other proactive planning processes which demonstrated more efficient timelines and lower costs for interconnection of generators in areas with planned upgrades. The proactive multi-benefit, multi-factor scenario-based planning in Order No. 1920 benefits customers because the various needs and uses of transmission can all be optimized together to plan an efficient network.

### *1.3.2. Informing planning with interconnection study results.*

In addition to generally improving interconnection by moving more network upgrades into the planning process, Order No. 1920 also has provisions specifically addressing overlaps with

230 FERC Order No. 1920.

the interconnection process. Order No. 1920 specifically directs existing transmission planning process to consider interconnection-related transmission needs associated with generator interconnection requests.[231]

It is widely understood that interconnection queues will continue to include projects that will not ultimately be developed. While Order No. 1920 does not direct that planners assume that all proposed projects will be placed in service, it directs planners to consider generation interconnection queues as one indication of the future market portfolio and locations of future generation. In particular, FERC believed that "the existence of a large number of interconnection requests in a certain area, even if some of those requests are speculative, indicates that generation developers have an interest in interconnecting resources in that area, which Long-Term Scenarios should take into account."[232]

Order No. 1920 also addresses the overlap of planning and interconnection by directing transmission providers to incorporate certain network upgrades originally identified through the generator interconnection process.[233] By doing so, the reforms aim to ensure that more efficient or cost-effective transmission expansions can be achieved through regional planning, thus enhancing competition and facilitating access to lower-cost generation.

To qualify for evaluation under these reforms, an interconnection-related network upgrade must meet specific criteria including cost, voltage, and planning status. Projects must be identified in at least two interconnection queue cycles during the preceding five years but not be currently planned for or under development through the generator interconnection process.

### *1.3.3. Cost Allocation*

Order No. 1920 continues to employ the Commission's "beneficiary pays" cost allocation approach, as previously adopted in Order No. 1000 and as the Federal Power Act has been interpreted by the courts.[234] Courts have noted that the "beneficiary pays" approach stems from the "cost causation" principle,[235] and have subsequently explained that "causing" or "benefiting" from a transmission project each satisfy the requirements of the Federal Power Act.[236] While Order No. 1920 did not address cost allocation as it relates to the interconnection queue process, the order did cite relevant court decisions that have found that interconnection-related network upgrades have broad beneficiaries.[237]

231 FERC Order No. 1920, paras. 1106-1121.

232 FERC Order No. 1920, para. 473.

233 "This is the case where interconnection-related network upgrades of substantial cost are repeatedly identified to address interconnection-related transmission needs, but those needs continue to go unresolved through the generator interconnection process." FERC Order No. 1920, para 1110.

234 See, e.g., Illinois Commerce Commission v. FERC, 576 F.3d 470 at 476 (7th Cir. 2009), Midwest ISO Transmission Owners v. FERC, 373 F.3d 1361, 1368 (D.C. Cir. 2004).

235 See, e.g., KN Energy, Inc. v. FERC, 968 F.2d 1295, 1300 (D.C. Cir. 1992) ("all approved rates [must] reflect to some degree the costs actually caused by the customer who must pay them").

236 "FERC is not authorized to approve a pricing scheme that requires a group of utilities to pay for facilities from which its members derive no benefits, or benefits that are trivial in relation to the costs sought to be shifted to its members … To the extent that a utility benefits from the costs of new facilities, it may be said to have 'caused' a part of those costs to be incurred, as without the expectation of its contributions the facilities might not have been built, or might have been delayed." Illinois Commerce Commission v. FERC, 576 F.3d 470 at 476 (7th Cir. 2009)); and "[W]e evaluate compliance with this unremarkable principle by comparing the costs assessed against a party to the burdens imposed or benefits drawn by that party." Midwest ISO Transmission Owners v. FERC, 373 F.3d 1361, 1368 (D.C. Cir. 2004)

237 FERC Order No. 1920, n. 2370. (Citing Entergy Svs., Inc. V. FERC, 391 F.3d 1240, 1247-48 (2004).)

In addition to generally improving interconnection by moving more network upgrades into the planning process, Order No. 1920 also has provisions specifically addressing overlaps with the interconnection process. Order No. 1920 specifically directs existing transmission planning process to consider interconnection-related transmission needs associated with generator interconnection requests.[238]

## 1.4. FERC Orders on Retired Generation Replacement

FERC's orders providing a faster track for the replacement of retired generation also provide important background for future reform. Certain regions and transmission providers have developed a unique fast track process enabling enhanced replacement of retiring resources, while others simply consider replacement units as part of the standard interconnection queue.

### *1.4.1. MISO and SPP retired generation replacement orders.*

FERC has approved generator replacement processes for MISO and SPP that allow projects to advance in the interconnection queue more rapidly.[239] Generator replacements present an opportunity for reduced interconnection timelines because the new interconnection request is utilizing capacity which already exists on the transmission system. MISO and SPP's proposals followed Order No. 2003, which required public utilities that own, control, or operate transmission facilities to file standard generator interconnection procedures and agreements to provide interconnection service to generating facilities. Under the FERC-approved processes, the generator owner has a limited period of one year in which it may file for re-assignment of the associated interconnection rights.

The MISO and SPP processes are available for generator replacements at the same electrical point of interconnection (POI) as the legacy generator. Replacements are eligible when

- The requested interconnection service is for an equivalent or lower capacity (MW) and at the same level of service as the existing interconnection service; and
- The requested interconnection for the replacement generating facilities will not have a material adverse reliability and operational impact on the transmission system compared to that of the existing generating facilities.

Generation replacement projects that fail to meet either requirement are reviewed using the normal interconnection study process. SPP's process varies in one respect from MISO, where it includes a provision for the transfer of a network resource designation from an existing generating facility to a replacement generating facility.[240]

---

238 FERC Order No. 1920, paras. 1106-1121.

239 FERC, *Order Accepting Tariff Revisions* (June 30, 2022), Docket ER20-1536; and FERC, *Order Accepting Tariff Revisions* (May 15, 2019), Docket ER19-0165.

240 FERC, *Order Accepting Tariff Revisions* (June 30, 2022), Docket ER20-1536.

### *1.4.2. NYISO capacity rights transfer process*

NYISO permits existing generators to transfer Capacity Resource Interconnection Service (CRIS) rights and associated deliverable capacity even if there is a change in the fuel source. When an existing generator deactivates and commissions a new resource at the same electrical location, the CRIS rights can be transferred.[241]

### *1.4.3. ISO-NE capacity replacement relies on capacity market rules*

ISO-NE's rules and practices for capacity replacement are derived from its Forward Capacity Market (FCM) rules. According to these rules, a previously counted capacity resource, including deactivated or retired units, can participate as a New Generating Capacity Resource if it meets two conditions: it must adhere to $ per kW bid thresholds and participate in the FCM. The bid price thresholds for repowered resources are set at $200 per kW or higher. Additionally, no initial queue evaluation is needed for the repowered resource unless a material modification is found.

### *1.4.4. PJM Capacity Interconnection Rights Reform Proposal*

PJM may soon have a new generation replacement process.[242]. Under PJM's construct an existing generator can use, transfer, or assign Capacity Interconnection Rights ("CIRs") to third parties. Once transferred, the holder can submit a new interconnection request within one year of the deactivation date. However, unlike the MISO and SPP processes that enable expedited replacement among affiliates, PJM's approach requires replacement resources with transferred CIRs to be evaluated and processed as part of the cluster study process. This extra step differentiates PJM's proposal and causes unnecessary delay. Retired generation replacement in non-RTO/ISO regions

The generator replacement process for non-RTO/ISO regions is somewhat different, and generally follows the approach approved by FERC for Dominion Energy South Carolina, which was in turn based on the MISO and SPP process.[243] Because vertically integrated transmission providers raise concerns of market power and discrimination, the generator replacement process is subject to oversight by independent Generation Replacement Coordinators, as discussed further in Section 3-E.5. Following approval of Dominion's process, other transmission operators submitted similar proposals. To date, FERC has approved such processes for Xcel Colorado, Duke Energy Carolinas, PacifiCorp, and Arizona Public Service Company.[244]

Under the non-RTO/ISO generation replacement processes, generator owners may submit a replacement request for the facility one year in advance of unit retirement. The proposed new generator must be operational within three years of the retiring generator's decommissioning date. Technical studies are conducted to assess the impact of the new generator on the existing

241 NYISO, *Open Access Tariff*, Attachment S, Section 25.9.4

242 PJM, *Capacity Interconnection Rights (CIR) Transfer Process Education,* Interconnection Analysis Department, (July 31, 2023).

243 Dominion Energy S.C., Inc., ER-20-1668 (2020).

244 Excel Colorado, *ER21-1287* (2021); Duke Energy Carolinas, LLC, *180 ER22-2007* (2022); PacifiCorp, *ER23-407* (2023); Arizona Public Service Company, *ER23-1272*.

grid infrastructure, ensuring it does not have a material adverse impact on transmission system reliability under the oversight of the replacement coordinator.

### 1.5. Policy and Legal Standards for Cost Allocation

From a policy standpoint, there are certain guidelines from FERC policy and the Federal Power Act that must be followed. US courts have interpreted the Federal Power Act to require "beneficiary pays" pricing. For example, a 2009 appeals court decision held that,

> FERC is not authorized to approve a pricing scheme that requires a group of utilities to pay for facilities from which its members derive no benefits, or benefits that are trivial in relation to the costs sought to be shifted to its members.[245]

In FERC Order No. 1000, FERC explained the beneficiary pays principle as,

> [T]he principles-based approach requires that all regional and interregional cost allocation methods allocate costs for new transmission facilities in a manner that is at least roughly commensurate with the benefits received by those who will pay those costs. Costs may not be involuntarily allocated to entities that do not receive benefits.[246]

Most recently, in Order No. 1920 FERC stated,

> When it comes to the critical question of "who pays," we are providing transmission planners with the maximum flexibility we can legally allow in order to facilitate negotiated, regionally appropriate solutions. And, as part of a multi-pronged approach to protecting customers, we are requiring transmission planners to reevaluate any previously selected transmission facility when the actual or projected costs of that facility significantly exceed the cost estimates used during selection. Finally, we are also providing states with unprecedented, expanded opportunities to work with transmission providers to shape the cost allocation approaches of their regions, while meeting the beneficiary pays requirement that is the foundation of cost causation under the FPA's just and reasonable standard.[247]

The legal and regulatory standard clearly requires that the equity and principles adopted in any cost allocation mechanism must be consistent with the "beneficiary pays" standard.

The beneficiary pays standard is perhaps best explained in the following commentary in the concurring opinion on FERC Order No. 1920:

> … A bedrock requirement of this final rule is that customers will only be required to pay for a share of a Long-Term Transmission Facility to the extent they benefit from that facility. … While we provide transmission planners, in cooperation with their state regulators, ample flexibility to determine how to satisfy that bedrock requirement, any cost allocation methodology that causes customers to pay for projects from which they

245 Illinois Commerce Commission v. FERC (August 6, 2009), p. 9. *ICC v. FERC I*, 576 F.3d at 476.

246 FERC Order No. 1000, para 10.

247 FERC Order No. 1920, para 8.

do not benefit—or to pay a cost share out of proportion to the benefits they draw from the project—would be patently unjust and unreasonable. That is black letter law under the FPA,[248] which we have expressly incorporated into the requirements of this final rule.[249]

### *Embedded (average) cost pricing vs incremental (marginal) cost pricing*

Another key cost allocation concept is the prevalence of embedded (or average) cost pricing over incremental (or marginal) cost pricing. Embedded cost pricing collects the total cost of all transmission facilities from all customers equally based on some billing determinant, such as peak demand. Incremental cost pricing collects revenues from each customer based on the additional system cost incurred to serve that customer. Generally speaking, the "beneficiary pays" standard is more closely aligned with embedded cost pricing because, under incremental cost pricing, there can be customers for whom there is no additional system cost incurred and hence they would pay no (or very little) towards the total system cost.[250] For example, embedded (or average) cost pricing is the standard basis of transmission service under FERC Order No. 888.

FERC also allows incremental pricing, particularly for generator interconnection. This policy was allowed by FERC in Order No. 2003, which established interconnection policies, explaining that the "but for" costs created and faced by the interconnection customer are consistent with competitive markets.[251] In Order No. 2003, FERC did not prohibit the use of participant funding in Regions with independent oversight as long as valuable transmission congestion rights were conveyed to the generator.[252] Of the FERC-jurisdictional Regions, all but CAISO utilize participant funding and assign network upgrade costs to interconnection customers.[253]

Order No. 2023 only modified the Commission's *pro forma* generator interconnection procedures, leaving untouched the existing practices of "participant funding" that had been approved through independent entity variations in certain Regions.[254] In practice, marginal cost pricing with participant funding can lead to challenging or seemingly illogical outcomes. Sometimes differences that are arbitrary or not very meaningful such as small differences in queue timing can lead to very large differences in assessed costs, even for similar projects. As projects enter or exit the interconnection queue, major changes can occur in other projects' cost assignment. Order No. 2023 sought to address these challenges in part by limiting the timeframe over which network upgrades can be allocated to future clusters, increasing cost

248 *See City of Lincoln v. FERC*, 89 F.4th 926, 930 (D.C. Cir. 2024) ("The FPA's just and reasonable standard incorporates a cost-causation principle."); *Old Dominion Elec. Coop. v. FERC*, 898 F.3d 1254, 1255 (D.C. Cir. 2018) ("Under the [FPA], electric utilities must charge just and reasonable rates. For decades, the Commission and the courts have understood this requirement to incorporate a cost-causation principle—the rates charged for electricity should reflect the costs of providing it." (citations omitted)); *see also BNP Paribas Energy Trading GP v. FERC*, 743 F.3d 264, 268 (D.C. Cir. 2014) ("[T]he cost causation principle itself manifests a kind of equity. This is most obvious when we frame the principle (as we and the Commission often do) as a matter of making sure that burden is matched with benefit."). (Citation in original.)

249 FERC Order No. 1920, Concurring Opinion, para. 22.

250 Another problem with an "ideal" incremental (or marginal) cost system is that it can, and usually will, result in collecting more or less revenues than are necessary to cover the total system cost. Incremental or marginal cost systems require adjustment factors or other accounting measures to balance revenues with costs.

251 FERC Order No. 2003, para 702.

252 FERC Order No. 2003. FERC limited this cost allocation method to Regions under the theory that the independence of the Regions would lead to non-discriminatory determinations of incremental cost.

253 CAISO generally assigns those costs to interconnection customers, but then reimburses those costs from its transmission service revenues if the generator is in commercial operation.

254 FERC Order No. 2023, para. 457. Citing Nev. Power Co., 182 FERC ¶ 61,048, at para 50-51 (2023) (describing the cost allocation requirements for network upgrades as the Commission's Order No. 2003 "but for requirements").

certainty for customers.[255] Notably however, despite the ability to centrally plan for several interconnection requests through a cluster, Order No. 2023 does not push transmission providers to pre-plan such transmission facilities, which was subsequently enabled in Order No. 1920.

In theory, assigning costs to interconnection customers should induce the location of generators to parts of the grid where less costly upgrades are needed. However, the same benefit can be obtained by transmission planning with identified generation needs, providing the ability either for interconnection customers to access interconnection service for a set fee known in advance (as envisioned by SPP), or allocating the ultimate costs back to ratepayers (as in California).

## 1.6. Establishing the Need for Reform in Prior and Future FERC Action

FERC has acted multiple times over the years on interconnection policy when it found that existing processes and practices were not satisfying the Federal Power Act's just and reasonable rate or undue discrimination standards. FERC found that undue discrimination existed in 1996 (Order No. 888) and again in 2003 (Order No. 2003), relying on similar findings to require foundational open access reform and standardization of large generator interconnection procedures across the country for its jurisdictional utilities.[256] The Supreme Court reviewed and affirmed FERC authority to remedy undue discrimination with generic industry-wide action.[257] FERC acted again in 2018 in Order No. 845 to remove inefficiencies in the interconnection process. In 2023, FERC found that rates, terms, and conditions were unjust, unreasonable, and unduly discriminatory and in need of further process reforms.[258]

For FERC to take further action under Section 206 of the Federal Power Act, it must find that the rates, terms, and conditions cause higher rates (unjust and unreasonable) or are unduly discriminatory, or both. It can do so for any individual transmission provider, or all of them on a generic basis. In the case of interconnection, one recurring concern addressed by FERC is discrimination in the form of vertical market power, whereby a transmission owner can use its transmission services to harm competitors to the generation it owns. FERC has issued multiple orders (Orders No. 888, 2003, 845, 890, 1000 and 2023) that relied in part on undue discrimination as well as unjust and unreasonable rates. FERC has often stated its goal as increasing competition in generation markets and mitigating this potential for the exercise of vertical market power.

Transmission providers are not limited to actions or policies specifically directed by FERC and may act on their own initiative under FPA Section 205 with process improvements as they often do.

255 FERC Order No. 2023, para. 486.

256 "The Federal Energy Regulatory Commission's authority to require the addition of the Final Rule interconnection agreement and Final Rule LGIP to the OATT derives from its findings of undue discrimination in the interstate electric transmission market that formed the basis for Order No. 888." FERC Order No. 2003, para. 4.

257 New York v. FERC, 535 U.S. 1. (2002). Notably, in a dissent, Justices Thomas, Scalia, and Kennedy would have gone further in reinforcing FERC's authority, "I disagree with the deference the Court gives to FERC's decision not to regulate transmission connected to bundled retail sales."

258 FERC Order No. 2023, para 27.

# APPENDIX 2.

## REVIEW OF KEY REGIONAL REFORMS AFFECTING GENERATION INTERCONNECTION

Even before FERC published Order No. 2023, most Regions, and many other transmission providers, initiated reforms to manage increasing queue backlogs, speed up queue processing, and better coordinate network upgrades for new generation. These efforts reflect transmission providers' and stakeholders' recognition of the many of the same problems identified here and in the Order No. 2023 process. This section highlights promising ongoing and recently approved reforms that extend beyond the requirements of Orders No. 2023 and No. 1920. These ongoing reform efforts directly inform this report's recommended reforms.

### 2.1. CAISO Interconnection Reforms

CAISO's forthcoming compliance filing with FERC Order No. 2023 is anticipated to go beyond the specific requirements in several important areas. In addition to adopting the Commission's proposals in areas such as project site control requirements, entry fees, and study deposits, CAISO will also treat projects with co-located technologies as a single aggregated project, such as solar PV and battery energy storage systems seeking different deliverability statuses.[259]

#### *2.1.1. Geographic Differentiation in Interconnection Study Processes*

One distinctive part of CAISO's proposal is its zonal approach, building on a transmission planning process that proactively identifies and constructs transmission to enable generator interconnection in zones with projected resource additions.[260] The zonal approach provides developers clear signals on whether existing or expanded transmission capacity will be available in certain identified locations, more efficiently integrating the queue study process with CAISO's transmission expansion plan.

259 CAISO, *2023 Interconnection Process Enhancements: Track 2 Final Proposal* (June 5, 2024), p. 36. Henceforth, "CAISO 2023 Proposal."
260 CAISO 2023 Proposal, p. 17.

Within these zones, CAISO identifies an amount of transmission process deliverability (TPD), or the amount of headroom available for streamlined interconnection access. Generation projects seeking access to this deliverable capacity are then scored against tariff criteria, explained further below. High-scoring projects will be eligible to enter the cluster study, apply for TPD, and, if placed into commercial operation, become eligible for reimbursement of network upgrades. For projects seeking to interconnect in zones with less than 50 MW of available deliverability capacity, CAISO's merchant deliverability process allows funding of network upgrades by interconnection customers without opportunity for reimbursement.[261] CAISO's proposed merchant deliverability option will require interconnection customers to place an additional readiness deposit for the network upgrades upon application to the queue.

### *2.1.2. Cap and Scoring System for TPD Status*

As part of CAISO's zonal approach, projects are scored to determine which are eligible to be studied for TPD status. CASIO proposes to cap these projects at 150% of zonal capacity, a level that CAISO expects it can reasonably manage and enable successful throughput.[262] Projects are scored in three categories of similar weight, as follows, until a 150% capacity cap is reached. There is a tie-breaker mechanism in place in case of a tie.[263]

- **Commercial Interest** would be determined on the basis of interest demonstrated by wholesale customers, particularly Load Serving Entities (LSEs).[264] Prior to the interconnection request window, interconnection customers, LSEs, and other prospective wholesale customers will engage in marketing activities. Each LSE will be allocated points that it will assign to projects. Points from other wholesale customers will be based on verifiable interest.
- **Project Viability** would be based on the percentage completion of the engineering design plan, validated against industry standards. Expansion of existing facilities would be awarded extra points.[265]
- **System Need** points would be awarded to projects that provide local resource adequacy in areas with demonstrated need and to long lead-time resources meeting specific public utility commission resource portfolio requirements.[266]

### *2.1.3. Study Process for Energy-Only Resources*

Projects that do not wish to obtain deliverability status (i.e., eligibility to count towards resource adequacy requirements) are eligible for two study process options.[267] For projects in zones identified in the integrated resource plan (IRP) with an energy-only resource need,

261 CAISO 2023 Proposal, p. 73.

262 CAISO 2023 Proposal, p. 40.

263 CAISO 2023 Proposal, p. 55. The DFAX represents the change (or sensitivity) of active power flow on a transmission asset with respect to a change in injection at the generator bus and a corresponding change in withdrawal at the reference system. In generation interconnection studies, a study generator must satisfy both DFAX and overload requirements to be required to mitigate the overload. Historically, DFAX has been used as a technical means to identify new service requests responsible for upgrades.

264 CAISO 2023 Proposal, p. 56.

265 CAISO 2023 Proposal, p. 61.

266 CAISO 2023 Proposal, p. 62.

267 CAISO 2023 Proposal, pp. 36-37, 78-89.

CAISO is proposing a "reimbursement option" that provides interconnection customers with reimbursement for reliability network upgrade costs after commercial operation. Reimbursement option projects would be scored using the same three metrics described above (Appendix 2.1.2), but the 150% cap is based on the zonal energy-only need from the IRP.

CAISO is also proposing a non-reimbursement option for energy-only projects that are not located in zones with an energy-only need or otherwise opting not to be scored. These projects can interconnect but are ineligible for reimbursement of network upgrade costs. Accordingly, they do not need to submit scoring information or meet geographic requirements; they are automatically eligible to be studied and then assigned network upgrade cost responsibility.

## 2.2. California Transmission Project Review Process

The California Public Utilities Commission (CPUC), CAISO, and FERC have undertaken a series of reforms to provide greater oversight, opportunity for consideration of project alternatives, and transparency in reviewing transmission projects. The most recent reform establishes the Transmission Project Review (TPR) process.[268] In establishing this process, the CPUC found:

- California's three largest transmission owners' collective rate base increased by over 350% between 2008 and 2023,
- "A majority of transmission projects have received no review and approval by the CAISO or the Commission,"[269]
- Recordkeeping on transmission projects is scattered across unintegrated systems,
- Transmission owners' "procedures for planning and prioritizing projects are inadequate and often *ad hoc,"*[270] and
- Complexity and congestion of the CAISO's generator interconnection queue has resulted in existing reporting falling short of the information needed by interconnection customers.[271]

The TPR will also replace CAISO's Transmission Development Forum. The forum provided information on the status of CAISO-approved transmission projects, including both system transmission planning projects and network upgrades to support generator interconnection.[272]

The TPR requires transmission owners to provide semi-annual data for transmission projects with capital additions to rate base in the past five and next five years, with budgets of more than $1 million. The projects included in this reporting process include CAISO-approved,[273] utility self-approved, and network upgrades needed for generator interconnections. The review process also includes review of the transmission owner's "current asset management procedure documents relied on for identifying, proposing, authorizing, planning, prioritizing, budgeting, and executing Projects."[274] The review process for stakeholder engagement includes semi-

268 CPUC E-5252.
269 CPUC E-5252, p. 2.
270 CPUC E-5252, p. 6.
271 CPUC E-5252, p. 8.
272 CAISO, *Transmission Development Forum,* (January 21, 2022), p. 5-6,
273 The process is not intended to revisit projects approved by the CAISO pursuant to a FERC tariff. CPUC E-5252, p. 24.
274 CPUC E-5252, p. 3.

annual meetings and transmission owners' responses to written comments.

The TPR was established to require information from public utilities and does not rely on ratemaking authority over transmission assets or require transmission planning.[275] The review process is modeled on prior reporting and stakeholder processes required because of negotiations with the CPUC and other parties in their most recent FERC rate cases. While the two most comprehensive processes did achieve improved transparency, as discussed in Section 3.1, those processes were set to expire at the end of 2023.[276]

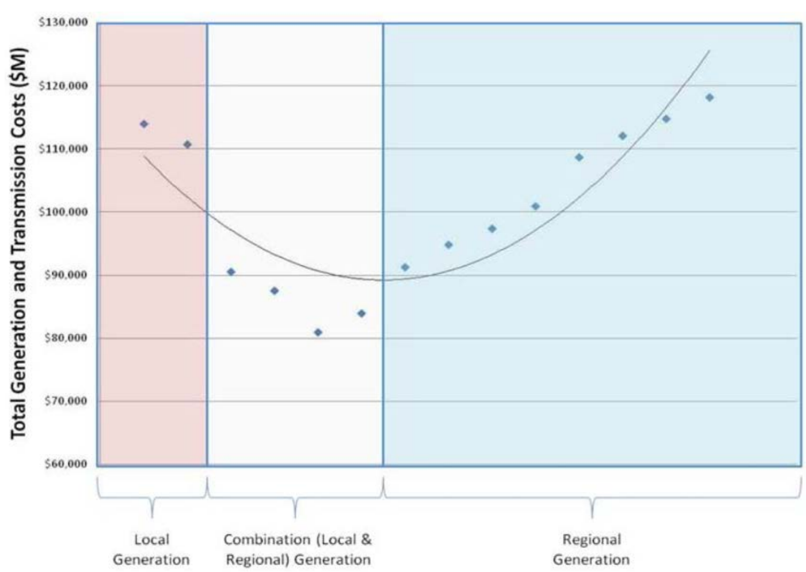
## 2.3. MISO's Planning Reforms

### *2.3.1. MISO: 2011 MVP and 2022 LRTP proactive transmission upgrade initiatives*

MISO has twice successfully used proactive planning to drive major transmission upgrades when its interconnection queue has gotten bogged down with the same vicious cycle of problems that are plaguing interconnection queues across the country.

In its Regional Generator Outlet Study (RGOS) report in 2011, MISO identified renewable resource zones and pro-actively planned transmission to minimize total transmission and generation cost by accessing lower-cost wind resources. MISO's use of a synchronized generation and transmission planning approach to minimize total costs to ratepayers is illustrated in Figure 6.

**FIGURE 6** | **MISO's Regional Generator Outlet Study (2011), Comparison of Generation and Transmission Cost Scenarios[277]**




275 CPUC E-5252, p. 4-5.

276 CPUC E-5252. The transmission owners are also required to report on transmission projects related to generator interconnection, and two have proposed eliminating that separate reporting requirement on the basis of duplication of effort. Southern California Edison & San Diego Gas & Electric, *Petition to Modify Decision 06-09-003*, Docket No. I.00-11-001, p. 6-7, (November 14, 2023).

277 MISO, *Regional Generation Outlet Study* (November 19, 2010), p. 33.

MISO's RGOS findings led to the Multi-Value Projects (MVP) process. In the MVP process, MISO developed a portfolio of projects to maximize multiple benefits of transmission across multiple drivers of needs, including economics, reliability, and public policy needs. MISO's planning approach spread planned transmission projects across the MISO footprint to ensure that all zones received projects and had a strong benefit-to-cost ratio, ensuring broad support for the overall portfolio. MISO later found that the MVP portfolio increased market efficiency, deferred generation investment, facilitated wind power investment, and enabled future transmission investment, with a total of $22-74 billion in benefits compared to $10-22 billion in costs.[278] Moreover, the MVP plans drove improvements to interconnection even before the new lines were energized; as soon as the MVP plans were approved, the projects were included in the baseline cases used in interconnection studies, immediately impacting the cost and schedule for many generation projects.

In 2022, MISO updated its MVP approach with its multi-tranche Long-Range Transmission Planning process. The Tranche 1 portfolio was adopted in 2022 and a Tranche 2 portfolio is currently in development.[279] However, the 10-year gap between the initial MVP portfolio and the Tranche 1 portfolio left the MISO system with insufficient capacity to support the interconnection of new generation resources, resulting in significant delays in its interconnection queue that continue to persist today.

### *2.3.2. MISO's Proposed Cap on Cluster Study Capacity*

In January 2024, FERC acted on two interconnection reform proposals from MISO. MISO's first proposal was accepted, adopting processes similar to those required by Order No. 2023 for updated milestone payments, an automatic withdrawal penalty, and expanded site control requirements for interconnection facilities.[280] However, FERC rejected MISO's second proposal for a capacity cap on project applications.[281]

MISO's proposal would have established a cap for each interconnection cycle using a formula that considers shoulder-season load and minimum generation of existing and prior-queued resources, but with several project exemptions.[282] FERC rejected the proposal, even though it found that "a cap in some form could be beneficial."[283] FERC emphasized three objections to MISO's proposal. First, it objected to the use of uncapped project exemptions, which could dilute or erase the benefits of imposing a cap.[284] Second, FERC objected to the "priority access to the generator interconnection process for the exempted classes of interconnection requests," as MISO placed "no inherent practical limitations" on exempted projects.[285]

---

278 MISO, *MTEP17 MVP Triennial Review Report* (September 2017), p. 6.

279 Utility Dive, *MISO Board Transmission Plan Midcontinent Renewables* (July 26, 2022).

280 MISO, *Energy and Operating Reserve Tariff Generator Interconnection Procedures Improvements* (November 3, 2023), Docket ER24-340, p. 16.

281 FERC, *Order Accepting in Part and Rejecting in Part Tariff Revisions* (January 19, 2024), Docket ER24-341, para 172-183. Henceforth, "FERC ER24-341 Order."

282 MISO, *Energy and Operating Reserve Tariff, Interconnection Queue Cap* (November 3, 2023), Docket ER24-341, Tab A, p. 32

283 FERC ER24-341 Order, para 172.

284 FERC ER24-341 Order, para 173.

285 FERC ER24-341 Order, para 176-177.

FERC's third objection related to MISO's exemption for projects reviewed under MISO's existing expedited interconnection process for replacement generation facilities. FERC found that MISO's justification for exempting facilities with replacement generation interconnection agreements was insufficient.[286]

FERC also raised concerns about MISO's process for measuring the "load remaining to be served after existing and prior queue generation is dispatched" and its failure to "account for the region's resource adequacy needs in determining how the cap will be calculated."[287] FERC found arguments persuasive that the "proposed cap would only guarantee sufficient resources for the lowest growth scenario" and that it is not possible "to determine whether MISO can ensure resource adequacy under the cap."[288]

MISO's revised cap proposal (still under development) would cap each cluster study to 50 percent of regional peak load, which would be 68 GW under MISO's current 5-year forward regional planning case. The revised cap allows for three exemptions, which have been narrowed from the original proposal, including requests to:

- Update provisional generation interconnection agreements with cost allocation ("restating");
- Convert projects from Energy Resource Interconnection Service (ERIS) to Network Resource Interconnection Service (NRIS) status; and
- Prioritize up to three requests from each regulatory authority[289] (city council for a municipal utility, governing board of a cooperative utility, or state public utility commission).[290]

MISO's proposal would accept projects in the order submitted (no scoring) and projects submitted after the cap is met would be used to replace projects withdrawn during the process of validating documentation and application payments. MISO is also evaluating a stakeholder-sponsored proposal for a volumetric price escalation of interconnection fees and penalties for interconnection customers that submit high levels of requests.

## 2.4. SPP's Consolidated Planning Process Cost Allocation Reform

SPP's consolidated planning process (CPP) is intended to merge various transmission-system upgrade studies — notably its Integrated Transmission Plan (ITP) and Definitive System Impact Studies (DSIS) — into a single common modeling platform. Under the CPP, interconnection customers would in essence buy in to a multi-value transmission upgrade plan.

The cost allocation reform enables the overall planning reform by providing interconnection customers with a more certain cost for network upgrades and reducing or eliminating restudies. For load responsible entities (e.g., utilities), SPP intends that the CPP will provide a more proactive approach to meeting future supply and demand needs.[291]

286 FERC ER24-341 Order, para 178-179.
287 FERC ER24-341 Order, para 180-182.
288 FERC ER24-341 Order, para 123-125.
289 Relevant Electric Retail Regulatory Authority (RERRA).
290 MISO, *Generator Interconnection Queue Improvements (PAC-2023-1)* (July 23, 2024), Interconnection Process Working Group (IPWG).
291 SPP, *SPP Visit to Kansas Legislature* (March 2024), p. 51.

SPP has introduced the concept of a CPP Entry Fee to provide cost certainty to developers.[292] Currently, SPP assigns specific network upgrade cost responsibilities to each interconnection customer based on each project's specific upgrade requirements, similar to Order No. 2023's guidance to establish a project-specific, actual incremental cost basis for cluster studies. If adopted, the CPP Entry Fee would instead simplify cost responsibility by assigning interconnection customers a fixed regional (or subregional) fee, based on a 20-year assessment of resource and transmission expansion needs.[293]

SPP is developing the CPP Entry Fee because it "has the potential to provide greater certainty for customers, speed up the process, and make it much easier to move to a consolidated planning process."[294] SPP views the CPP Entry Fee model as potentially better aligned with the beneficiary-pays principle than its current process because it "would spread the cost of facilities over multiple clusters of customers, more appropriately 'assigning' costs to beneficiaries."[295] This explicit linkage of investment to the need to serve both load and generator interconnections that will develop over time represents a departure from the participant funding model.

The CPP Entry Fee costs are allocated into three distinct types: regional, sub-regional, and direct assignment costs. Regional costs include costs to upgrade the extra-high voltage (EHV or >300 kV) system and one-third of costs for the high voltage system (HV) above 100 kV. Sub-regional costs include the remaining two-thirds of HV system costs and all costs for transmission below 100 kV (commonly referred to as SPP's "highway/byway" method).[296] Direct-assigned network upgrade costs are those resulting from each project's facilities study which determine the local upgrade costs.[297]

## 2.5. JTIQ: MISO/SPP Proactive Interregional Planning[298]

The Joint Targeted Interconnection Queue (JTIQ) is the most often cited transmission planning process focused on the seam between two Regions. The JTIQ process streamlines studies for interconnection requests that impact both the MISO and SPP regions by providing affected system study costs early in the process.[299] MISO and SPP anticipate filing the JTIQ framework in 2024.

The JTIQ process focuses on backbone projects addressing "larger/longer-term system needs" and allows for construction to begin before being fully subscribed in order to optimize network upgrades along the MISO/SPP seam.[300] Interconnection customers pay a JTIQ generator charge to subscribe to the JTIQ project benefits. Interconnection customers are also required to obtain

292 The CPP "Entry Fee" differs from other interconnection process uses of the term "entry fee." Often, the entry fee is understood to be the cost to enter the queue, also known as a study deposit, which partially covers the cost of interconnection studies. CPP's proposed entry fee covers the interconnection costs, including designing, engineering, constructing, and testing network upgrades.

293 SPP Entry Fee Framework, p. 19.

294 SPP Entry Fee Framework, p. 71.

295 SPP Entry Fee Framework, p. 74.

296 SPP Tariff, Attachment J, Section III.

297 SPP Entry Fee Framework, p. 23.

298 MISO Planning Advisory Committee, *MISO's Joint Targeted Interconnection Queue (JTIQ) Proposal* (April 24, 2024).

299 MISO Planning Advisory Committee, *JTIQ Status Update* (May 29, 2024), p. 5.

300 MISO Planning Advisory Committee, *JTIQ Presentation* (June 18, 2024), pp. 7-8.

individual, narrowly scoped studies to identify and receive cost responsibility for local network upgrades.[301]

While MISO and SPP maintain separate interconnection queues, the JTIQ framework coordinates the exchange of modeling data and conduct of impact studies. An important aspect of the JTIQ framework is a billing structure to improve administrative efficiency and rights to transmission congestion sought along these transmission pathways.[302]

## 2.6. New York Public Policy Transmission Planning Process

New York's Public Policy Transmission Planning Process involves the ISO, regulator, and stakeholders to determine an efficient plan to meet the state's public policies.[303] Stakeholders, including market participants and other interested parties, propose transmission needs driven by public policy requirements. The New York Public Service Commission reviews the proposals with input from NYISO and other stakeholders to identify the transmission needs that should be addressed.

NYISO is responsible for soliciting and selecting transmission projects. Project proposals may be submitted by developers or stakeholders. NYISO's evaluation considers the project's ability to meet public policy requirements, cost-effectiveness, and overall system benefits. NYISO assigns selected projects to entities for development and implementation.

## 2.7. Non-RTO/ISO Reforms

### *2.7.1. ERCOT Interconnection Cost Allowance*

Although not under FERC jurisdiction, ERCOT's connect and manage approach provides an important benchmark for other Regions due to its "straightforward and fast" interconnection study process.[304] Until recently, interconnection customers in ERCOT were assigned very low interconnection costs. ERCOT has limited projects' responsibility to certain direct costs of connecting the generator to the transmission system. The remaining costs have been paid by the transmission provider and passed through to retail customers.[305]

ERCOT is now adopting a policy that would assign cost responsibility above a standard allowance to interconnection customers. This significant reform was enacted in June 2023 by the Texas Legislature in House Bill 1500.[306] The new policy is intended to incentivize customers to minimize costs by siting generators close to existing transmission infrastructure.

301 *Id.*, pp. 8, 26, 31.

302 *Id.*, pp. 33-34.

303 NYISO, *OATT Attachment Y, Section 31 Public Policy Transmission Planning Process* (May 31, 2024).

304 "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 of curtailment to energy output and high basis risk to pricing hubs. … the biggest development risk driving withdrawal in ERCOT is anticipated congestion, and not the system upgrade costs resulting from the interconnection studies." Interconnection Scorecard, pp. 45-46.

305 16 TAC §25.195(c), as of 2023. In cases where costs are high, ERCOT's practice was to conduct 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).

306 Texas Legislature, *Act HB 1500* (June 2023), p. 8.

ERCOT ratepayers will continue to cover most interconnection costs up to a standard allowance, based on historical interconnection costs, potential consumer cost savings, and other relevant factors. The allowance covers costs required to interconnect generation directly with the ERCOT transmission system at transmission voltage. This includes constructing new substations or modifying existing substations if necessary for the interconnection. The Public Utility Commission of Texas set the allowance for interconnections at or below 138 kilovolts (kV) at $14 million and above 138 kV at $20 million.[307]

### *2.7.2. Bonneville Power Authority – Scalable Plan Blocks*

BPA's recently adopted cluster study process includes a method for segmenting its interconnection studies based on geographic location, reliability performance, or electrical relevance of similarly situated interconnection requests. In some cluster areas, BPA's study design will result in plans of service for subsets of interconnection requests, referred to as scalable plan blocks.[308]

BPA anticipates that developing plans for these groups of projects will allow for "a single plan of service for multiple projects, leading to fewer network upgrades and reduced costs."[309] Cost allocation of network upgrades within a cluster area or scalable plan block will be allocated using a proportional capacity method.[310]

### *2.7.3. Duke Energy's Red Zone Transmission Planning*

The North Carolina Utilities Commission released a Carbon Plan order to increase North Carolina's renewable energy integration in a cost-effective manner on December 30, 2022, as mandated by North Carolina House Bill 951.[311] The Commission directed Duke Energy to "take all reasonably necessary steps to construct fourteen projects in identified areas that needed interconnection upgrades, called Red Zone Energy Plans (RZEP)."[312] The results of the supplemental studies show that the completion of the 2022 RZEP projects will potentially allow the interconnection of approximately 3,759 MW of solar generating facilities in Duke's territory. Duke aims to complete 13 of the 14 RZEP projects by the end of 2026, with the final project scheduled for service in 2027.[313]

307 The Commission determined initial allowance amounts based on historical interconnection costs from 2019 to 2023. Allowances will be adjusted for inflation annually. Public Utility Commission of Texas, *Filing Submission, Docket No. 55566, Item 60*, p.1

308 BPA, *Reform for Large Generator Interconnection Queue: Frequently Asked Questions* (June 2024), p. 4. Henceforth, "BPA Reform FAQ."
BPA, *TC-25 Tariff Proceeding: Administrator's Final Record of Decision* (January 26, 2024), Appendix A: TC-25 Settlement Agreement, p. 37. Henceforth, "BPA TC-25 Decision."

309 BPA TC-25 Decision, p. P-1.

310 BPA Reform FAQ, p. 4.

311 NCUC, *Order Adopting Initial Carbon Plan and Providing Direction for Future Planning* (December 30, 2022), NCUC Docket E-100, Sub 179.

312 NCPTC, *2022 Report*, p. 27.

313 NCPTC, *2023 Collaborative Transmission Plan Midyear Update* (July 2023).

### *2.7.4. Duke Energy – Multi-Value Strategic Transmission (Carolinas)*

Duke Energy's two Carolinas affiliates are following a local transmission planning process based on the principles underlying FERC's proposal for regional transmission planning reforms, but separately approved by the Commission.[314] Duke Energy's Multi-Value Strategic Transmission (MVST) process illustrates the use of a semi-public process that allows for stakeholder participation in transmission study design.[315]

Decision-making regarding MVST studies is structured within the Carolinas Transmission Planning Collaborative (CTPC), which includes transmission planning experts and a stakeholder voting process to build consensus on the most plausible and data-supported scenarios.[316] Stakeholders are to have access to documented study process criteria, assumptions, and methods. The CTPC planning scenarios are intended to align transmission planning with resource planning, addressing grid changes like increased electrification and new compliance requirements.

A CTPC scenario-planning study is conducted at least triennially and considers:

1. Federal and state laws and regulations that affect the future resource mix and demand;
2. Federal and state laws and regulations that affect decarbonization and electrification;
3. Utility integrated resource plans approved pursuant to North Carolina or South Carolina statutes;
4. Trends in technology and fuel costs within and outside of the electricity supply industry, including shifts towards electrification of buildings and transportation;
5. Resource retirements and replacements or expiration of power purchase agreements;
6. Generator interconnection requests and withdrawals; and
7. Need for transmission during high-impact, low frequency events.[317]

314 FERC, *Order Accepting Filing* (March 12, 2024), Docket ER24-874.

315 Duke Energy, *A New Process for Multi-Value Strategic Transmission Projects, ER24-874*, para. 8, (March 12, 2024).

316 The CTPC is composed of the two Duke affiliates and other transmission owners. Committees and workgroups manage the CTPC process coordinate study development. Stakeholders participate in the CTPC process through the CTPC transmission advisory group.

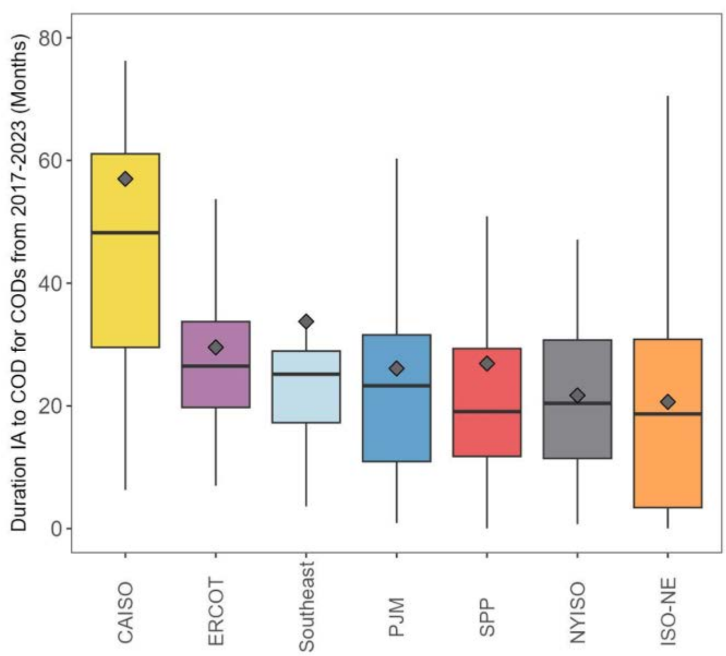
317 Duke Energy, *A New Process for Multi-Value Strategic Transmission Projects,* ER24-874, para. 8, (March 12, 2024).

# APPENDIX 3.

## REVIEW OF CONSTRUCTION PHASE DATA

Among regions that provide public data, CAISO has the longest timelines between the execution of an interconnection agreement and the commercial operation date of a new generator. As shown in Figure 7, the mean construction timeline in the CAISO region (indicated by the grey diamond) is about 58 months. Other regions and utilities included in the Berkeley Lab study have much shorter construction timelines, between 20 and 35 months. A key driver of this timeline is the construction of required network upgrades.

**FIGURE 7** | **Berkeley Lab Analysis of Construction Timelines[318]**




318 Queued Up 2024, p. 40. The report notes that, "Data were only available for 836 projects across 5 ISO/RTSs and one utility (Southern Company), out of 4,155 total "operational" project in the full dataset." Some data are not publicly available or require review of individual project reports.

In addition to the *Queued Up 2024* report from Berkeley Lab, this report provides analysis of transmission project databases from CAISO and two of its member utilities, SPP, ISO-NE PJM, and MISO, as well as additional analysis of PJM data supplied by Berkeley Lab.[319] These analyses provide new — albeit incomplete — insights into the factors that are associated with or driving the lengthy periods of time between interconnection agreements and commercial operation.

## 3.1. CAISO Region Transmission Construction Project Data

Berkeley Lab's finding that generators in the CAISO region have unusually long time periods between interconnection agreements and commercial operation is supported by analysis of transmission project construction timelines. There are several publicly available databases that provide different views of transmission projects in the CAISO region, including network upgrades directly associated with various generation interconnection agreements as well as other transmission projects that may also be intended to support new generation on the CAISO system.

Considering only CAISO-approved projects, as of January 2024 there were 59 ongoing projects with forecast completion dates averaging 6 ½ years in the future, according to data presented in the Transmission Development Forum (see Appendix 2.2). Although 28 projects have been completed and some remaining projects have been advanced, over the past two years those 59 projects have been delayed an average of 1 ½ years, an increase of about 30%.[320]

More detailed data regarding a larger number of transmission projects is available from Southern California Edison (SCE) and Pacific Gas & Electric (PG&E), the two largest investor-owned utilities and transmission owners in the CAISO region. These data are made available through stakeholder processes that were initially required on a temporary basis as a result of settlement agreements in FERC rate cases. In 2023, as discussed in Appendix 2.2, the California Public Utilities Commission (CPUC) directed utilities to continue to produce similar data in stakeholder process that will be collaboratively convened by the CPUC and the CAISO.[321]

### *3.1.1. Analysis of SCE Network Upgrade Schedule Data*

SCE data indicate that project durations from internal approval to (expected) in-service dates average about four years for pre-construction phase projects, and 5 ½ years for projects currently in construction.[322] For projects placed in service from 2012 to 2023, the average delay in in-service dates reported by SCE is about 1 ½ years. However, for projects currently in construction, the average delay in the expected in-service date is about three years.

319 NYISO makes interconnection queue data available here, but the available data are insufficient for the questions being studied in this report. For example, in-service project information does not include either the original proposed in-service date or the actual in-service date. Some of those data are available from the *Queued Up 2024* database; those data were insufficient to analyze for this report.

320 Analysis of Transmission Development Forum data (January 2022 to January 2024).

321 CPUC E-5252.

322 Analysis of Southern California Edison's Stakeholder Review Process (SRP) data. For projects with budgets over $10 million, project durations are longer. For example, projects with budgets over $100 million have average project durations of about 10 years. (December 1, 2023).

SCE claims that project delays are "typically project-specific and often due to external concerns, such as material delays, licensing/permitting delays, or [interconnection customer] delays."[323] However, our analysis of SCE's reported reasons for project comes to different conclusions, where project delays are defined as a change in the (expected) in-service date from the first-identified in-service date.[324]

- Execution-related issues are the most common reason given by SCE for a delay in an in-service date. Execution-related issues include coordination with other projects, outage constraints, resource constraints, and other issues that could be managed by SCE. For projects currently scheduled with in-service dates of 2023 or later, execution-related issues are associated with an average additional in-service date delay of over three years.
- Scope changes are the second most common reason given by SCE for a delay in an in-service date. However, projects with scope changes average less than a year delay to the in-service date. One possible explanation for this relatively small effect is that scope changes may often be strategies to avoid even longer delays.
- The largest effect on in-service delays and the third most common reason given by SCE for delay in an in-service date, is budget constraints. Phrases such as "budget plan," "priorities" or "resource restrictions" are interpreted as budget constraints. Considering past and future projects reported as being affected by budget constraints have in-service date delays of 2 ½ years — but budget-constrained projects with expected in-service dates of 2023 or later are facing delays of 4 ½ years.
- Interconnection customer requests or issues are just about as common as budget constraints but are only associated with average increases to project delays of just under two years.
- Tied for fifth-most-common are supply chain and permitting issues. Surprisingly, supply chain issues are associated with average in-service delays of less than a year. However, SCE almost always reports supply chain issues along with other drivers of schedule changes. In contrast, ongoing projects with reported permitting delays are facing average increases of three years to the construction schedule.
- Other causes of delay, including external events (such as weather or fire), consolidation of projects, or being placed on hold were not frequently cited by SCE.

### *3.1.2. Analysis of PG&E Network Upgrade and Generation Interconnection Project Schedule Data*

Data made available by Pacific Gas & Electric (PG&E) through its Stakeholder Transmission Asset Review (STAR) finds project durations from internal approval to (expected) in-service dates average almost eight years for pre-construction phase projects and 6 ½ years for projects currently in construction.[325] For projects placed in service from 2012 to 2023, the average delay

323 SCE LSSA Response, p. 12.

324 In many cases, SCE attributes project delay to multiple causes. The regression analysis weights all reported causes of a delay equally and separately, which may under- or over-state the contribution of individual causes to the delay. This effect may be more likely to result in understating the overall average delay attributable to a type of project delay cause, since it will often be the case that independent delays on the same project may overlap with each other. On the other hand, some delays may be dependent on others and thus worsen the overall average, such as outage scheduling that is complicated by supply chain or interconnection customer issues.

325 Analysis of Pacific Gas & Electric's Stakeholder Transmission Asset Review (STAR) data (December 1, 2023). For projects with budgets over $10 million, project durations are longer. For example, projects with budgets over $100 million have average project durations of about 12 years.

in in-service dates reported by PG&E is less than one year. However, for projects currently in construction, the average delay in the expected in-service date is almost three years.

PG&E has documented the effect of these delays on its generator interconnection portfolio, estimating that delays have affected "approximately 3.3 GWs of its nearly 11 GWs of generation projects."[326] In many cases, PG&E states that projects are impacted by both transmission upgrade project delays and customer-incurred delays. PG&E reported that the largest single driver of delays (affecting six projects representing 1.4 GWs) is reprioritization "to alleviate capital and financial availability constraints being experienced by PG&E and an enhanced focus on projects addressing safety over capacity pressures."[327] PG&E further explained that its decision deploy capital to wildfire risks was intended to manage "overall costs and customer affordability," and that about half of its available capital would be spent on risk reduction work. As that work is completed, PG&E intends to increase capital allocation to reliability, electric vehicles, decarbonization, and other state goals.[328]

PG&E attributes most of the rest of the delays to state or local permitting, supply chain, material modifications, missed clearance windows for work, and scope changes.[329]

Consistent with PG&E's report to its stakeholder review process, the largest reported cause of delays to project in-service dates is **budget constraints.**[330] Considering projects with in-service dates of 2023 or later, the impact of budget constraints on project averages about three years. However, for most projects with delays, PG&E does not provide a reason for the change in the in-service date. Those reasons that are provided include the following:

- Permitting is the second-most common reason for schedule delay, associated with about a 3 ½ year delay in in-service date.
- Scope change is the third-most common reason for delay in the in-service date, and by far the most impactful, on average adding more than five years to the in-service delay duration.
- Supply chain, interconnection customers, and external events are even less frequently reported as causes of delays in the in-service date. Of those, delays associated with interconnection customer issues are associated with an average of about three years of delay to the in-service date.

Among those transmission projects related to generation interconnection, PG&E does not prioritize projects based on any system-related metrics. For example, PG&E does not prioritize projects that would interconnect the highest capacity of new generation. Instead, those projects are sequenced "on a first-come, first-served basis with the requirement that to begin work, the parties must have an executed interconnection agreement and must have posted the

326 Yoxtheimer, D. *WRO Generator Interconnections (Stakeholder Requested Item #9), PG&E Stakeholder Transmission Asset Review Process* (August 1, 2023), p. 42. Henceforth, "Yoxtheimer."

327 Yoxtheimer, p. 44.

328 Pacific Gas & Electric. *Response to Large Scale Solar Association, January 25, 2023 CAISO Transmission Development Forum Stakeholder Comments* (January 25, 2023), p. 11-13. Henceforth, "PG&E LSSA Response."

329 Yoxtheimer, p. 46-47.

330 This finding is based on an analysis that is very similar to that conducted for SCE's SRP data. In many cases, PG&E attributes project delay to multiple causes. The regression analysis weights all reported causes of a delay equally and separately, which may under- or over-state the contribution of individual causes to the delay. This effect may be more likely to result in understating the overall average delay attributable to a type of project delay cause, since it will often be the case that independent delays on the same project may overlap with each other. On the other hand, some delays may be dependent on others and thus worsen the overall average, such as outage scheduling that is complicated by supply chain or interconnection customer issues.

appropriate financial securities."[331]

### *3.1.3. Comparison of SCE and PG&E Analyses*

Overall, the PG&E and SCE analyses demonstrate very similar trends. SCE's suggestion that "external concerns" drive most project delay is not demonstrated in either utility's reported causes of delay. Instead, both utilities' data demonstrate that execution-related issues and budget constraints are the most frequent and severe causes of delays to project in-service dates.

The three largest differences between PG&E and SCE appear to be (a) PG&E's relatively larger number of high-cost transmission projects (e.g., greater than $100 million), which tend to face longer delays, (b) PG&E's budget-based prioritization of safety projects over capacity projects, and (c) the high delay associated with scope changes for PG&E projects that is not observed in the SCE data.

## 3.2. ERCOT Data

ERCOT does not appear to make data on the construction phase for interconnection upgrades available to the public. ERCOT does provide an annual report on generator interconnection requests that includes details on the dates that generators were approved for energization and synchronization, so the data do provide a good indication of the length of time required for projects to be placed in-service. Unique to ERCOT's reporting is a listing of what types of environmental permits may be required. However, ERCOT's data do not identify the relevant transmission owner, required network upgrades, or upgrade costs.[332]

## 3.3. SPP Analysis

Berkeley Lab's finding that generators in the SPP region require about 2 ½ years (see Figure 7) between interconnection agreements and commercial operation is supported by analysis of transmission project construction timelines. For transmission projects *directly linked to generation interconnection* that received a Notice to Construct from SPP from 2018 to early 2024, the average construction period is (or is forecast to be) an average of about two years.

However, SPP's transmission project tracking report only identifies five such generation interconnection projects that have originated since 2018 out of 71 total transmission upgrade projects.[333] Because so few of SPP's transmission projects were designated for generation interconnection, the following analysis provides findings and observations regarding all transmission upgrade projects reported by SPP.[334]

---

331 PG&E LSSA Response, p. 10.

332 ERCOT, *June 2024 Generator Interconnection Status Report* (July 1, 2024).

333 SPP has been publishing transmission project tracking reports on a quarterly basis since 2010, and reports include active and completed transmission projects. Analysis of these reports was limited to those filed from 2018 through the first quarter of 2024 because most analyses were not sensitive to unique data reported before 2018. The resulting database included over 500 transmission projects with SPP Notice to Construct dated back to as early as 2007, although most notices were dated 2014 or later. SPP Quarterly Project Tracking Reports are here.

334 Some projects are excluded due to lack of data for the analysis in question. For example, key dates or cost data may not be included in the reports for particular projects.

Of 509 projects in SPP's tracking reports that had sufficient data for analysis, 430 have been placed in service. SPP's tracking reports appear to include only projects that require SPP approval, and thus would exclude many projects that might be included in the California project tracking discussed above.

SPP's transmission owners typically place projects in service about 2 ½ years after a Notice to Construct is issued.[335] Projects in the pre-construction phase are forecast to take about three years to place in service. However, 64 transmission projects that remain in the construction phase have been delayed an average of three years with resulting construction periods of about six years. Thus, even though about one-in-eight projects' construction periods are roughly doubled, the vast majority of transmission projects in SPP are constructed on schedule in about 2 ½ years.

Notably, project costs do not appear to vary much from the baseline across the project characteristics available in SPP's database. Regardless of project type, whether the transmission owner has many or few projects, or the date that SPP issued its Notice to Construct, SPP data indicate that final (or most current estimated) project costs tend to be fairly close to the baseline cost estimate.

SPP has a process for elevating review of projects with in-service date delays. According to SPP Business Practice 7060, for projects delayed by more than 90 days, the project is reviewed to determine if the delay is reasonable, whether some or all of the project could be changed to address the delay, or whether the project should be suspended for re-evaluation.[336] However, SPP's public reports do not provide much information regarding the reasons for delays in in-service dates.

Based on analysis of the available information from SPP, longer construction timelines in SPP are driven by three factors: high-cost projects (e.g., cost in excess of $100 million), project purpose, and transmission owner. The four high-cost projects reported by SPP (three in service, one in construction) averaged 5 ½ years to construct, but notably SPP did not report schedule delays and costs averaged only 8% over the baseline estimate.

The 11 projects classified as generation interconnection by SPP had the shortest average time to construct (about 16 months) and least average cost (about $3.3 million). However, generation interconnection projects experienced the largest cost overrun of about $1.2 million or about 62% above the baseline cost estimate.

Closely related to generation interconnection projects are the 16 transmission service projects, which are related to approved requests for long-term firm, point-to-point transmission service. These projects had the longest time to construct (about 52 months, on average without delay) and a relatively high cost of about $11 million.

The longest average construction delays in SPP are experienced by regional and zonal reliability projects (about half a year). Because these types of projects make up the vast majority of SPP's

335 For comparison with other regions, SPP's Notice to Construct may occur somewhat later in the pre-construction process than, for example, PG&E's internal approval. Construction timeline measurements used in this report are likely to have different meanings from region to region.
336 SPP, Q3 2024 In-Service Date Delay Report (July 16, 2024), Markets and Operations Policy Committee.

transmission projects, they tend to be fairly typical in terms of cost and time to construct.

The third factor that drives longer transmission timelines in SPP is the transmission owner. About three-quarters of SPP's reported transmission projects are owned by just six transmission owners. The average construction timelines of the other 25 transmission owners and four of the six largest transmission owners are all relatively close to the overall SPP average. However, two of the six largest transmission owners have significantly above-average construction timelines and delay periods.

- Nebraska Public Power District (NPPD) is reported to have 20 transmission projects, with an average time to construct of 54 months, including 21 months of delay. However, for the 2018-2024 time period, its seven projects averaged 34 months to construct (a bit below average) including 24 months of delay.
- Western Farmers Electric Cooperative (WFEC) is reported to have 61 transmission projects, with an average time to construct of 59 months, including 31 months of delay. WEFC's construction and delay periods remained close to its historical performance during the 2018-2024 time period.

NPPD and WEFC are non-profit generation and transmission (G&T) utilities that provide service to their member public power utilities. However, Basin Electric Power Cooperative is another non-profit G&T utility in SPP; for its 10 reported projects, average construction time and delays are well below the SPP average.

In summary, there are probably only two meaningful findings from the limited types of data included in the SPP report. First, that some utilities have better construction timelines than others — although why that is cannot be discerned from SPP's data. Second, that even though generation interconnection projects are expected to be quicker and lower cost than other types of projects, they experience the longest delays. This is consistent with interconnection customers' opinions that transmission owners may not give generation interconnection projects the highest priority or best project management attention, but does not provide conclusive evidence.

### 3.4. ISO-NE Analysis

Berkeley Lab's finding that generators in the ISO-NE region require a bit less than two years (see Figure 7) between interconnection agreements and commercial operation is more favorable than timelines for transmission upgrades. For transmission projects *directly linked to generation interconnection that were placed in-service from 2014 to 2023, the average construction period was about 3 ½ years.*[337]

ISO-NE's transmission project reports include 38 generation interconnection upgrade projects (with complete schedule data) placed in service between 2014 and 2023. Fifteen of those

337 ISO-NE's triannual transmission project tracking reports are available on a continuous basis back to October 2014. Most available data are included in the most recent report, but project in-service date forecasts were collected from prior reports. Project construction periods are dated from the earliest specified approval date (for some projects, there are multiple approval dates listed). The resulting database included about 1,000 transmission projects with approval dates dating back to 2003. ISO-NE's Regional System Plan Project List reports are available here.

projects are on the Eversource system and six are on the Central Maine Power system. However, ISO-NE's project reports do not include cost data for generation interconnection projects.

The project reports include about 400 approved "reliability upgrade" projects with complete data on schedule and cost and an additional 230 projects with complete data on schedule. ISO-NE's reports also include a number of projects that do not appear to require approval under either a market participant proposal review or a transmission cost allocation review, but those projects are excluded from this analysis because there is no identifiable start date for construction.

Beginning with projects approved in 2016, ISO-NE's construction period (forecast or actual) for all transmission upgrade projects increased from about 2 ½ years to about 3 years. This increase was mainly driven by projects that are currently under construction, as projects that have been placed in service maintained that 2 ½ year construction period.

Those ISO-NE projects that are responsible for the increased average construction period are primarily reliability upgrade projects and are characterized by large increases in cost and significant delays compared to the project schedule at the time of approval. Of these projects, several of the largest are being built by Eversource and National Grid. The other utilities with reliability upgrade projects under construction are generally building smaller projects, but those are also reported to have delayed in-service dates and higher costs than estimated at the time of project approval. The delays and cost increases reported by other utilities are not as substantial as those by Eversource and National Grid.

Otherwise, ISO-NE transmission upgrade projects have relatively consistent construction periods, project delays, and changes in cost. With the exception of the reliability upgrade projects discussed above, those metrics do not vary much based on the project type or the transmission system.

In summary, the limited types of data included in the ISO-NE report do not provide very significant findings. While some transmission system owners have better construction timelines than others, this is mainly attributable to several very large projects on just a handful of transmission systems. The relatively small share of projects that are classified as generation interconnection projects have construction schedules and delays that are similar to reliability upgrade projects.

### 3.5. MISO Data

The only construction phase data that appear to be available from MISO are its MISO Transmission Expansion Plan (MTEP) Appendix A Status Reports.[338] These annual status reports do not include all transmission upgrade projects being constructed by the transmission providers (including self-approved, customer-funded, etc.). The reports include the transmission owner, basic project identification, current cost, and expected in-service date.

338 MISO, *2022 MISO Transmission Expansion Plan (MTEP), Appendix A Status Report* (October 20, 2022).

MISO does collect and manage additional data, which are provided in quarterly project update reports. These pdf-format documents include more detailed information on the original in-service date and cost; current forecasted in-service date and cost; explanations of variance in schedule and cost; and regulatory status. We requested these quarterly project update reports in a format that did not require downloading individual documents and manually compiling the available data, but MISO staff indicated that their database does not currently have such export capability.

Considering the substantial effort that would be required to compile a useful summary of MISO's data, we elected not to complete that work. However, as shown in Figure 2, MISO appears to have the capability to analyze those data itself and was able to report that regulatory issues and supply chain issues are responsible for the vast majority of development delays of MISO projects. Given the response from MISO regarding its inability to export the data, it is not clear how MISO was able to compile the data shown in Figure 2.

### 3.6. PJM Analysis

Berkeley Lab's finding that generators in the PJM region require about 2 ½ years (see Figure 7) between interconnection agreements and commercial operation is supported by analysis of transmission project construction timelines. Prior to 2018, projects averaged 18 months to be placed in service. From 2018 to 2022, projects averaged 28 months to be placed into service.[339] Thus, recent trends indicate that the length of time to place a project with an interconnection agreement into service in the PJM region has increased by almost a year.

As shown in Table 4, this trend applies broadly to all resource types except storage and other resources.[340] Notably, wind resources take longer to place in service, while storage and hybrid resources take less time to place in service.

**TABLE 4** | **Average Months from Interconnection Agreement to Generator Placed In Service, PJM[341]**

| Resource Type | 2008-2012 | 2013-2017 | 2018-2022 | All Years |
|---|---|---|---|---|
| Natural Gas | 15.0 | 16.2 | 29.4 | **20.6** |
| Solar | 10.0 | 16.1 | 25.7 | **22.2** |
| Wind | 19.6 | 30.8 | 39.9 | **29.3** |
| Storage | n/a | 13.7 | 17.7 | **15.7** |
| Other (including hybrid) | 18.2 | 19.7 | 18.5 | **18.9** |
| **All Resources** | 16.5 | 19.0 | 28.1 | **22.5** |

339 Time to place into service is defined as the duration from "study date" to "actual in service date." Analysis of data from Joachim Seel et. al., *Generator Interconnection Costs to the Transmission System: Data for PJM Territory through 2022*, Lawrence Berkeley National Laboratory (January 2023). Henceforth, "LBNL PJM Data."

340 The trend in "other" resources is likely to be driven by changes in resource types. "Other" includes biomass, coal, hybrid, hydro, oil, and other generation types. In 2018-2022, only hybrid resources were interconnected, but no hybrid resources were interconnected prior to 2018.

341 LBNL PJM Data.

As of the end of 2022, there were 45 projects in the PJM region whose interconnection agreements were completed in 2019-2021, but not yet placed in service, representing 5,448 MW of nameplate capacity, as shown in Table 5. For context, there were about 659 projects under active study during the 2019-2022 time period. Even though the average period from an agreement to putting a generator in service is 22.5 months, 44% of projects that received interconnection agreements in 2019 (12 of 27) were still awaiting completion of network upgrades at the end of 2022.

**TABLE 5** | **In-Service Rate for PJM Projects with Completed Interconnection Agreements in 2019-2021**[342]

| | Number of Projects | | | | Nameplate Capacity (MW) | | | |
|---|---|---|---|---|---|---|---|---|
| | Interconnection Agreement | | | 2022 In-Service | Interconnection Agreement | | | 2022 In-Service |
| **Project Status** | **2019** | **2020** | **2021** | | **2019** | **2020** | **2021** | |
| In-Service Projects (Construction Completed) | 15 | 8 | 4 | 27 | 2,673 | 715 | 130 | 3,518 |
| Interim or Final Interconnection Agreement | 12 | 13 | 20 | 45 | 1,068 | 2,447 | 1,933 | 5,448 |
| Projects Without Interconnection Agreement | No Agreement in 2022 | | | 587 | No Agreement in 2022 | | | 49,595 |
| Total | N/A | | | 659 | N/A | | | 58,561 |

PJM does not provide information on the causes of lengthy construction periods or delayed in-service dates. However, PJM's data do provide some interesting findings.

- **Natural gas** generation progressed most quickly. Out of 13 gas-fueled generators active in the interconnection process during 2019-2022, three were placed in service and three others received interconnection agreements.
- Just four **storage**, **wind** or **other** generation facilities received interconnection agreements in the 2019-2022 time period, but three of those four were placed in service.
- Most generation in the interconnection queue is **solar**, with 21 projects being placed in service, 41 projects remaining in the construction process, and 377 projects still remaining in the interconnection study process.
- Even though they should require less complex network upgrades, there were few **energy-only** (ERIS) interconnection agreements. All three such projects were placed in-service during 2019-2022 with a total capacity of just 8 MW. The remaining 3,510 MW of project capacity placed in-service used the NRIS interconnection agreement, and the vast majority

342 PJM, *Project Status & Cost Allocation* data (accessed May 2024). The website notes that the database includes "baseline, network and supplemental projects in PJM's Regional Transmission Expansion Plan (RTEP)," as well as immediate-need reliability projects that are not approved through the regular RTEP proposal process.

of ERIS applications studied during this time period did not receive an interconnection agreement.

- Performance by transmission owner varied significantly. Dominion Energy performed the best – about half of the PJM projects and capacity placed in service during 2019-2022 was by Dominion, even though it held only about 1/5$^{th}$ of PJM's generation interconnection queue. Exelon, which had the fourth-largest share of the PJM queue, placed only 3 projects in service, representing 103 MW.

In contrast to the California data sources that provide considerable information about network upgrade schedule changes, it is difficult to identify causes or associations using the PJM data. On the other hand, PJM's data provide information about the capacity and resource type of generators that is lacking from the California and SPP data sources.

As with SPP, PJM's data do suggest that the transmission owner makes a difference. One interesting observation is that most PJM transmission owners with large interconnection queues mainly provide transmission and distribution service, with little or no direct role in owning generation. Standing out from this group is Dominion Energy, which is the only vertically integrated utility among the five PJM transmission owners with large shares of the PJM queue.[343]

343 The five largest shares of the PJM queue are located on the AEP, Dominion, FirstEnergy, Exelon, and PPL systems. Other PJM transmission owners host a little more than a tenth of the PJM queue.

# APPENDIX 4.

## FUTURE OPPORTUNITIES FOR MORE TIMELY CONSTRUCTION OF NETWORK UPGRADES

### 4.1. Outsourcing transmission upgrade construction.

An opportunity to reduce costs and lead times of construction of network upgrades is to open projects to competitive bidding by non-incumbent transmission developers. According to the Brattle Group, such processes have "yielded savings averaging 30% below the incumbent utility transmission costs."[344] A recent survey of the literature on outsourcing finds that it does not necessarily promote innovation, and that it is questionable whether it leads to more timely completion of transmission projects.[345]

Outsourcing appears to be most suitable for new facilities, such as new transmission lines or entirely new substations. For projects that involve upgrades to existing equipment or otherwise require a high degree of integration with existing transmission facilities, outsourcing may not be a good solution to the current problem.

One reason that outsourcing may not be a good solution is that it will probably not address supply chain constraints. As discussed in Section 4-B.2, advancing construction of some projects may delay construction of other projects. Outsourcing that is focused just on overcoming supply chain constraints may not be able to reduce transmission operators' construction timelines. In response to a proposal to allow interconnection customers to assist with procuring delayed equipment, Pacific Gas & Electric (PG&E) stated that "Ultimately, any assistance … would need to be from one of PG&E's approved equipment suppliers."[346]

344 Cal Advocates. *Comments on October 28, 2022 CAISO Stakeholder Call*, p. 3. Citing: Pfeifenberger, J. P., et al. *Cost Savings Offered by Competition in Electric Transmission Experience to Date and the Potential for Additional Customer Value* (April 2019), Brattle Group, prepared for LSP Transmission Holdings, LLC.

345 Benjamin Dierker, *Building New Critical Infrastructure: No Time to Waste* (July 2024), Alliance for Innovation and Infrastructure.

346 PG&E, *Response to EDF-Renewables*, CAISO Transmission Development Forum Stakeholder Comments (July 25, 2023), p. 5. See also: USGAO Transformer Study, p. 11.

Outsourcing could be used on a targeted basis to address capacity limitations affecting specific transmission owners. Some incumbent transmission owners may be slower to design, procure, and build new facilities than independent developers. Large developers with established, high-volume relationships with trusted manufacturers may be able to assist transmission operators with less established procurement relationships.

### *4.1.1. Enabling project developers to access greater competition for engineering, procurement, and construction services*

Under Order No. 845, FERC allows interconnection customers to build "high-side" POI direct connection infrastructure that is not owned or operated by the transmission owner. For interconnection customers who wish to select the option to build upgrades, certain transmission owners constrain them to a narrow approved vendor list. For example, two of the largest transmission owners in PJM have a very short list of engineering firms that are approved to provide full-service design, build, procurement, and construction of interconnection facilities.

- Exelon's transmission owner affiliates typically have just four or five approved engineering firms for work on substations or transmission equipment.[347]
- Dominion Energy has just four approved substation and transmission line engineering firms, and just one to three approved suppliers for almost every type of major substation and transmission line equipment.[348]

In contrast, American Electric Power (AEP) has twelve approved engineer, procure and construct (EPC) contractors on its approved vendor list and typically has one or two more approved suppliers than Dominion for comparable types of equipment.[349] One would expect that substantial cost premiums will be incurred when interconnection customers are prohibited from using certain market competitors by some transmission owners, which raises questions about whether the resulting costs are reasonable.

It may be reasonable for transmission owners to require use of contractors who are familiar with their construction practices and standards for equipment that is integrated into the overall transmission system, as the transmission owner is depending on the performance of the vendor. However, this requirement may not be as reasonable where the equipment's sole function is to deliver power from the generator to a dead-end structure at the 'high-side' utility substation that connects to but does not modify the existing transmission system. In such cases, it is the generator and not the transmission owners who is most dependent on the vendor's performance.

### *4.1.2. Outsourcing by transmission owners.*

Existing transmission owner procurement processes may make timely outsourcing of complete transmission upgrade projects difficult. The average time between need identification and selection of a winning bid as 433 days.[350] This additional activity would need to be considered

347 See, for example: Commonwealth Edison, *Approved Contractor List* (May 23, 2023) and *Approved Substation Contractor List* (April 27, 2023).
348 Dominion Energy, *Approved Service Providers and Equipment Suppliers* (April 16, 2024).
349 AEP Transmission, *AEP Approved Contractors and Major-Equipment Vendors* (May 17, 2024).
350 Benjamin Dierker, *Building New Critical Infrastructure: No Time to Waste* (July 2024), Alliance for Innovation and Infrastructure, p. 16.

when determining whether the net result would benefit construction timelines.

This issue was raised in response to advocacy for outsourcing by the California Public Advocates Office (Cal Advocates). In its initial response to Cal Advocates' proposal, PG&E expressed openness to "allow the market to construct needed upgrades while … PG&E retains ownership." However, it explained that a competitive solicitation process "can take at least one or more years," would need to take place before initial permitting and engineering activities, and would require close coordination to ensure system standards are met. PG&E also pointed out that many network upgrades are "brownfield projects," and it may not be possible for CAISO or FERC to "require a competitive process for work that may result in another entity owning or conducting projects on a transmission owner's existing assets and within its existing land owned in-fee or rights-of-way."[351] It appears that Cal Advocates did not pursue its request for more outsourcing after reviewing this response.

Where network upgrades are delayed due to capital constraints affecting the transmission owner, outsourcing is not a promising solution to that problem. In the case of PG&E and SCE, where prioritization and capital budget constraints are the top drivers of construction delay, the transmission owners would need to cede ownership on at least a temporary basis if they could not supply the capital needed to own the work. Temporary ownership of in-service transmission facilities by third parties seems like a very complex and time-consuming strategy to effectively accelerate construction timelines. Even if feasible, obtaining regulatory approval for a temporary ownership system would take more than a year and thus might not provide meaningful outcomes in terms of reductions to construction timelines.

### 4.2. Enabling more efficient construction practices by transmission owners.

Transmission owners' construction management practices significantly delay construction timeline estimates, resulting in longer and more uncertain construction schedules that impact project marketing and financing. For example, as discussed in Appendix 3.3, SPP data demonstrate that certain transmission owners average much longer times to construct and often have much larger delays relative to the original construction schedule. Interconnection customers have little recourse when such timelines increase significantly from during the study process to the execution of the interconnection agreement. And in California, execution-related issues are the most common reason given by SCE for a delay in an in-service date, where execution-related issues include coordination with other projects, outage constraints, resource constraints, and other issues that could be managed by SCE.

However, in neither case are these data sufficient to identify specific practices by the transmission owners that could be changed, with evidence of how much construction timelines could be sped up or increased in certainty through reform. The data are insufficient to demonstrate whether some transmission owners are more proficient at managing network upgrades as, perhaps, the poor performing systems may have older facilities that require unusually complex or extensive upgrades. Other factors not captured in existing datasets may

351 PG&E, *Response to American Clean Power - California, CAISO Transmission Development Forum Stakeholder Comments* (January 25, 2023), pp. 3, 5.

also be salient. Schedule performance may be affected by factors such as the transmission owner's willingness to adopt alternative technologies for network upgrades, co-location of resources at a single shared point of interconnection, or other improved construction management practices.

Interconnection customers observe that transmission owners do not appear to make effective use of scarce transmission construction crews by mobilizing them to complete multiple projects in a single area in the most efficient manner, which is critical given limited windows in which transmission owners are able to conduct outages. This is corroborated by one interview with staff of a transmission owner who indicated its practice was to complete network upgrades in the order requested, suggesting that there was no effort to optimize the scheduling of network upgrades to achieve cost and schedule efficiency. When a transmission owner conducts an outage to "fold in" a project line tap or energize a new substation serving a new interconnection customer, it could also plan to use that outage to complete construction or energize other substation work for neighboring projects, reducing costs and improving the schedule compared to the alternative — serial, returning visits.

### 4.3. Enabling more proactive interconnection facility design.

Another opportunity for improved efficiency is for transmission owners to study whether proactive design and construction of (1) proximate interconnection facilities and (2) open bays for future generator or load interconnections should be adopted. We understand that these practices are often implemented in ERCOT. Just as FERC endorsed proactive planning for system upgrades, and just as utilities routinely procure spare equipment to ensure more timely and efficient repairs to maintain reliability, they could also invest in additional interconnection points where they are aware, through information from the interconnection queue or other sources, that future interconnections are likely. This would be more efficient and advance the schedule for interconnections than the alternative – serial, separate mobilization of construction projects and additional maintenance outages at the substation.

### 4.4. Addressing constraints to expanding high-voltage equipment manufacturing capacity.

The US Department of Energy (DOE) has identified a number of constraints affecting the supply of high-voltage equipment, with a particular focus on the domestic supply chain.[352] As discussed in the beginning of Reform 4-B, there are just eleven domestic manufacturing facilities for large power transformers.

The recommendation to create a collaborative procurement program, discussed in Reform 4-B, is most focused on addressing DOE's finding that expansion of existing facilities and construction of new facilities appear to have been slow to respond to market demand due to concerns about a "bubble," the relatively high cost of capital, and a lack of confidence in a

352 USDOE Supply Chain Review.

long-term expansion of the market for high-voltage equipment.[353] According to experts in the procurement of high-voltage equipment and the development of new manufacturing facilities, senior executives of firms that manufacture such equipment have only recently demonstrated confidence that investments to substantially expand manufacturing in the US as well as in traditional global markets are warranted.[354]

DOE also identified limited manufacturing capacity for certain components of large power transformers as an underlying constraint.[355] Because of similarities in labor, material, and financial requirements between the component manufacturers and the transformer manufacturers, the challenges and solutions facing both types of manufacturers are likely to be similar. However, because the size and complexity of transformers are greater than that of transformer components and other high-voltage equipment such as circuit breakers, the corresponding difficulty of addressing each challenge is greatest for transformer manufacturing itself.

In addition to manufacturing capacity constraints, DOE identified two other key issues that are beyond the scope of this report. These issues relate to the supply of critical material inputs and labor.

With respect to critical material inputs, DOE has put a strong emphasis on the limited supply of grain-oriented electrical steel (GOES) and continuously transposed conduction copper (CTC copper), both of which are necessary for transformer manufacture.[356] There are both global and domestic limitations on supplies of these materials that constrain both distribution- and transmission-voltage transformer manufacturing capacity. Recent attention on the limited supply of GOES has been catalyzed by DOE's proposed regulations driving manufacturers of *distribution-voltage* transformers towards a newer, more specialized type of GOES. Experts interviewed for this report observed that they are not aware that raw material supply limitations currently constrain opportunities to increase production capacity for transmission-voltage transformers and other key equipment. However, DOE places particular emphasis on limited GOES supplies because its study found that domestic manufacturers are neither price-competitive nor able to meet the highest specifications required for large power transformer manufacture.[357]

With respect to labor, DOE and others report that domestic manufacturing capacity of high voltage equipment is limited by insufficient availability of employees with necessary skills as well as the ability to consistently comply with strict drug testing policies.[358] According to one expert interviewed for this report, this constraint may be geographic in nature. The opportunity for some existing manufacturing facilities to expand by constructing additional production lines may be constrained by the local labor force and challenges in attracting skilled labor to relocate to those locations.[359]

---

353 With respect to domestic US manufacturing, a related concern is dumping. USGAO Transformer Study, p. 12.

354 For example, large power transformers are not typically imported from China. These experts view the industry as very conservative with respect to considering imports from countries that do not have a proven track record with supplying highly reliable equipment.

355 USDOE Supply Chain Review, pp. 16-17, 21.

356 USDOE Supply Chain Review, pp. viii-ix, 15, 52

357 USDOE Supply Chain Review, pp. 47, 52

358 USDOE Supply Chain Review., p. 17. See also: USGAO Transformer Study, pp. 11-12.

359 It is unclear whether workforce limitations are being addressed by automation. At least one professional that assists with development of new manufacturing facilities understands that automation is helping to address workforce limitations. But a published interview with a transformer manufacturer indicates that robotics are not yet widely applied to transformer manufacturing. Alan Ross, *Interview with Prabhat Jain*, Power Transformer Technology Magazine (January 2022).

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.