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FERC Order 2023: Will it Unplug the Bottleneck?

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RC-2023-06 Commentary

FERC Order 2023: Will it Unplug the Bottleneck?

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Introduction

A central element of any plan to get to a zero-carbon economy in the United States involves electrifying the personal transportation fleet and shifting much of the building stock to electric heating, hot water, and cooking. This idea is based on the idea that the United States can shift electricity production from fossil fuels to zero-carbon sources, including solar and wind. While fossil-fuel generated electricity production has historically vastly outweighed production from wind and solar, that is changing. Electricity production from coal exceeded that from wind and utility-scale solar by over 158 terawatt hours per month on average between 2001 and 2010. Between 2011 and 2020, the production advantage of coal over wind and solar declined to under 88 terawatt hours per month and has declined further since 2020. Electricity production from wind and utility-scale solar exceeded that from coal for the first time in April 2022 as it also did during February through May 2023 ([EIA Electricity Data Browser]).

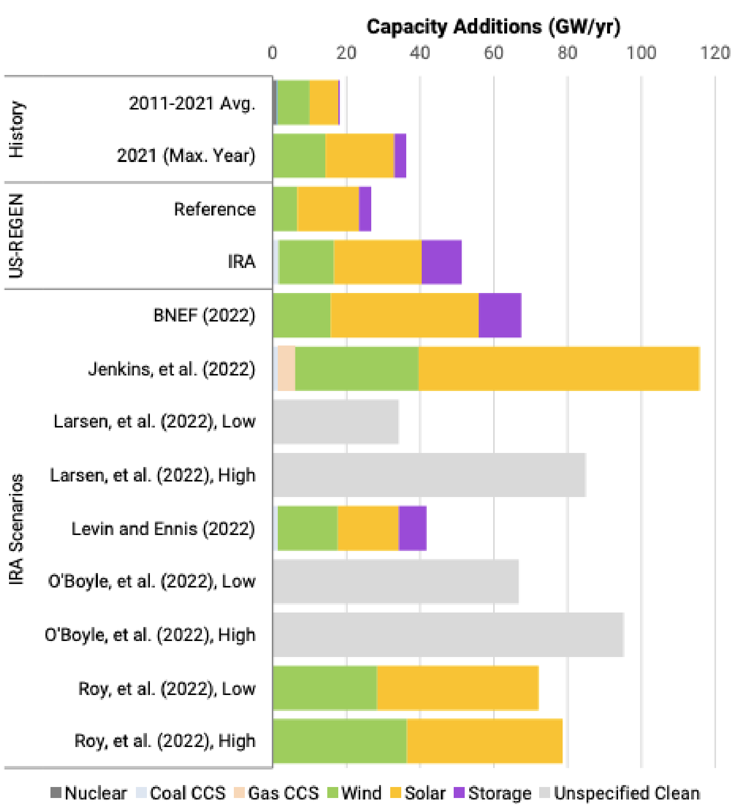

Figure 1. IRA Driven Capacity Addition Projections
Source: Bistline, Mehrota, and Wolfram (2023)

Greening the grid will require major new investments in wind and solar. Bistline, Mehrotra, and Wolfram (2023) estimate that average annual low-carbon capacity additions will increase from 27 GW per year to 51 GW per year due to the Inflation Reduction Act. Other studies, such as Jenkins et al. (2022) estimate additions will be even larger. (Figure 1). However, there is a significant waiting list for connecting new generation projects to the electrical grid. The number of applications has exploded since 2010, such that there are over 3000 projects in the various interconnection queues as of 2021 (Figure 2). Meanwhile, the median number of months to sign an interconnection agreement is nearly three years across all regions and projects, with significantly higher wait times in certain regions (e.g., MISO) and for certain fuels (e.g., solar and wind). The median time from interconnection request to commercial operation hit five years for projects completed in 2022, with wait times even longer for wind and solar, according to Rand et al. (2023).

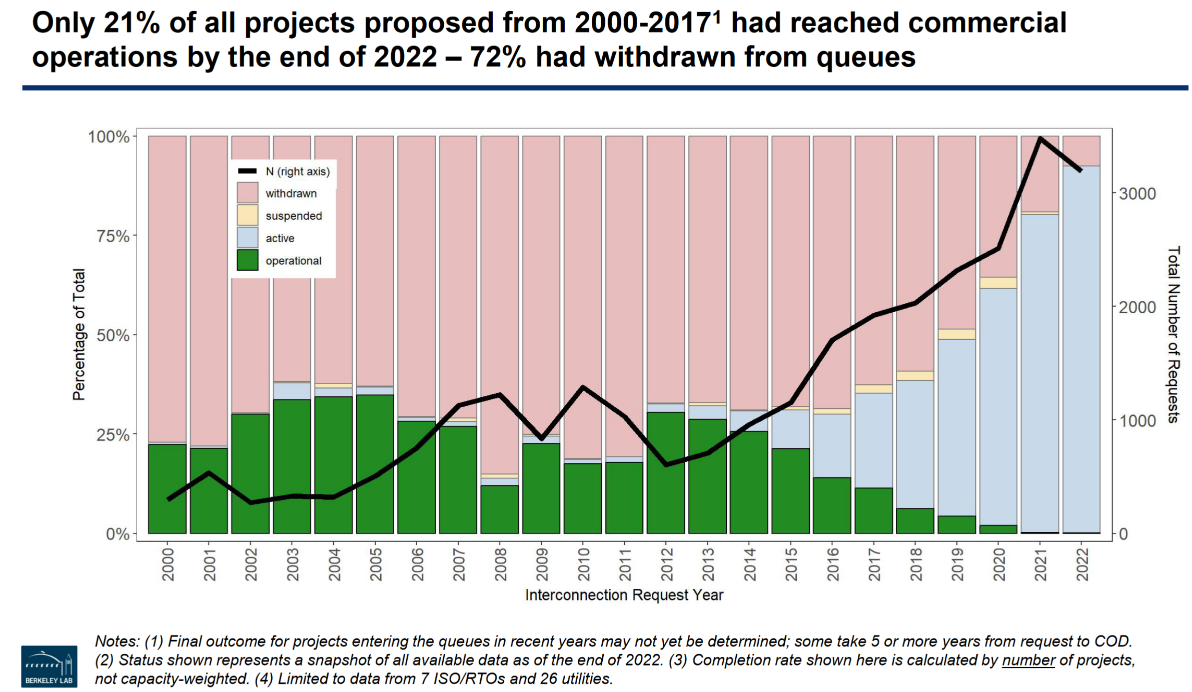

Figure 2. Interconnection Queue Status
Source: Rand, et al. (2023)

In response to this growing interconnection bottleneck, FERC released Order 2023, titled "Improvements to Generation Interconnection Procedures and Agreements," on July 28, 2023. The 1481-page order (including concurring opinions and appendices) sets out several changes to the interconnection process to reduce cost uncertainty and length of time in the queue. This policy brief explores the interconnection queue bottleneck and the various reasons for the bottleneck. It then examines FERC Order 2023 and asks whether it will make a meaningful difference in the interconnection queue bottleneck.

We conclude that FERC Order 2023 is a good first step towards addressing the problems that have arisen over the past two decades. It should reduce cost uncertainty to some extent and also reduce the number of speculative projects. Questions remain, however. Given the public good nature of interconnection and grid investments, how should the costs of network upgrades be shared among all grid users (on both the supply and demand side of the grid)? The current practice of shouldering all the costs on new generators connecting to the grid cannot be optimal. How can the interconnection process be made more of a forward-looking and proactive process that starts from a premise of achieving certain long-run goals of stability, reliability, while moving the United States on a path to a zero-carbon grid? Related to that question is the question of how best to link transmission planning with the process of connecting new projects to the grid?

II. Background

In 2003, FERC issued the initial interconnection policy, Order 2003, establishing procedures for connecting large generation facilities (200 MW and larger) to the transmission grid. The purpose of the order was to standardize the interconnection process, reduce planning uncertainty, and reduce delays for new projects. It was also designed to level the playing field between vertically integrated firms and merchant projects.

Due to transmission grid congestion, the introduction of a new generating facility to the grid can have unforeseen consequences for existing generators on the grid, depending on load characteristics. As a result, transmission providers require a series of studies before allowing a new facility to interconnect to the grid to ensure stability.[1] FERC Order 2003 assigned all costs of network upgrades arising from the proposed project to the first project that triggered required network upgrades. The required upgrades and consequent costs were based on both the existing transmission grid and set of grid-connected facilities as well as on the anticipated grid-connected facilities earlier in the queue than the current project. Upstream departures from the queue could trigger changes to the assigned network upgrade costs, changes that could go up or down. As projects proceed through the various study processes (Feasibility, System Impact, and Facilities Studies), costs can dramatically change.

A complicating factor for predicting the ultimate network upgrade costs that will be borne by a particular project is the incentives due to the "first-come, first-served" nature of Order 2003 for submitting similar projects with different locations and/or queue submission dates. Modest changes in location or position in the queue can lead to significant changes in the assigned network upgrade costs that are difficult to predict for developers, given the obscure nature of these studies. Entering multiple projects in the queue, even when the developer only plans to construct one project, creates option value as the project with the lowest assigned costs can be kept while others are eventually withdrawn from the queue at low cost. This has been long understood (see, e.g., Gergen et al., 2008). Queue squatting with ghost projects is a way to insure against unexpectedly high network upgrade costs but leads to longer queues and greater uncertainty for all other projects around their ultimate assigned costs.[2]

The first-come, first-served approach with generators paying most (if not all) network upgrade costs has been especially problematic for renewable projects, which, among other things, are more geographically constrained than fossil fuel projects. See, for example, the analysis by Alagappan et al. (2011) that compares 14 markets in the United States, Canada, and Europe. Analysis by Lawrence Berkeley Labs finds that the average time from interconnection request to commercial operation tends to be the longest for solar and wind projects (Rand et al., 2023, slide 32).

Johnston et al. (2023) do a detailed analysis of data from PJM. They find that interconnection costs, on average, are higher for renewable projects. They also identify important externalities across projects. As the queue size increases, study times increase. This is a classic negative congestion externality leading to too much entry. Second, interconnection costs tend to be lower when locating near projects that recently connected and incurred network upgrade costs. This suggests a positive timing externality as later entrants draft behind earlier entrants.

The existing literature indicates clear problems with queuing from the first-come, first-served approach taken by FERC Order 2003, along with the approach of allocating all network upgrade costs to the specific project triggering upgrades.

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[1] Transmission providers can be Regional Transmission Operators (RTOs), Independent System Operators (ISOs), or regional or state vertically integrated utilities.

[2] "[S]peculative projects in overcrowded first-come, first-served queues result in an inefficient allocation of queue positions and processing priority, which imposes timing and cost uncertainties on projects in the queue, particularly those with lower positions" (Gergen et al., 2008, p. 9).

The latter is particularly problematic since added upgrade costs to the project have risen from under 10 percent typically to as much as 50 to 100 percent of project costs, according to a report from the Americans for a Clean Energy Grid (2021). The ACEG also argues that network upgrades contribute to a more resilient grid, so placing all these costs on an interconnecting generator violates FERC's "beneficiary pays" principle (ACEG, 2021, p. 12).

FERC has recognized that network upgrade cost uncertainty creates perverse incentives for project developers. FERC writes, "We find that, absent reforms to require transmission providers to provide additional interconnection information, which can be used by interconnection customers prior to submitting an interconnection request, speculative interconnection requests will likely remain at current levels and continue to contribute to interconnection study delays and add costs to the interconnection process." (FERC Order 2023, para 67). The piecemeal response to the deficiencies of FERC Order 2003 has long led to calls for a response from FERC. FERC Order 2023 is that response.

III. FERC Order 2023

In response to the various problems identified with the interconnection process under FERC Order 2003, FERC released Order 2023 in July 2023. Citing significant changes in the electricity sector since FERC Orders 2003 and 2006, FERC noted that:

> The growth of new resources seeking to interconnect to the transmission system and the differing characteristics of those resources have created new challenges for the generator interconnection process. These new challenges are creating large interconnection queue backlogs and uncertainty regarding the cost and timing of interconnecting to the transmission system, increasing costs for consumers. Backlogs in the generator interconnection process, in turn, can create reliability issues as needed new generating facilities are unable to come online in an efficient and timely manner.
>
> FERC Order 2023, Paragraph 3

While there are numerous elements in the nearly 1500-page order, reforms fall into three broad categories:[3]

1. Reforms to implement a first-ready, first-served cluster study process;
2. Reforms to increase the speed of interconnection queue processing; and
3. Reforms to incorporate technological advancements into the interconnection process.

Many of these reforms take best practices from the more forward-thinking and proactive ISO/RTOs such as MISO, CAISO, and ERCOT, which are rich in wind and solar resources and were therefore incentivized to innovate in their interconnection approach sooner. They, too, however, are still encountering varying degrees of challenges in managing their queues.

[3] There are a host of other more minor issues addressed in the order and not discussed here.

A. *First-Ready, First-Served Cluster Study*

FERC Order 2023 calls for interconnection procedures to adopt cluster studies as the default method of studying interconnection costs. By clustering applications within specific windows (FERC set a 45-calendar day window during which requests could be made), all applications within that window would be treated as having been received at the same time. The cluster approach, FERC argued, "will minimize delays that arise from proposed generating facility interdependencies under the existing serial study process, in which lower-queued interconnection customers can strategically and monetarily benefit from network upgrades and associated costs borne earlier in the interconnection process by higher-queued interconnection customers." (para. 177) FERC left open how transmission providers create clusters. The order also included a number of proposals that would reduce the number of restudies and reduce cost uncertainty for applicants. It also included a requirement that transmission providers post metrics for cluster study processing time. Presumably, doing so will encourage the timely processing of the cluster studies.

Although a meaningful improvement, cluster studies still do not tackle significant issues that arise in the study process. CAISO, for example, implemented the cluster approach in the mid-2000s but still struggles with consequential queue backlogs. In 2021, CAISO received three times the amount of typical requests in what was then dubbed a "super-cluster." The lack of transparency in the study process still incentivizes developers to submit multiple projects without a clear understanding of what the ultimate upgrade costs will be. When the studies' results are returned, and the upgrade costs are too high for developers, they drop out, leading to a massive exodus of projects from the study and rendering the original cluster study of little use, necessitating a re-study. This, in turn, leads to longer queues, more costly studies, and an overall clogging of the queue.

In an attempt to address the transparency issue, FERC took note of one of MISO's successful policies to improve information access. As part of the cluster study process, the order requires transmission providers to provide "heatmaps," supplying information about impacts at the node-level of existing and queued generation impacts that can be useful to prospective interconnection customers in subsequent applications. The heatmap would help prospective developers identify available interconnection capacity and points of congestion at particular sites that would likely trigger network upgrades or possible curtailments from potential future generators. This would help prospective developers avoid congested sites, although upgrades to the transmission system would eventually become inevitable.

With the requirement for a cluster approach comes a need to allocate network upgrade costs within the cluster. The FERC order allocates them on a "proportional impact method," which, according to the order, means "a technical analysis conducted by Transmission Provider to determine the degree to which each Generating Facility in the Cluster Study contributes to the need for a specific System Network Upgrade" (footnote 914). This should hopefully ameliorate the issue of ghost projects, giving a greater sense of what the queues look like and allowing for more effective policy in the future.

FERC is also increasing the pressure on speculative project submissions from developers. Upon entry into a cluster, prospective generating facilities now must make an initial study deposit between $55,000 and $250,000 (depending on the size of project). They must also meet stringent site control requirements, "thereby reducing the negative impacts of speculative interconnection requests" (para. 583).

In addition, a further effort to address speculative projects and to reflect the negative externalities imposed on other projects in a cluster when a project withdraws from the queue, the order imposes withdrawal penalties that increase the further along in the study process the project is. Withdrawals at the initial cluster study incur a penalty of twice the study costs. If withdrawal occurs further along, the penalty rises to as much as 20 percent of network upgrade costs. Penalties are not imposed if the withdrawal does not have a material impact on costs or timing on projects with an equal or lower queue position. Nor are penalties imposed if there are significant, unanticipated increases in network upgrade cost estimates during the study process.

B. Increase the Speed of Interconnection Queue Processing

The order made two substantive changes to cut down on the time projects spend in the interconnection queue. First, it eliminated the "reasonable efforts" standard for carrying out the various interconnection studies and, at the same time, created financial penalties on transmission providers for failing to meet requisite interconnection study deadlines. This recognizes the fact that transmission providers historically had been missing deadlines for completing studies while facing no consequences for doing so. Penalties for delayed studies now range from $1,000 per day for cluster studies to $2,500 per day for facilities studies beyond tariff-specified deadlines (in all cases subject to overall caps on penalties).

Second, it standardized the study process for affected systems. Noting that the current LGIP "lacks consistency between transmission providers" (para. 1026), the order set forth a series of requirements, including study scope, timelines, and penalties for failure to meet deadlines. The standardization will allow for greater transparency and information and resource sharing between RTOs/ISOs.

C. Incorporate Technological Advancements Into the Interconnection Process

The third set of issues involved were measures to incorporate technological advancements that create some flexibility in the interconnection process. First, it allowed multiple generating facilities to co-locate on a shared site behind a single interconnection request, thereby addressing what FERC perceived to be a potential barrier to entry by "necessitat[ing] a case-by-case approach that the Commission cautioned against in Order No. 2003" for co-located facilities.[4] FERC argued in the final order that the adding greater clarity around co-location would facilitate greater competition. The Commission argued that this reform would "create a minimum standard that would remove barriers for co-located resources by creating a standardized procedure for these types of configurations to enable them to access the transmission system" (para. 1325).

Next, it required transmission providers to evaluate requests to add generating facilities to an existing interconnection request prior to deeming the addition a material modification so long as the request is done in a timely fashion and does not affect the requested interconnection service level. Material modifications involve significant additional costs to a generating facility, so this removes unnecessary costs when the request is unlikely to affect network upgrade costs.

Additional changes under the order provide various degrees of flexibility, including the ability to access surplus interconnection service of existing customers and use assumptions in studies that reflect the proposed charging behavior of storage resources. This might, for example, cover requirements about charging behavior during peak load conditions.

IV. Assessment of the Order

The shifts to cluster studies and a first-come, first-ready approach are impactful and should serve to reduce the number of speculative projects that contribute to clogging the interconnection queue. More substantial withdrawal penalties will also help. It should be noted once again that many of the reforms included in FERC Order 2023 have already been put into

[4] Notice of Proposed Rule Making, 179 FERC ¶ 61,194 at Par. 239.

effect by a number of transmission providers, including cluster study reforms, changes to first-come, first-served, cluster study cost allocation, and enhanced financial or readiness commitments. Cluster studies, for example, are already required in a number of RTOs/ISOs, including CAISO, NYISO, and MISO, among others (Bartlett et al., 2023). Queue data from the Lawrence Berkeley National Laboratory does not show that waiting time in the interconnection queue has fallen significantly (or even appreciably) with these reforms.

But there are other unaddressed problems. The first is that network upgrades resulting from new generation facilities added to the grid add to the resiliency and flexibility of the grid. Given that, having the generation facilities that prompt the network upgrades pay the entire cost of upgrades violates FERC's "beneficiary pays" principle and likely leads to too little investment. Socializing some of these costs to all transmission grid users is a policy meriting greater consideration and is likely to be an important incentive for adding new zero-carbon generation to the grid and so contribute to national plans to green the electrical grid dramatically.

The second relates to one of the core issues with the current interconnection paradigm: These procedures were created during and for an era dominated by fairly location agnostic and dispatchable fossil fuels. All the rules and regulations were created in consideration of the physical attributes of these generators, which are noticeably distinct when compared to geographically constrained renewable generator projects. Nothing in the order moves us closer to a fully forward-looking, rational grid planning process where we consider from a system-wide perspective where new generation should be sited and what additions to the transmission grid will support new renewable generation that is clogging up the queue.

Examples of these more forward-looking approaches can be observed in Texas and Europe. In Texas, the Legislature established the Competitive Renewable Energy Zones (CREZ) in 2005, which established priority areas for utility-scale wind development in the North-Western Permian Basin. The legislation included transmission planning and construction where the costs were socialized by ratepayers. The policy successfully resulted in 3,600 miles of high-voltage transmission lines, comprising 23% of US additions in the past 12 years. It also facilitated 23 GW of wind generation, which is 56% of the state's total wind capacity, the highest in the nation (Jankovska & Cohn, 2020). In Europe, central planners identify high renewable resource regions, for example in the North Sea, and plan the transmission corridors as well as the interconnection processes. Once the planning is complete, RFPs are released to allow biddings from developers to compete on project proposals. This approach has led to a boom in offshore wind capacity.

In contrast, in the US as it is, we leave it to developers to decide where and when to site new projects and determine network upgrades without considering how changes to the transmission grid could be implemented to rationalize those grid additions. This piece-meal approach severely constrains our current strategy to reduce our emissions through electrifying transportation and the building sector with the hope that we will have a zero-carbon electricity system to power those sectors. In order to unlock the energy transition, more comprehensive reforms that enable a more centralized planning approach are needed.

As the ACEG (2021) has put it,

> FERC and RTOs should pursue planning reforms. Consumers would benefit from more efficient transmission at a scale that brings down the total delivered cost, rather than continuing the current cycle of incremental transmission built in the project-by-project or generator-only cost assignment regime. That shift will not happen in the current interconnection process. Instead, FERC should fundamentally reform the regional and inter-regional transmission planning process to require broader pro-active and multi-purpose transmission planning. (p. 6)

FERC Commissioner Allison Clements puts it even more dramatically in her concurrence with the 2023 order:

> [W]hile this rule can be expected to improve matters, more will be necessary to solve the problem. What was perhaps considered a straightforward kitchen renovation has become more complicated. After we have removed the cabinets and taken out the drywall, we have discovered outdated wires, rusted pipes and cracks in the foundation. None of these additional challenges are insurmountable, but they are in some ways more fundamental to getting that modern, working kitchen up and running. Clements (2023), p. 3

She argues for further work that links the interconnection process to proactive transmission planning. She cites promising developments in SPP, MISO, and CAISO. However, those initiatives are in the early stages, and there is a lack of comprehensive and nationally cohesive planning of a sort that FERC could lead on.

Second, she sees potential promise in a system that links interconnection processes with competitive resource solicitations, with the latter ensuring scarce interconnections are allocated in an efficient manner. Finally, she argues for the consideration of a more "focused" interconnection approach that limits restudies. While this is not a panacea and raises important questions, streamlining the process and reducing restudies (and consequent cost changes) seems valuable. Her suggestion is echoed in a report by Norris (2023), who advocates for a focused approach ala Clements or a connect and manage approach as is carried out by ERCOT and in the UK. Key to this approach is a greater willingness to utilize curtailments in an energy-only market to manage the grid rather than an exhaustive interconnection study process that tries to avoid grid congestion issues where curtailment might be necessary. As Norris puts it, "The overall trade-off for generators is the ability to interconnect much more quickly with fewer network upgrades in exchange for bearing more curtailment risk and not receiving capacity compensation." (p. 4) Whether this is a trade-off that generators and grid customers would tolerate outside of Texas is unclear.

While our focus is specifically on FERC Order 2023, it is clear that a more efficient and streamlined interconnection process and build-out of the national transmission grid will require coordination among government regulators, transmission providers, interconnection customers, and the research community to develop and implement improved data collection, modeling, and interconnection procedures, as well as workforce development to ensure there are sufficient numbers of trained engineers with policy expertise required to address interconnection demands.[5]

The order also does not address how it will tie into other FERC Orders, like Order 2222 which incorporates distributed energy resources (DERs) into the wholesale markets. Order 2222 has yet to be fully implemented by transmission providers as most are struggling to incorporate the proper technology and transparency required of the order. However, it is important to note that the full implementation of this order could potentially lessen the strain on the transmission system. Coupling these orders together would help in the technology development process to make technology that can address the needs of both orders at the same time, making technology that can actually work together. Not only that but coordinating both orders more tactfully together could allow for a greater understanding of what the grid will look like in 10 years' time. The interconnection queue with DERs and a cleaner queue will lead to new needs and policies that will need to be written. Not incorporating these policies together with future-focused measures will require more work in the near term.

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[5] The Department of Energy has convened the Interconnection Innovation e-Xchange (i2X) to engage in stakeholder engagement to identify key needs to streamline grid planning and the interconnection process. They are working on a "roadmap" of suggestions in the short and long run.

V. Summary

The long delays in the various ISO and RTO interconnection queues stand as a significant impediment to the transformation of the US electrical system to a zero-carbon grid. The process established over twenty years ago was designed for a fossil-fuel generation fleet that was locationally flexible. Wind and solar projects are more geographically constrained and the interconnection process is not well-designed to integrate these constrained resources into the grid. At the same time, the cost allocation process established in FERC Order 2003 contributes to significant cost uncertainty, which has led to gaming the system through the use of multiple speculative projects in an effort to minimize network cost upgrades assigned to developers by transmission providers. This, in turn, contributes to further clogging the queue and adding to delays and costs.

FERC Order 2023 is a good first step towards addressing the problems that have arisen over the past two decades. It should reduce cost uncertainty to some extent and also reduce the number of speculative projects. Questions remain, however. Given the public good nature of interconnection and grid investments, how should the costs of network upgrades be shared among all grid users (on both the supply and demand side of the grid)? The current practice of shouldering all the costs on new generators connecting to the grid cannot be optimal. How can the interconnection process be made more of a forward-looking and proactive process that starts from a premise of achieving certain long-run goals of stability and reliability, while moving the United States on a path to a zero-carbon grid? Related to that question is the question of how best to link transmission planning with the process of connecting new projects to the grid?

Historically, FERC has taken a siloed approach in its orders with little coordination between transmission planning and the interconnection process. We can only hope that FERC takes up the challenge put forward by Commissioner Clements in her concurrence with FERC Order 2023 to take a more coordinated and comprehensive approach to planning to address the challenges we face as we modernize and decarbonize our electrical system.

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