ARTICLES

# LOST IN TRANSMISSION: HOW TO BRING MORE CLEAN ENERGY ONTO THE GRID

by Ryan Block

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## SUMMARY

**The Inflation Reduction Act and other policies are pushing solar, wind, and other clean energy technologies into the marketplace. But these generators struggle to make the physical connection to the electricity market because interconnection is proving to be a bottleneck; over 2,000 gigawatts of capacity are waiting to connect to the grid. This Article examines the Federal Energy Regulatory Commission's (FERC's) regulations that govern the entry of new generation resources onto the grid. It reviews the statutory underpinnings of FERC's interconnection authority and analyzes key federal regulations, including pending FERC proposals, and finds that current backlogs are the product of outdated assumptions, perverse incentives, and unintended consequences, which in turn cause externalities and uncertainties. It concludes by proposing policies to enable the development and deployment of grid-enhancing technology.**

In 2021, more than 1,400 gigawatts (GW) of generation and storage capacity across the country sat in so-called interconnection queues, waiting to connect to the electricity grid so they could bring their output to market.[1] In 2022, that figure increased to more than 2,000 GW. Of the 2,000 GW of capacity in the interconnection queues, 1,350 GW is generation capacity and 680 GW is storage. In addition, 1,260 GW are zero-carbon projects.[2] To put the 2,000 GW of capacity figure in perspective, this capacity represents more than 10,000 projects,[3] and this capacity would be sufficient to power approximately 484 million homes.[4]

This Article explores the federal regulations and institutions pertaining to grid interconnection. The term "interconnection" describes the rules, procedures, technological attributes, and equipment "required to connect generators or other resources (such as energy storage devices) to the transmission system," so that these resources can partici-

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1. *Record Amounts of Zero-Carbon Electricity Generation and Storage Now Seeking Grid Interconnection*, Lawrence Berkeley Nat'l Lab'y (Apr. 13, 2022), https://emp.lbl.gov/news/record-amounts-zero-carbon-electricity.
2. Joseph Rand et al., Lawrence Berkeley National Laboratory, Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection as of the End of 2022, at 3 (2023), https://emp.lbl.gov/sites/default/files/queued_up_2022_04-06-2023.pdf.
3. *Id.*
4. There are 142,153,010 homes in the United States as of July 1, 2021, and the average home uses 10,632 kilowatt hours (kWh) per year. *See* U.S. Census Bureau, *QuickFacts: United States*, https://www.census.gov/quickfacts/fact/table/US/VET605220 (last visited July 10, 2023); *see also* U.S. Energy Information Administration, *Frequently Asked Questions (FAQs):How Much Electricity Does an American Home Use?*, https://www.eia.gov/tools/faqs/faq.php?id=97&t=3 (last updated Oct. 12, 2022). These numbers were used to calculate the number of homes that 2,000 GW of capacity could power.

Let us assume a capacity factor of 29.4%. This value represents the average capacity factor for wind energy and solar energy. In 2021, the average capacity factor for wind energy in the United States was 34.4%, and the average capacity factor for solar photovoltaic energy in the United States was 24.4%. *See* U.S. Energy Information Administration, *Electric Power Monthly: Table 6.07.B. Capacity Factors for Utility Scale Generators Primarily Using Non-Fossil Fuels*, https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_6_07_b (last visited July 10, 2023).

pate in a wholesale electricity market.[5] While the electricity industry can be divided into generation, transmission, and distribution sectors, the point of interconnection blends the generation sector with the transmission sector of the energy industry, with ramifications for grid reliability, consumer demands on the fuel mix, and market competition.[6]

On average, projects built between 2011 and 2021 sit in the interconnection queue for 3.7 years, almost equivalent to an entire presidential term, sometimes exceeding this duration.[7] In fact, the median wait time is "[five] years for projects built in 2022."[8] Time is indeed money for energy project developers, who often rely on debt financing that requires regular interest payments. These projects are mostly solar, wind, and battery storage projects[9] that lose economic value as they wait for interconnection, with delays adding to the capital expenditures.

The composition of the U.S. Congress and agency heads changes every two years with elections and resignations. Along the way, a significant number of policies, regulations, and laws change, which means that project developers may completely miss out on opportunities to take advantage of federal and state incentives that originally attracted them to a specific project. The resulting risk of policy change may further adversely impact their ability to plan and obtain financing.

The inability to transmit electricity serves as a barrier to entry in wholesale and retail markets, as only 21% of projects in the interconnection queue between 2000 and 2017 reached commercial operations by the end of 2022.[10] On the other hand, the withdrawal rate is 72%.[11] While there are other reasons that developers may cancel their projects, the trend suggests that interconnection serves as an obstacle. However, more empirical research is needed to determine the proportion of uncompleted projects where the developers listed interconnection issues as part of the reason to cancel the project.

As clean energy generators wait for grid connection, their economic and low-carbon benefits are delayed, if not lost due to project cancellation. In 2019, the Federal Energy Regulatory Commission's (FERC's) former chairman, Richard Glick, and general counsel, Matthew Christiansen, concluded that a "wholesale reinterpretation of the Commission's jurisdiction" is not necessary to combat climate change; instead, they found that the issue "increase[s] the stakes associated with the Commission's exercise of its existing authority."[12] If we are to reach our decarbonization goals by 2050, our nation will need to triple the size of current transmission systems.[13] So the stakes of transmission system development increase dramatically when we consider the reliability and resiliency, renewable integration, and national security benefits, as well as the current societal risks from a lack of development.[14]

The transmission sector is highly capital-intensive, requiring between $1.5 and $5.7 million per mile built for a single circuit transmission line in 2022,[15] but cost estimates vary widely by the specific project, location, region, and size. The cost of transmission infrastructure is very complex with many inputs, but generally, the cost estimates account for the cost of (1) easements and rights-of-way; (2) site work; (3) the materials for and installation of the different types of structures and foundations; (4) the various components of conductors, optical ground wires, shieldwires, converters, and substations; and (5) the professional services and overhead to develop the projects.[16] Due to these high fixed costs, the electric utilities used to be vertically integrated—they used to own "two or more stages of production or distribution (or both) that are usually separate."[17] This meant that the electric utilities were significant monopolies that used to own assets within the generation, transmission, and distribution sectors so that they could lower risks in their supply chains, reach an economy of scale for generation, and unlock transmission and distribution network efficiencies.[18]

Due to the fears of monopoly abuses (as seen in other industries or argued in the cases) such as outrageous rates, curtailed production, and utility bankruptcy, state (and later federal) regulators adopted cost-of-service regulation to ensure that rates could enable cost recovery and a reasonable return on investment.[19] Hence, the cost of electricity service plus a return on investment for each type of asset were passed on to electricity consumers.[20] However, as com-

5. California ISO, Interconnection Basics 1,7 (2014), http://www.caiso.com/documents/interconnectionoptionsbasics.pdf.
6. Michael Dworkin et al., *Energy Transmission and Storage*, *in* The Law of Clean Energy: Efficiency and Renewables 531-32 (Michael B. Gerrard ed., ABA Section of Environment, Energy, and Resources 2011).
7. *Record Amounts of Zero-Carbon Electricity Generation and Storage Now Seeking Grid Interconnection*, *supra* note 1.
8. Lawrence Berkeley National Laboratory, *Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection*, https://emp.lbl.gov/queues (last visited July 10, 2023).
9. Rand et al., *supra* note 2, at 8.
10. *Record Amounts of Zero-Carbon Electricity Generation and Storage Now Seeking Grid Interconnection*, *supra* note 1.
11. Rand et al., *supra* note 2, at 18.
12. Rich Glick & Matthew Christiansen, *FERC and Climate Change*, 40 Energy L.J. 1 (2019), *available at* https://www.eba-net.org/wp-content/uploads/2023/02/Glick-and-ChristiansenFinal_Online.pdf.
13. U.S. Department of Energy, Office of Policy, *Queued Up . . . but in Need of Transmission*, https://www.energy.gov/policy/queued-need-transmission (last visited July 10, 2023).
14. *See* London Economics International LLC, Repowering America: Transmission Investment for Economic Stimulus and Climate Change (2021), https://wiresgroup.com/wp-content/uploads/2021/05/WIRES-Repowering-America-transmission-investment-May-5.pdf.
15. Midcontinent Independent System Operator, Transmission Cost Estimation Guide for MTEP22, at 44-45 (2022), https://cdn.misoenergy.org/20220208%20PSC%20Item%2005c%20Transmission%20Cost%20Estimation%20Guide%20for%20MTEP22_Draft622733.pdf.
16. *See generally id*. at 2-48.
17. Robert D. Buzzell, *Is Vertical Integration Profitable?*, Harv. Bus. Rev. (Jan. 1983), https://hbr.org/1983/01/is-vertical-integration-profitable.
18. *See generally* Adam Hayes, *Vertical Integration Explained: How It Works, With Types and Examples*, Investopedia (May 30, 2023), https://www.investopedia.com/terms/v/verticalintegration.asp.
19. *See generally* Munn v. Illinois, 94 U.S. 113 (1876); Public Utils. Comm'n of R.I. v. Attleboro Steam & Elec. Co., 273 U.S. 83 (1927); Federal Power Comm'n v. Natural Gas Pipeline Co. of Am., 315 U.S. 575 (1942); Federal Power Comm'n v. Hope Nat. Gas Co., 320 U.S. 591 (1944).
20. *See* Joel B. Eisen et al., Energy, Economics, and the Environment 479-80, 683-84, 687 (5th ed. 2019); *see also* New York v. Federal Energy Regul. Comm'n, 535 U.S. 1, 5 (2002).

petition in the generation sector increased over time, and as FERC found transmission to be a practice that affects interstate electricity rates, FERC has issued transmission regulations to enhance competition, to remove opportunities for discrimination, and to promote system reliability.[21] Within the context of developing interconnection regulations, the high costs of transmission construction alongside the history of vertical integration in the power sector demonstrate that a key theme of utility regulation is at play—the presence of a trade off and tension, of protecting the benefits of vertically integrated incumbents while fostering a level playing field for new entrants to support more competitive markets.[22]

It is worth noting that transmission is a resource that does not cleanly fit into economic categories. The interconnection regulations attempt to cause transmission assets/services to be common resources, but they are still a private good with externalities due to shortages (as indicated by the queues and future transmission needs, discussed above) and the steps in which capacity is allocated. Transmission resources are excludable and rivalrous in consumption—capacity is presumed to be fixed under static line ratings,[23] and additional interconnections cause capacity to be consumed in the absence of network upgrades. Adding another layer of complexity, it is difficult to track the flows of electricity on the grid,[24] driving controversial cost allocation uncertainties and imprecise methodologies.[25]

These attributes make it very challenging to efficiently allocate the use of transmission resources. The policy recommendation that emerges from this Article is to think about how we can use the transmission capacity that we currently have more efficiently and effectively in the short term, while we look for ways to build more transmission capacity and network upgrades in the short term and long term. An examination of interconnection regulations within the system of utility regulation can reveal paths forward to help us solve our interconnection challenges that are hindering our decarbonization and grid modernization efforts and making such efforts more costly and time-consuming.

This Article hypothesizes that there are potential solutions hidden within the network and current system of utility regulation. Part I reviews FERC's regulatory authority. Part II discusses the statutory underpinnings of the interconnection process. Part III considers FERC's open access requirements in FERC Order No. 888. Parts IV and V examine FERC's efforts to standardize the interconnection process for large and small generators in Orders Nos. 2003 and 2006, respectively.

Part VI explores FERC's efforts to use the interconnection process to improve reliability in Order No. 842. Part VII analyzes FERC's efforts to improve the interconnection process in Order No. 845. Part VIII delves into the Commission's most recent rulemaking from the summer of 2023. Part IX concludes with a reflection of the problem and a discussion of policy recommendations.

## I. FERC's Regulatory Authority

Before the Federal Power Act (FPA) was enacted, there was a jurisdictional issue for interstate transmission lines, where the in-state company and the out-of-state company would quarrel over the appropriate rate for the out-of-state customers due to fears of cross-state subsidization and discrimination.[26] The U.S. Supreme Court held that this type of transaction was not to be regulated by either state, for "if regulation is required it can only be attained by the exercise of power vested in Congress."[27] Congress responded with the FPA to enable the Federal Power Commission (FPC), the predecessor to FERC, to regulate.

Section 201 of the FPA establishes FERC's jurisdictional authority to regulate transactions in the electricity industry when the transactions are at wholesale and are a part of interstate commerce.[28] Section 201 categorizes the transactions into sales and transmissions. A transmission or sale is in interstate commerce if the transmission line crosses a state boundary.[29] The sale is a wholesale transaction if the electricity is not transmitted to the ultimate consumer; that is, if the electricity is being sold for resale.[30] Subsection (a) declares:

> [T]he business of transmitting and selling electric energy for ultimate distribution to the public is affected with a public interest, and that Federal regulation . . . of the transmission of electric energy in interstate commerce and the sale of such energy at wholesale in interstate commerce is necessary in the public interest . . . .[31]

21. Order No. 888, Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities, 75 FERC ¶ 61080, at 5 (1996); *see also New York v. Federal Energy Regul. Comm'n*, 535 U.S. at 11; *see also* South Carolina Pub. Serv. Auth. v. Federal Energy Regul. Comm'n, 762 F.3d 41, 50 (D.C. Cir. 2014).
22. *See* Eisen et al., *supra* note 20, at 17 ("Even though competition is an enduring theme for energy law, the reality is that vital components of the industry remain monopolies that are heavily regulated.").
23. Peter Behr, *Why Utilities Resist Simple Upgrades to Boost Renewables*, E&E News (Nov. 23, 2022), https://www.eenews.net/articles/why-utilities-resist-simple-upgrades-to-boost-renewables/.
24. *See New York v. Federal Energy Regul. Comm'n*, 535 U.S. at 7 ("any electricity that enters the grid immediately becomes a part of a vast pool of energy that is constantly moving in interstate commerce"); *see also* Joseph P. Tomain, *The Past and Future of Electricity Regulation*, 32 Env't L. 435, 454 (2002) ("The regulatory headache is that no one knows the point of origin of any electricity. They simply know how much is in the system and how much generators are willing to charge. Nor does anyone know the direction that electricity is flowing.").
25. *See* Illinois Com. Comm'n v. Federal Energy Regul. Comm'n, 756 F.3d 556, 565 (7th Cir. 2014) (Cudahy, J., dissenting) ("Cost allocation, particularly at these extraordinarily high voltages, is far from a precise science, and there are no mathematical solutions to determining benefits region by region or subregion by subregion.").
26. *See generally* Public Utils. Comm'n of R.I. v. Attleboro Steam & Elec. Co., 273 U.S. 83, 85-87 (1927).
27. *Id*. at 90.
28. 16 U.S.C. §824(b).
29. *See id*. §824(c).
30. *Id*. §824(d).
31. *Id*. §824(a).

However, Congress intended to preserve the states' traditional regulatory authority over intrastate retail sales, so the end of subsection (a) specifies that federal regulation and authority is "to extend only to those matters which are not subject to regulation by the States."[32] Thus, states retain police power over generation facilities, local distribution facilities, retail transmissions in intrastate commerce, or transmissions that are consumed by the transmitter.[33]

Sections 205 and 206 of the FPA require all jurisdictional rates and charges to be just and reasonable, and declare unjust and unreasonable rates to be unlawful; the Act further requires the Commission to remedy any underlying "rule, regulation, practice, or contract" that may cause a rate to be unjust and unreasonable so that the Commission can fix a rate that is just and reasonable.[34] As we will see when we discuss each interconnection regulation, FERC generally invokes these statutory provisions when promulgating the regulations to solidify its statutory authority and jurisdiction for the regulation.

## II. The Statutory Interconnection Process

### *A. FERC's Limited Ability to Mandate Interconnection: 16 U.S.C. §824a*

16 U.S.C. §824a(b) is the first mention of interconnection in the U.S. Code. After a state or a transmission owner/provider applies to the Commission, and the Commission provides notice to the affected parties and a hearing, the Commission determines if it has jurisdiction to enter an order to establish physical connection. However, the statute makes clear that the Commission lacks "authority to compel the enlargement of generating facilities for such purposes, [or] to compel such public utility to sell or exchange energy when to do so would impair its ability to render adequate service to its customers."[35] The statute also enables the Commission to have discretion to decide the terms and conditions of the interconnection.[36] While the Commission invokes its §§205 and 206 statutory authority in its interconnection regulations, it is apparent that §824a forms the statutory foundation for the processes that the Commission later establishes and follows.

A seminal case that discusses FERC's authority to mandate interconnection under §824a is *Otter Tail Power Co. v. United States*. In *Otter Tail*, the utility used its transmission infrastructure to block several municipalities from accessing competitors' electricity when it attempted to raise wholesale prices.[37] While reviewing the legislative history of the FPA, and finding "an overriding policy of maintaining competition to the maximum extent possible consistent with the public interest,"[38] the Supreme Court ruled that "the thrust of the FPA §202 is to encourage voluntary interconnections. Only if a power company refuses to interconnect voluntarily may the FPC, subject to limitations, order the interconnection." As a result, the Court upheld the district court's order for Otter Tail to interconnect, holding that the FPA did not completely shield Otter Tail from anti-trust regulation.[39]

### *B. FPA Amendments to Enable FERC to Mandate Interconnection: 16 U.S.C. §§824i and 824k*

In a footnote in *American Paper Institute, Inc. v. American Electric Power Service Corp.*, the Court explains that Congress revised the FPA to enable FERC to mandate interconnections, while limiting the jurisdictional consequences of the interconnection for intrastate utilities.[40] Section 824a(b) was not sufficient for encouraging utilities to make voluntary connections because the electricity grid itself is interstate in character. Hence, by connecting to the grid, the utilities' transmissions and sales would have become interstate, and they would have exposed themselves to FERC's jurisdiction and all of the regulations under the FPA.[41]

16 U.S.C. §824i vests FERC with authority to mandate interconnection as part of the Public Utility Regulatory Policies Act's (PURPA's) amendments to the FPA. After an electric utility, a qualifying cogenerator, or a qualifying small power producer applies to the Commission, the Commission may order transmission interconnection; actions needed to make the interconnection "effective"; sales, purchases, and coordination of electricity; or an increase of transmission capacity to support the interconnection.[42] States may also petition the Commission to do the same.[43]

After the Commission receives the application, the Commission provides notice to the relevant and affected stakeholders and the public, and may conduct an evidentiary hearing to determine whether to require a stakeholder to purchase the electricity from the new project.[44] Subsection I establishes factors or criteria that the Commission must consider: (1) whether mandating the interconnection would be in the public interest; (2) whether the interconnection would promote "conservation of energy or capital," "optimize efficiency of facilities and resources," or improve system reliability; and (3) whether the order complies with the requirements of §824k.[45] The public interest requirement means that the interconnection must be within the Commission's jurisdictional scope—the transmission for the interconnection must be

32. *Id.*
33. *See generally* New York v. Federal Energy Regul. Comm'n, 535 U.S. 1 (2002); *see also* Hughes v. Talen Energy Mktg., L.L.C., 578 U.S. 150, 166, 46 ELR 20078 (2016).
34. 16 U.S.C. §§824d(a), 824e(a).
35. *Id.* §824a(b).
36. *Id.*
37. Otter Tail Power Co. v. United States, 410 U.S. 366, 368 (1973).
38. *Id.* at 374.
39. *See id.* at 376; *see also* Sunflower Elec. Coop., Inc. v. Kansas Power & Light Co., 603 F.2d 791, 797 (10th Cir. 1979).
40. 461 U.S. 402, 422 n.12 (1983).
41. *Id.*
42. 16 U.S.C. §824i(a)(1)(A)-(D).
43. *Id.* §824i(a)(2).
44. *Id.* §824i(b)(1)-(3).
45. *Id.* §824i(c).

interstate in character or it must be within an interstate wholesale transaction or market.[46]

The third requirement is that the order must meet the standards set out in §824k. Under §824k(c)(1), the statute requires the Commission to issue a proposed order and then to give the parties a reasonable amount of time to agree to the terms and conditions to implement the order, including the cost allocation. As a result, the proposed order is not yet legally binding, and it is a starting point for negotiations between the parties. Additionally, subsection (c)(1) expressly declines to give the courts subject matter jurisdiction to review or enforce the proposed order.[47] The Commission may also shorten the time for negotiation to prevent parties from intentionally delaying an agreement to jeopardize a project.[48] The subsection also requires the Commission to review the terms and conditions that the parties agree upon.[49]

Should the parties agree on the terms and conditions with the Commission's approval of the agreement, the Commission must include those terms and conditions in the final order, and the agreement becomes legally binding upon the parties.[50] However, if the parties are unable to reach an agreement or if the parties agree, but the Commission cannot approve the resulting terms and conditions, the Commission may replace the negotiated terms and conditions with terms and conditions that the Commission prescribes in the final order.[51]

Courts have upheld and taken notice of the impact of FERC's exercise of its interconnection authority under §§824i and 824k. For example, in *American Paper Institute, Inc.*, the Court found that rules requiring physical interconnections are incidental to the rules that require purchases and sales from qualifying facility and small power producers, as an interconnection is necessary "to consummate purchases and sales authorized by PURPA."[52] In 2004, the U.S. Court of Appeals for the Ninth Circuit noted that FERC's FPA jurisdiction includes "the authority to order interconnection to the grid and to specify the terms of the interconnection" under §§824i and 824k.[53]

In 2007, the U.S. Court of Appeals for the District of Columbia (D.C.) Circuit upheld FERC Order No. 2003 (discussed below), despite the impacts on non-jurisdictional states as co-owners of transmission facilities.[54] Noting that the regulation is meant to protect interstate transmissions and wholesale sales from market power, the court found "no impingement that exceeds what may be encompassed in such conventional exercises of jurisdiction."[55] The court also stated:

> To the extent that Order No. 2003 conditions a jurisdictional utility's participation in the transmission and interconnection markets on that utility's securing physical changes in the facilities, and those changes bear a close enough relation to FERC's exercise of jurisdiction over jurisdictional transactions . . . the Order effects no legally material extension of [its FPA authority].[56]

In 2019, the Ninth Circuit found that it did not have to review a transmission tariff for the Bonneville Power Administration under an undue discrimination standard, as FERC did not exercise its authority under §824i to mandate an interconnection.[57]

Sections 824i and 824k are included in this Article as they demonstrate that, if the need for more transmission capacity becomes dire enough, the Commission might have statutory authority to mandate parties to establish interconnections to the wholesale markets. Although it is a possibility that these provisions are vestiges of the days of vertically integrated utility monopolies, the statute offers an opportunity to FERC to force transmission resources onto the wholesale markets. But using this authority should be a last resort—it is foreseeable that it would be undesirable for the Commission to invoke this authority, as it would be expensive politically, administratively, and economically. Allowing the parties to negotiate, to file their proposals with the Commission, and to receive approval before starting construction and cost recovery from ratepayers ensures that the transmission project is given ample planning and consideration to different types of benefits, disadvantages, and risks.

If the Commission mandates the interconnection for jurisdictional entities, the resulting transmission project may have unintended consequences and perverse incentives for all parties involved, especially the ratepayers that would ultimately pay for the service. For example, it is entirely possible that in response to the use of this statutory authority, potential generators may flood the Commission with requests for mandated interconnections. However, if the Commission could demonstrate that there are no feasible alternatives to mandating a particular interconnection, then it is desirable for the Commission to exercise this statutory authority if the particular interconnection is valuable enough and urgently needed. Hence, the Commission should use this authority if market forces prove to be too slow to act to respond to the evolving demands and stresses on our power grid that threaten reliability.

46. *See id.* §824(a).
47. *Id.* §824k(c)(1).
48. *Id.*
49. *Id.*
50. *Id.* §824k(c)(2)(a).
51. *Id.* §824k(c)(2)(b).
52. American Paper Inst., Inc. v. American Elec. Power Serv. Corp., 461 U.S. 402, 418 (1983).
53. Southern Cal. Edison Co. v. Public Utils. Comm'n, 121 Cal. App. 4th 1303, 1311 (Cal. Ct. App. 2004).
54. National Ass'n of Regul. Util. Comm'rs v. Federal Energy Regul. Comm'n, 475 F.3d 1277, 1281 (D.C. Cir. 2007).
55. *Id.* at 1280.
56. *Id.* at 1282.
57. Sacramento Mun. Util. Dist. v. Bonneville Power Admin., 772 F. App'x 503, 505 (9th Cir. 2019).

## III. Wholesale Competition Through Open Access: FERC Order No. 888

FERC promulgated Order No. 888 to foster competition, to remedy undue discrimination in access to transmission wires, and to increase efficiency.[58] FERC invoked §§205 and 206 of the FPA as the statutory authority for the rulemaking.[59] Under these statutory responsibilities, the Commission required jurisdictional utilities to engage in functional unbundling,

> to file open access non-discriminatory transmission tariffs that contain minimum terms and conditions of non-discriminatory service;
>
> to take transmission service (including ancillary services) for their own new wholesale sales and purchases of electric energy under the open access tariffs; [and]
>
> to develop and maintain a same-time information system that will give existing and potential transmission users the same access to transmission information that the public utility enjoys, and further requires public utilities to separate transmission from generation marketing functions and communications[.][60]

Order No. 888 also allows public utilities to "seek recovery of legitimate, prudent, and verifiable stranded costs associated with providing open access."[61] Order No. 888 was promulgated in a context of economic and technological changes to the power industry. Among these changes, the Commission found that smaller generation units/facilities were able to capitalize on smaller economies of scale, and that new technologies facilitated long-distance, high-voltage transmission.[62]

Small-scale generation with long-distance transmission was a recipe for more competition in the generation sector, but the transmission market still had monopolistic features. As a result, transmission owners were able to wield market power to prevent new entrants from accessing the markets.[63] This problem prompted the Commission to facilitate open access for transmission, by requiring transmission owners to offer comparable terms and conditions that it would offer to its own generation facilities to other generators.

To facilitate open access transmission, the Commission relies on functional unbundling, and expressly declined to use corporate unbundling—requiring utilities to completely divest themselves of vertically integrated assets to choose a sector to operate within—and chose to merely encourage operational unbundling to separate ownership from operation of transmission assets.[64]

However, the Commission did not find functional unbundling to be enough. The Commission opted to have "safeguards" in place to ensure that the rule was effective.[65] The safeguards include a code of conduct for transmission providers that would separate transmission function employees from marketing function employees: §206 complaints that enable market participants to notify the Commission of utility misconduct or affiliate abuse, and investigatory proceedings under §206.[66] While the Commission did not set out its standards of conduct in Order No. 888, it did so in Order Nos. 889, 2004, and 717, which are outside the scope of this Article. However, it is worth noting that, generally, Order No. 717 requires transmission employees to function independently from marketing employees; prohibits communication/disclosure of certain types of nonpublic transmission function information to marketing function employees; and compels transmission providers to provide equal access to nonpublic transmission information to marketing function employees and transmission customers when disclosure is allowed.[67] With these safeguards in place, the Commission felt it had "a reasonable and workable means" through Order No. 888 to ensure nondiscriminatory open access transmission.[68]

FERC Order No. 888 was part of a broader movement for regulatory agencies to change their oversight and regulatory frameworks to move markets for commodities and essential services toward competition. Joseph Kearney and Thomas Merrill describe the previous regulatory framework of having the regulatory agencies closely observe and license monopolist firms to ensure standard services with regularly filed rates, establish and maintain market barriers to prevent entry and exit from the industry, and allow reasonable profits.[69] These two commentators find that Order No. 888 was part of a new regulatory framework characterized by differentiated services and prices, more deference to negotiated contracts, regulation of bottleneck facilities to prevent market power, and efforts to remove barriers to entry and exit to stimulate competition.[70] As a result, these authors state that Order No. 888 "works a fundamental restructuring of the interstate electric industry."[71]

Another commentator adds that FERC Order No. 888 was "the most significant event to date [as written in 1998] in electric industry restructuring."[72] Because the rulemaking required open access to transmission facilities

58. Order No. 888, Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, 75 FERC ¶ 61080, at 5 (1996).
59. *Id*. at 4.
60. *Id*.
61. *Id*. at 5.
62. *Id*. at 19-20.
63. *See id*. at 49-50.
64. *Id*. at 55-58.
65. *Id*. at 59.
66. *Id*.
67. *See* 18 C.F.R. §358.2(b)-(d); *see also* Scott Hempling, Regulating Public Utility Performance: The Law of Market Structure, Pricing, and Jurisdiction 187 (2d ed. 2021).
68. Order No. 888, 75 FERC ¶ 61080, at 59.
69. Joseph D. Kearney & Thomas W. Merrill, *The Great Transformation of Regulated Industries Law*, 98 Colum. L. Rev. 1323, 1325 (1998).
70. *Id*. at 1326.
71. *Id*. at 1354.
72. Jim Rossi, *The Common Law "Duty to Serve" and Protection of Consumers in an Age of Competitive Retail Public Utility Restructuring*, 51 Vand. L. Rev. 1233, 1280 (1998).

and for market participants to file wholesale transmission tariffs with the Commission,[73] independent power producers became "structurally competitive" with incumbent firms, while taking on industry risks often borne by the ratepaying consumers.[74] This scholar further adds that functional unbundling removed nepotism in transmission access to facilitate the development of competitive wholesale markets.[75]

A third commentator finds that the restructuring movement of the 1990s caused rates to decrease, innovation to increase, and administrative costs to decrease while causing "lower rates of return, greater risks, and occasionally the premature retirement of assets" for firms previously in the position of the regulated monopolist.[76]

Writing in the aftermath of September 11, 2001, and Enron's market manipulation to cause the California energy crisis, Joseph Tomain notes that Order No. 888 led to "the development of retail competition in the states, the divestiture of generating units by traditional utilities, an increase in energy company mergers, a notable increase in the number of power marketers and independent generators, and the establishment of independent system operators to manage transmission."[77] Tomain also finds that the transmission sector was not designed for large numbers of power pools and interconnections; it was designed "roughly for point to point deliveries."[78] As a result, the open access and pro-competitive policies embedded in Order No. 888 cause the grid to function differently from the way it was designed, which places stress on the infrastructure. Tomain forecasted that the stress would cause symptoms of congestion as sources of electricity generation would grow, while investment would lag behind.[79]

Order No. 888 was significant—it was a key moment in the restructuring of the electricity market to combat market power over transmission access and to facilitate competitive wholesale markets. It also serves as the foundation of FERC's rulemakings, and each later regulation builds on its momentum for regulating the wholesale markets to further develop and stimulate competitive forces. While FERC found Order No. 888 to be insufficient,[80] it later promulgated Order No. 2000 to create the regional transmission organizations (RTOs)/independent system operators (ISOs) for operational unbundling and to induce utilities to voluntarily join. Generally, an RTO/ISO is a regional organization that independently operates the transmission assets on behalf of the utility owner to administer the wholesale transmission market.[81] Order No. 2000 is outside of the scope of this Article, as it defines the characteristics and features of RTOs and ISOs and the incentives used to entice membership.[82]

## IV. Standardization of Interconnection

FERC Order No. 2003 sets forth the procedures and standard contract that the generator (the interconnection customer) and the transmission service provider must file when they negotiate the open access transmission tariffs (OATTs) for interconnection.[83] The rule requires the transmission providers to file revised OATTs to include standard large generator interconnection procedures (LGIP) and a standard large generator interconnection agreement (LGIA).[84] However, realizing that RTOs and ISOs have already achieved operational unbundling, FERC Order No. 2003 grants these types of independent organizations more flexibility to deviate from the standard procedures and agreement.[85]

The objectives of this regulation are to ensure just and reasonable terms and conditions for interconnection, while pursuing the protection of system reliability.[86] Like in Order No. 888, the Commission invoked §§205 and 206 of the FPA to establish its authority for the rule. The Commission responded to industrywide dissatisfaction with the case-by-case analysis through adjudication, as it was "inadequate and inefficient."[87] Interconnection requests are a bottleneck to competition, as they require the resolution of highly technical, complex, and expensive disputes over feasibility, cost, and cost allocation. Consequently, these procedural issues gave vertically integrated utilities a market advantage over competitors that had to negotiate for transmission access.[88]

The LGIP details the steps for a generator to obtain interconnection. The generator first sends a request to the transmission provider. The interconnection customer must provide a $10,000 deposit, preliminary site documentation, and the expected in-service date of the project. When the transmission provider receives the materials from the generator, the transmission provider acknowledges receipt and, if applicable, notifies the generator if the request is deficient.[89] If the request is complete, the generator is now in the interconnection queue, and the transmission provider assigns the project a queue position to determine the priority for performing the interconnection studies and allocating costs.[90]

Next, the parties hold a scoping meeting to discuss alternative points for interconnection and to share technical data. After the scoping meeting, either the transmission

73. *Id*.
74. *Id*. at 1279.
75. *Id*. at 1280.
76. Herbert Hovenkamp, *The Takings Clause and Improvident Regulatory Bargains*, 108 Yale L.J. 801, 802 (1999).
77. Tomain, *supra* note 24, at 455-56.
78. *Id*. at 470.
79. *Id*.
80. John S. Moot, *Whither Order No. 888?*, 26 Energy L.J. 327 (2005).
81. FERC, *RTOs and ISOs*, https://www.ferc.gov/power-sales-and-markets/rtos-and-isos (last updated Mar. 22, 2023).
82. *See generally* Order No. 2000, Regional Transmission Organizations, 89 FERC ¶ 61285 (1999); *see also* Eisen et al., *supra* note 20, at 714-17.
83. Order No. 2003, Standardization of Generator Interconnection Agreements and Procedures, 104 FERC ¶ 61103, para. 2 (2003).
84. *Id*.
85. *Id*. para. 12.
86. *Id*. para. 7.
87. *Id*. para. 10.
88. *Id*. para. 11.
89. *Id*. para. 35.
90. *Id*.

provider or its independent contractors perform a series of interconnection studies to assess the specific plans in detail, to discover potential adverse system impacts, and to determine any required facility modifications for the interconnection to be implemented.[91] In the aggregate, the required studies can cost the generation developer $160,000 (in 2003 dollars) or more in forward deposits.[92] The feasibility study, impact study, and facilities study must be completed in the order listed, successively, without overlap.[93] A change in the queue position due to changed circumstances of other generation developers may cause any of the studies to be reconducted.[94] The transmission provider then synthesizes the results of these studies into a report and incorporates the figures into a draft interconnection agreement, to be used as a basis for further negotiations for transmission construction and upgrades.[95]

The D.C. Circuit recently decided a FERC Order No. 2003 case where a vertically integrated subsidiary of Xcel attempted to use streamlined procedures that allowed for independent organizations to replace retired generation it owned while it attempted to circumvent the standardized interconnection procedures within Order No. 2003.[96] The backlog of generators waiting in the interconnection queue represents the unintended consequence of standardizing interconnection.[97] Public Service Corporation of Colorado (PS Colorado), the subsidiary, operates more than 4,700 miles of transmission lines that serve approximately 75% of the state's population, while it produces 60% of the electricity on the network.[98] In 2020, PS Colorado filed an application with the Commission to streamline its interconnection procedures.

PS Colorado modeled their request on an ISO's request, which already obtained Commission approval.[99] The Commission rejected PS Colorado's application, finding a risk that PS Colorado could unduly preference its own generation, that prior acceptances were for grid operators that do not own generation facilities on the network, and that PS Colorado could lock up transmission capacity that would become unavailable to a new generator.[100] The ISO's variation from the standard interconnection procedure fell under the separate standard for variations for independent operators, but PS Colorado had a burden to show that its deviation would work as well as the standard procedure in Order No. 2003.[101]

PS Colorado argued that the Commission "irrationally concluded" that PS Colorado's plan was unduly discriminatory; that the Commission did not support its potential discrimination finding with substantial evidence; and that the agency contradicted its own precedent.[102] The court rejected all three arguments to uphold the Commission's differential treatment of the vertically integrated utility and the ISO. In response to the undue discrimination argument, the court noted that the Commission has broad discretion to define "undue discrimination" under §205 of the FPA.[103] Because the Commission used its discretion to construct a burdensome test to meet so that the Commission could fulfill the objectives of the regulation, the court upheld the Commission's orders under the arbitrary and capricious standard of review.[104]

On the substantial evidence argument, the Court affirmed the Commission's use of findings based on mere economic theory and predictions, as opposed to actual observations. The Commission's decision was well supported by the company's 60% market share; the country's past experience with discrimination from vertically integrated natural gas and electric utilities; and the Commission's technical finding that favoring the utility's proposed generation replacement would discourage competition and serve as a barrier to entry for new competitors.[105]

This case demonstrates the tension of energy law between incumbents and new entrants. It also shows that the Commission has significant deference in policymaking under the "just and reasonable" standard when it weighs the benefits, drawbacks, and risks of policy actions. Here, the risk of hindering competition was so great that the agency was able to justify its decision without providing data; just the theory and prediction of anticompetitive behavior in conflict with the purposes of Order No. 2003 were strong enough reasons for the Commission to defend its policy.

Finally, this case illustrates that the "just and reasonable" standard is elastic, like a rubber band, to allow the Commission to respond to different facts and circumstances while implementing its regulations. A rubber band will "snap" back to its original state after being stretched too far. Here, the stretch of an approved ISO/RTO practice to a vertically integrated utility caused the rubber band of the "just and reasonable" standard to snap, to preclude PS Colorado from the practice of streamlining replacement generation interconnection.

The impact of FERC Order No. 2003 is that, although well-intentioned for removing unduly discriminatory practices for interconnection, its underlying assumption that the interconnection customer causes the cost and need for system upgrades has been a major driver for the interconnection queue withdrawals and delays.[106] Even back in 2009, Stephen Fisher noted that "contributing to the grow-

91. *Id.* para. 36.
92. *See id.*
93. *Id.* para. 37.
94. *Id.*
95. *Id.* para. 38.
96. Xcel Energy Servs. Inc. v. Federal Energy Regul. Comm'n, 41 F.4th 548 (D.C. Cir. 2022).
97. *See id.* at 553.
98. *See id.*
99. *Id.* at 554.
100. *Id.* at 551, 555.
101. *Id.*
102. *Id.* at 557.
103. *See id.*
104. *Id.* at 557-60.
105. *See id.* at 560-61.
106. Julie Lieberman, Concentric Energy Advisors, How Transmission Planning & Cost Allocation Processes Are Inhibiting Wind & Solar Development in SPP, MISO, & PJM vi-vii (2021), https://acore.org/wp-content/uploads/2021/03/ACORE-Transmission-Planning-Flaws-in-SPP-MISO-and-PJM.pdf; *see generally* FERC, Notice of Proposed Rulemaking, Improvements to Generator Interconnection Procedures and Agreements, 87 Fed. Reg. 39934 (July 5, 2022), discussed below.

ing interconnection queue backlogs is the increasing frequency of delays in processing interconnection studies."[107] Part of the problem is that when a grid upgrade is installed, the interconnection customer does not realize the full benefit of its expense because other members of the interconnection queue and other generators on the system are able to benefit to some degree from the upgrade.

Thus, interconnection customers are disincentivized to move forward on projects after costs are identified through the grid studies, and when they withdraw, the studies have to be recompleted for a different potential customer in the queue. Even worse, higher-queued customers have historically been able to push the costs of incomplete upgrades onto lower-queued customers during queue withdrawal as transmission providers would negotiate under the presumption that all higher-queued customers would interconnect.[108] Melissa Powers argues that transmission providers were able to thwart the pro-competitive policies behind FERC Order No. 2003, as the transmission providers had the ability to "play a gatekeeping role" by "slow-rolling the studies and other aspects of the interconnection process."[109]

Both FERC Order No. 2003 and *Xcel Energy Services Inc.* demonstrate that, although generally desirable, an organized queue system is difficult to implement efficiently. Under Order No. 2003, interconnection customers must continuously study how they would impact the system, but they are able to pull out of the queue after the studies are complete, and the studies have limited value for other potential interconnections. As a result, the studies only have the value of identifying needed upgrades to accommodate one project, and if the project does not move forward, the upgrade may still have to be made by a lower-queued customer, and a new study is also needed.

These problems demonstrate that upgrades have both positive externalities and negative externalities in the form of spillover effects. These externalities are problematic, as markets with externalities generally misallocate resources without policy interventions.[110] The positive externality is from the perspective of the higher-queued interconnection customers and the negative externality is from the perspective of lower-queued customers. The positive externality is in the form of a spillover that is caused by lower-queued customers benefiting from the network upgrades undertaken for a completed higher-queued project. In some cases, the later-ranked project can freeride on an earlier upgrade, paid for by a higher-ranked interconnection customer.[111] This positive externality and spillover may be large enough to cause earlier interconnection customers to surmise that their projects will not yield sufficient return on investment for them to complete, so they accept their sunk costs in withdrawing from the queue, and their decision further delays and adds to the total costs of new generation because the upgrade for the cancelled project is presumed to still be needed.

When a higher-queued interconnection customer walks away, it triggers requirements for lower-queued customers to restudy the interconnection, and it pushes the burden of the upgrade onto the next customer in the queue, even if the upgrade is not actually needed due to the project cancellation.[112] The costs and delays that are pushed onto lower-queued projects caused by higher-queued project withdrawals represent the negative externalities. Because the higher-queued interconnection customer is not able to fully benefit from their upgrade, and does not bear the full cost of withdrawal decisions by triggering requirements for lower-ranked projects to recomplete the studies, the market for grid interconnection is saddled with externalities, with the result of a misallocation of interconnection resources.

Compounding these problems further, changes to the queue caused by project withdrawal are not accounted for and reflected in grid planning models, and, consequently, the models do not accurately represent future transmission needs.[113] Julie Lieberman finds that, "Generators are unable to move through the queues without more transmission capacity, but the need for new transmission capacity identified in RTO planning processes somewhat depends on the generators' ability to move through the queues and secure signed interconnection agreements."[114] These problems caused by FERC Order No. 2003 are further explored and discussed when we cover later regulations and proposals below.

## V. Standardization of Small Generator Interconnection

While FERC Order No. 2003 required standardized interconnection procedures for large generation facilities, defined as having more than 20 megawatts (MW) of capacity, FERC promulgated Order No. 2006 to address the interconnection procedures for small generation facilities, defined as having a capacity of 20 MW or less.[115] FERC's objectives were to decrease interconnection time and costs, increase diversity and quantity of generation for competition in the wholesale power markets, increase total energy supply, preserve grid reliability, promote development of

107. Stephen M. Fisher, *Reforming Interconnection Queue Management Under FERC Order No. 2003*, 26 Yale J. on Regul. 117, 131 (2009).
108. *Id.* at 132.
109. Melissa Powers, *Anticompetitive Transmission Development and the Risks for Decarbonization*, 49 Env't L. 885, 909 (2019).
110. *See, e.g.*, Robert H. Frank, Microeconomics and Behavior 552 (7th ed. 2008).
111. *See* FERC, Notice of Proposed Rulemaking, Improvements to Generator Interconnection Procedures and Agreements, 87 Fed. Reg. 39934, 39940 (July 5, 2022) ("A withdrawal may necessitate re-studies and cause the shifting of network upgrade costs to lower-queued interconnection customers.").
112. *See id.* at 39945 ("If the interconnection customer does not withdraw and pays for the network upgrade to be constructed, lower-queued interconnection customers that will benefit from the network upgrade are not required to share cost responsibility simply because they submitted an interconnection request at a later date.").
113. John P. Banks, *The Decarbonization Transition and U.S. Electricity Markets: Impacts and Innovations*, 11 WIRES Energy & Env't e449 (2022), https://doi.org/10.1002/wene.449.
114. Lieberman, *supra* note 106, at vii-viii.
115. Order No. 2003, Standardization of Generator Interconnection Agreements and Procedures, 104 FERC ¶ 61103, para. 1 (2003); Order No. 2006, Standardization of Small Generator Interconnection Agreements and Procedures, 111 FERC ¶ 61220, para. 1 (2006).

alternative nonpolluting energy resources, and implement §§205 and 206 of the FPA to remedy undue discrimination.[116] Another motivation for this rule was nationwide consistency to harmonize state and federal practices.[117]

While promulgating Order No. 2006, FERC wanted to achieve the same functions and steps as Order No. 2003. Order No. 2003 established the LGIP's use of scoping meetings, feasibility studies, system impact studies, and facility studies for examining the impact of the proposed interconnection on the electricity grid and identifying the equipment and modifications for accommodating the new generation.[118] FERC wanted to establish a standardized interconnection process for small generation facilities to manage reliability and safety risks, and it opted to prescribe three methods for evaluating interconnection requests: a default study process for any small generating facility, a fast track process for facilities that are 2 MW or less,[119] and a 10 kilowatt (kW) inverter process for facilities no larger than that size.[120]

The small generation interconnection procedures (SGIP) are largely the same as the LGIP. When the transmission provider receives the interconnection request from the interconnection customer, the interconnection customer will receive a queue position and pay a feasibility study deposit or a processing fee if the interconnection customer is using the fast track process or the 10 kW inverter process.[121] Next, the transmission provider will conduct the studies used in the LGIP, and the interconnection customer pays the actual cost of conducting the studies.[122] Next, the parties use the study results to fill in the variable terms of the standardized small generator interconnection agreement (SGIA) to formalize the interconnection responsibilities of the parties.[123]

To implement the fast track process, the parties forego the four kinds of studies conducted in the study process and instead use technical screens to find potential reliability and safety issues. If the project passes the screenings, the transmission provider offers an SGIA.[124] If the project fails the screens, the generator may still receive an SGIA if the transmission provider finds that the interconnection would not affect safety and reliability.[125] Under the circumstance that the project fails the screenings and the transmission provider finds a potential degradation of the system's safety and reliability attributes, the parties may have one more meeting to discuss options available to the interconnection customer.[126]

If this meeting takes place, "the Transmission Provider must offer to perform a supplemental review of the proposed interconnection, paid for by the Interconnection Customer, to identify Upgrades needed to accommodate the interconnection."[127] Should the interconnection customer accept the offer, the parties enter into an SGIA. However, if the transmission provider remains uncertain about the safety and reliability impacts of the interconnection, the study process and all of its studies are used to evaluate the interconnection, and the parties execute the SGIA.[128]

The 10 kW inverter process is only available for certified generators, and the "all-in-one" document "includes a simplified application form, interconnection procedures, and a brief set of terms and conditions (akin to an interconnection agreement)."[129] This process shares the same technical screens as the fast track process, and the transmission provider has the burden of proof to demonstrate that the interconnection cannot occur safely and reliably to reject the interconnection customer's application.[130] After approval, the interconnection customer installs the equipment and certifies the installation, and the transmission provider inspects the interconnection. Because the transmission provider already agreed to the terms and conditions in the all-in-one document, the interconnection is complete.[131]

The regulation may have had unexpected consequences. Although FERC attempted to streamline the regulations for small generators and level the regulatory field for generators of all sizes, it is an unlikely possibility that expedited processes actually backfired. While data on the interconnection process are very limited, with Massachusetts being the only state with "detailed data available on interconnection processes completed from the beginning of the application process to the end,"[132] one National Renewable Energy Laboratory (NREL) study analyzed Massachusetts' data on projects that underwent the SGIP between 2009 and 2013.

The NREL scientists found that about two-thirds of the projects without a pre-application report went through the fast track process. Of the projects without a pre-application report that went through the fast track process, almost 16% made it to the stage where the transmission provider and interconnection customer sign an interconnection agreement.[133] On the other hand, projects without a pre-application report that went through the full study process had an interconnection agreement rate of nearly 18%.[134] For projects with a pre-application report, almost 40% went through the interconnection process, and almost 14%

116. Order No. 2006, 111 FERC ¶ 61220, at para. 1.
117. *Id*. at para. 4.
118. *Id*. at para. 35.
119. The fast track process has been amended to accommodate projects as large as 5 MW in 2013, but this Article is reporting on what is in Order No. 2006. *See* Order No. 792, Small Generator Interconnection Agreements and Procedures, 145 FERC ¶ 61159, para. 103 (2013).
120. Order No. 2006, 111 FERC ¶ 61220, at para. 43.
121. *Id*. at para. 42.
122. *Id*. at para. 44.
123. *Id*. at para. 44.
124. *Id*. at para. 45.
125. *Id*.
126. *Id*. at para. 45.
127. *Id*.
128. *Id*.
129. *Id*. at para. 46.
130. *Id*.
131. *Id*.
132. Zachary Peterson & Eric Lockhart, National Renewable Energy Laboratory, Evaluating the Role of Pre-Application Reports in Improving Distributed Generation Interconnection Processes 6 (2018) (NREL/TP-7A40-71765), https://www.nrel.gov/docs/fy19osti/71765.pdf.
133. *Id*. at 12 fig.5.
134. *Id*.

reached an interconnection agreement.[135] Of the remaining 60% that went through the standard studies, approximately 43% reached an interconnection agreement.[136]

While these data were collected to study the effectiveness of a pre-application report, if we were to make a large assumption that the data for Massachusetts are representative and consistent with national trends, and constant over time, then the data would indicate that the fast track process is not very effective, since most projects that make it into the queue are studied extensively. However, given the limited nature of this data set, the above conclusion is also very speculative and of limited robustness. If anything, perhaps more data like those reported by Massachusetts are needed so that the SGIP and LGIP can be studied more extensively with more robust and applicable conclusions for policy evaluation and analysis.

## VI. Improving Reliability

In Order No. 842, the Commission required frequency response as a condition precedent to interconnection for both synchronous and nonsynchronous generators, large and small.[137] The Commission invoked its FPA §206 authority to level the playing field for large synchronous generation facilities by providing comparable requirements for the provision of frequency response by nonsynchronous generators in response to "technological advancements that . . . enable new non-synchronous generating facilities primary frequency response capabilities."[138] The Commission explains that frequency response is needed to ensure grid reliability, as sudden changes in load and generation impact the balance of the grid, and if the balance of the grid varies too far above or below 60 hertz (Hz) (the scheduled frequency in North America), then there are risks of "under frequency load shedding (UFLS), generation tripping, or cascading outages."[139]

Primary frequency responses are "automatic and autonomous actions," outside of the system operator's control, and they stabilize frequency by mitigating the deviations.[140] The Commission found that "generator owners and operators can independently decide whether to configure their generating facilities to provide primary frequency response," and they can determine how much and when to provide the service.[141] Thus, the Commission found an industrywide under-provisioning of the service.[142] Additionally, the Commission was concerned about the increasing retirements of conventional generation facilities and their replacement by variable energy resources.[143]

One reform of Order No. 842 was that the Commission "require[d] newly interconnecting large and small generating facilities that interconnect pursuant to the *pro forma* LGIA or *pro forma* SGIA, to install, maintain, and operate a functioning governor or equivalent controls capable of providing primary frequency response."[144] The Commission defined "functioning governor or equivalent controls" as "the required hardware and/or software that provides frequency responsive real power control with the ability to sense changes in system frequency and autonomously adjust the generating facility's real power output . . . in the direction needed to correct frequency deviations."[145]

Another function of Order No. 842 was "to include . . . operating requirements of a maximum droop setting of 5 percent and deadband setting of ±0.036 Hz for primary frequency response in the pro forma LGIA and pro forma SGIA."[146] Recognizing that local balancing authorities and regions may have different needs, the maximum droop and deadband settings are minimum interconnection requirements, and the Commission reserved the ability to impose more stringent requirements.[147]

This regulation is significant and valuable because FERC imposed frequency regulation on smaller, renewable energy providers to further the goal of grid reliability in response to technological developments that removed the rationale for treating the two types of electricity production technologies differently. FERC saw a shortage of frequency response services, and made their use a condition to wholesale market entry—a powerful incentive for generators to configure their systems to employ frequency response technologies on their generation facilities.

In February 2021, during Winter Storm Uri, the Electric Reliability Council of Texas (ERCOT) needed to employ UFLS as the cold weather caused massive amounts of generation to trip.[148] Had the UFLS failed, then 90% of the state would have faced a cascading blackout with the need for a blackstart operation that would have taken weeks to months.[149] While ERCOT is not regulated by FERC under §§205 and 206 of the FPA,[150] the example of Winter Storm Uri illustrates the role of frequency response as a shield and insurance policy to protect against the risks of extreme weather, which indicates that Order No. 842 can be analogized to a raincoat during a storm.

135. *Id*. at 12 fig.6.
136. *Id*.
137. Order No. 842, Essential Reliability Services and the Evolving Bulk-Power System—Primary Frequency Response, 162 FERC ¶ 61128, at 1 (2018).
138. *Id*. at 2-3.
139. *Id*. at 3.
140. *Id*. at 4.
141. *Id*. at 6.
142. *See id*. at 7-9.
143. *Id*. at 14-15.
144. *Id*. at 14.
145. *Id*. at 26-27.
146. *Id*. at 43.
147. *Id*.
148. *See generally* Christopher Neely, *ERCOT: Texas Power System Was Less Than 5 Minutes From Collapse During Winter Storm*, Cmty. Impact (Feb. 24, 2021, 8:59 PM), https://communityimpact.com/austin/central-austin/government/2021/02/24/ercot-texas-power-system-was-less-than-5-minutes-from-collapse-during-winter-storm/.
149. Because ERCOT serves approximately 90% of Texas. ERCOT, *About ERCOT*, https://www.ercot.com/about (last visited July 10, 2023).
150. FERC, *ERCOT*, https://www.ferc.gov/industries-data/electric/electric-power-markets/ercot (last updated July 14, 2022).

## VII. Further Interconnection Reform

FERC Order No. 845 was a major interconnection reform. The regulation contains several policies that are not included in this discussion, as this Article focuses on policies that are more relevant to the purposes here. The regulation is a package of policies aimed at increasing certainty for interconnection customers, encouraging more informed decisionmaking, and improving the interconnection process. The Commission responded to the changing electricity generation mix, interconnection customer complaints regarding inefficiency and discrimination, and management issues for transmission providers in the study process stemming from the risk of commercial inoperability of generation facilities.[151] As a result of these issues, interconnection queues were backlogged, interconnection requests were often withdrawn, and lower-queued customers faced higher cost burdens for grid upgrades.[152] These problems, in turn, impact the ability for interconnection customers to acquire financing, and serve as an obstacle to wholesale competition development.[153] Finding that these problems triggered §206, the Commission initiated the rulemaking.[154]

The first reform that the Commission considered was to require transmission providers to conduct cluster studies "on a scheduled, periodic basis," to increase certainty for interconnection customers.[155] However, the Commission rejected this reform in the final rule because the significance of the problem of "cascading restudies" did not justify constraining the restudy process in a "one size fits all approach."[156] The cause for restudies often results from project withdrawals, modifications of higher-queued projects, or a change to the point of interconnection, and such actions "may not be foreseeable or preventable."[157] While the reform would have reduced timing uncertainty, it would not have decreased cost uncertainty, and the Commission did not want to adversely impact the timing of projects through the reform.[158]

The second reform of Order No. 845 more readily enables interconnection customers to exercise an option to initiate construction of their generation facilities, regardless of whether the transmission provider has completed the stand-alone network upgrades and facilities for the interconnection in time.[159] This reform is intended to increase efficiency by allowing the interconnection customer to start construction sooner.[160] The Commission found that existing safeguards—such as the transmission provider's approval of the facility design, testing, and construction—protect system reliability.[161]

Another reform implemented in Order No. 845 requires "transmission providers to detail the methods they use to determine which facilities are contingent facilities."[162] Under Order No. 2003, the transmission providers identify the contingencies that impact the studies and include them in the LGIAs.[163] The Commission notes that accounting for the methodology used would make the interconnection process more transparent, as interconnection customers could be better informed, with "fewer interconnection disputes and withdrawals."[164]

Additionally, the reform also requires transmission providers to disclose "upon request of the interconnection customer, the estimated network upgrade costs and estimated in-service completion time associated with each identified contingent facility when this information is readily available and not commercially sensitive."[165] The Commission found that this information helps interconnection customers evaluate the risks associated with contingent facilities.[166] Transmission providers also have to post "interconnection study metrics to increase the transparency of interconnection study completion timeframes."[167] The Commission intended this requirement to help interconnection customers evaluate the time frame of the study process, and so that the Commission could detect and diagnose process deficiencies and their causes.[168]

To improve the interconnection process, the reforms aimed to better allocate interconnection service, completing interconnections earlier in time, and managing "changes in the development process."[169] To implement these tasks, the Commission permitted "interconnection customers to request interconnection service lower than the full generating facility capacity," and acknowledged "the need for proper control technologies and penalties to ensure that the generating facility does not inject energy above the requested level of service."[170] The interconnection customer is able to request lower service prior to the system impact study and prior to the facilities study.[171]

The penalties contemplated include "discrete financial penalties, a requirement to pay the cost of additional facilities or network upgrades, or the loss of interconnection rights."[172] However, the Commission opted to allow transmission providers to curtail interconnection service or to terminate the LGIA, finding these existing solutions to be sufficient to deter interconnection customer misconduct.[173] But the Commission did not foreclose the power to penal-

151. Order No. 845, Reform of Interconnection Procedures and Agreements, 163 FERC ¶ 61043, at 7 (2018).
152. *Id.* at 15.
153. *Id.* at 16.
154. *See id.* at 25.
155. *Id.* at 30.
156. *See id.* at 42-43.
157. *Id.* at 43.
158. *See id.*
159. *Id.* at 44.
160. *See id.* at 45.
161. *Id.* at 57-58.
162. *Id.* at 116.
163. *Id.*
164. *Id.* at 121.
165. *Id.* at 129.
166. *Id.*
167. *Id.* at 184.
168. *See id.* at 185-86.
169. *Id.* at 203.
170. *Id.* at 215-16.
171. *Id.* at 231.
172. *Id.* at 204.
173. *Id.* at 243.

ize. It left open the possibility that a transmission provider could make a §205 filing to propose penalties for interconnection customers.[174]

These steps improve flexibility for interconnection and accountability to optimize the use of transmission assets. To accomplish these reforms, the Commission also required the transmission provider to study interconnection requests at the level of service requested, but the Commission left it up to the transmission provider's discretion to study the interconnection at full generating capacity to ensure safety and reliability, with both study costs falling on the interconnection customer.[175] While this process change may deter generators from opting to use more facilities as they may have to bear the cost of an additional study for full generation capacity, the value of the additional study may reflect the value of allocating transmission resources efficiently and reliably.

Another reform that the Commission included in Order No. 845 was to require "transmission providers to establish an expedited process, separate from the interconnection queue, for the use of surplus interconnection service."[176] The purposes of this policy were to increase efficiency and reduce costs for interconnection customers by

> increasing the utilization of existing interconnection [infrastructure] . . . , improv[ing] wholesale market competition . . . through more efficient use of surplus existing interconnection capacity, and remov[ing] economic barriers to the development of complementary technologies . . . that may be able to easily tailor their use of interconnection service to adhere to the limitations of the surplus interconnection service that may exist.[177]

Additionally, other benefits include improving generation capabilities, avoiding stranded costs, and facilitating transmission system access.[178]

The Commission recognized that Order No. 2003 causes transmission providers to premise generation project approvals on the presumption that "generating facilities operate at their full capacity," but the reality is that generating facilities do not operate at full capacity at all times, causing unused capacity that would otherwise be available to other interconnection customers.[179] As a result, the Commission found it "unjust and unreasonable to deny an original interconnection customer the ability either to transfer or use for another resource surplus interconnection service."[180] However, to avoid perverse incentives and unintended consequences, the Commission limited use of surplus interconnection service "when new interconnection service would be more appropriate."[181] As a result, a retiring generation facility completely taken out of commercial operation would not be able to offer surplus interconnection capacity before the interconnection service customer's generation facility enters the market.[182]

Order No. 845 demonstrates that FERC continued facing the interconnection backlogs caused by Orders 2003 and 2006. The fact that these same issues inspired the rulemaking in June 2022 (discussed below) demonstrates that FERC has not yet found a solution to these problems. Some commentators speculate that "[l]ong queues will likely continue as long as transmission planning processes fail to proactively develop transmission capacity to serve remote high-quality resource areas."[183]

Cluster studies were a big part of the 2022 notice of proposed rulemaking (NOPR) (discussed below), but as FERC rejected their use in 2018, it shows that maybe FERC might have needed to use a heavier regulatory hand in setting its interconnection policy. FERC's hesitation shows it was aware that it was acting cautiously by choosing to avoid using cluster studies, but FERC returned to this tool four years later. It was caught in a predicament—the use of regulatory caution and restraint versus policy effectiveness. As FERC chose the path of caution, and while this was a rational decision, the gamble did not pay off, as we are still in need of regulatory reform. We can speculate that FERC perceived cluster studies to be a higher hanging fruit on the policy tree, and chose to implement less stringent regulatory options first, with the understanding that it could return to the regulatory drawing board later for adjustments.

Lastly, it is possible that FERC wanted to avoid employing the most stringent regulations in fear of congressional rebuke. Hence, this shows that FERC might need to adopt flexibility into its decisionmaking—it could promulgate a rule that it may perceive as costly and administratively difficult to implement, but allow regulated parties to have an adjudication to allow them to make the case that variance is needed and warranted by the facts and circumstances. Such a solution may be time-consuming and expensive for the Commission, but it would enable FERC to promote its regulatory objectives where it is most efficient to do so.

It is also an interesting set of policies to allow generators not to use capacity and then to allow transmission providers to set up a separate process for surplus capacity. Glick and Christiansen speculate that Order No. 845 aids the development of energy storage systems as interconnection customers can use "excess capacity to directly supply energy from other sources or transfer it to another resource."[184] While the impacts of this additional process may have eased the burden on the interconnection queue, an unintended consequence would have been to encourage interconnection customers to drop out of the queue to look at opportunities for a streamlined interconnection for the use of surplus capacity.

174. *Id.*
175. *Id.* at 222-23.
176. *Id.* at 277.
177. *Id.* at 277-78.
178. *Id.* at 278.
179. *Id.*
180. *Id.* at 281.
181. *Id.* at 282.
182. *Id.*
183. Rob Gramlich et al., Energy Storage Association, Enabling Versatility: Allowing Hybrid Resources to Deliver Their Full Value to Customers 8 (2019).
184. Glick & Christiansen, *supra* note 12, at 22.

However, it is unlikely that this speculative result actually happened. Surplus interconnection is temporary, and FERC thoughtfully considered when it was appropriate to enable its use. Because surplus capacity is generally predictable, it is desirable to make use of it as an asset, so that we can make greater use of the capacity that we have. What this discussion demonstrates is that FERC's regulations intended to ease burdens may have created other problems that exacerbate the underlying issues that FERC was trying to prevent. Every policy has an unintended consequence, and regulated parties can change their behavior in ways that undermine the effectiveness of desirable policies.

Additionally, this would be the logical place to summarize and discuss Order No. 2222, but this order was intended to address specific issues in the RTO/ISO market rules and their associated tariff regulations.[185] The Commission was not regulating an interconnection of specific projects on the queues of the RTOs/ISOs. Rather, it was contemplating whether or not to impose a standardized interconnection process for the "sales by distributed energy resource aggregators into the RTO/ISO market."[186] Later on, the Commission consciously decided not to do so, stating that this course of action would not be "necessary to advance the objectives of Order Nos. 2003, 2006 and 845."[187] Instead, the Commission left it up to the state and local regulators to deal with these types of interconnections.[188]

## VIII. The Latest Interconnection Initiatives

In this part, we will review some of the policies included in the 2022 NOPR, and then discuss Order No. 2023. By comparing the current rule to its proposed version, we can find differences that reveal new developments on FERC's regulatory strategy.

### A. *RM-22-14-000: The NOPR to Order No. 2023*

In June 2022, the Commission issued an NOPR announcing its intention to amend the interconnection procedures and agreements for large and small generators due to the interconnection queue backlogs and associated reliability issues.[189] The Commission's proposed reforms were grouped into three categories: those that implement a first-ready, first-served cluster study process; those that increase the speed of interconnection queue processing; and those that incorporate technological advancements into the interconnection process.[190]

In the first category, the Commission proposed "to revise the Commission's pro forma LGIP to require transmission providers to offer an informational interconnection study to serve as additional information for prospective interconnection customers in deciding whether to submit an interconnection request."[191] To prevent interconnection providers from becoming overloaded, to ensure that informational interconnection studies are obtainable by other interconnection customers, and to provide interconnection customers with an opportunity to explore alternative interconnection points, FERC proposed to limit interconnection customers to five informational interconnection study requests at a time.[192]

After receipt of a request for an informational study, the transmission provider would have seven business days to send the prospective interconnection customer a study agreement detailing the technical data that the interconnection customer would have to submit and the expected costs of the study.[193] In response, the interconnection customer would have 10 business days to provide the data, study deposit, and a signed agreement.[194] Then the transmission provider would have 45 days to complete the study.[195] The Commission also proposed to require transmission providers to post data visualizations on their available transmission capacity to remove the perverse incentive for interconnection customers to make requests as part of their information-gathering process for comparing alternative projects.[196]

The Commission also brought back the idea of cluster studies, which it previously rejected in Order No. 845. One part of the problem was that studying individual projects leads to identifying the upgrades that could accommodate the individual project. By studying interconnection requests together, the Commission hopes to facilitate fewer upgrades that would serve multiple projects, instead of multiple upgrades serving only a few projects.[197] Another part of the problem was that the Commission found that allocating the cost of network upgrades to the interconnection customer would cause a proposed interconnection project to be economically infeasible, despite the fact that the interconnection customer would later be reimbursed.[198]

As a result, the interconnection customer would withdraw from the queue, and the withdrawal would prompt restudy requirements for the lower-queued projects.[199] Then the transmission provider would place the burden of the network upgrade on subsequent interconnection customers in the queue, which might cause those customers to withdraw, along with more delays, higher costs, and more restudies.[200] Even worse, if an interconnection

185. *See* Order No. 2222, Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators, 172 FERC ¶ 61247, at 4-5 (2020).
186. *Id*. at 34.
187. *Id*. at 79.
188. *Id*. at 80.
189. FERC, Notice of Proposed Rulemaking, Improvements to Generator Interconnection Procedures and Agreements, 87 Fed. Reg. 39934, 39935 (July 5, 2022).
190. *Id*. at 39935 para. 4.
191. *Id*. at 39943 para. 42.
192. *Id*. at 39943 para. 43.
193. *Id*. at 39943 para. 44.
194. *Id*.
195. *Id*.
196. *See id*. at 39944 para. 49.
197. *See id*. at 39945 para. 54.
198. *Id*. at para. 55.
199. *Id*.
200. *Id*.

customer decided not to withdraw, but instead to incur the cost of the network upgrade, lower-queued customers would be able to freeride on the network upgrade as they "are not required to share cost responsibility simply because they submitted an interconnection request at a later date."[201] Thus, the goal of cluster studies is to increase efficiency in time and cost by preventing restudy requirements and by internalizing externalities in the cost allocation of network upgrades.

To implement cluster studies, the Commission proposed to amend the pro forma LGIP. Notably, interconnection customers must select a definitive interconnection point, that could be subject to changes by the transmission provider upon mutual agreement.[202] And interconnection customers would have 45 days to make an interconnection request to join the cluster (referred to as the "cluster request window").[203] All interconnection customers in the cluster would have equal queue priority.[204] However, earlier clusters would have a higher queue priority than later clusters.[205]

Following the cluster request window, the Commission proposed to have a 30-day "customer engagement window," where the transmission provider would conduct a scoping meeting with all of the interconnection customers in the cluster.[206] Interconnection customers could also request individualized, "customer-specific" scoping meetings within 15 business days of the start of the customer engagement window.[207] As a result of FERC's proposed reforms, the cluster study is a cumulative system impact study, that the "transmission provider must complete . . . within 150 days of the closing of the customer engagement window."[208] FERC also provided that the 150-day deadline would also apply to cluster restudies that might be caused by modifications or withdrawals of interconnection projects in the specific cluster or a higher cluster.[209]

To allocate the costs of the cluster studies, the Commission proposed to allocate 90% of the costs on a pro rata basis to account for the MW capacity of each project, and the remaining 10% of the costs would be allocated based on the number of interconnection requests in the cluster (the "per capita" basis).[210] For the cost of network upgrades, FERC proposed to allocate the cost based on proportional impact, but solicited comments on the methods used to calculate its value, along with the advantages and disadvantages of the method.[211] To address the freeriding problem of later interconnection customers benefitting from preexisting network upgrades paid for by earlier interconnection customers, the Commission also proposed to require transmission providers to allocate upgrade costs in a way to ensure that each customer pays for the proportion of benefits received, even if the interconnection customers are in different clusters that benefit from the same upgrade.[212]

Wrapping up the first category of reforms, the Commission's proposals took steps to "discourage speculative interconnection requests and allow transmission providers to focus on processing viable interconnection requests and to better approximate the cost of the interconnection study process."[213] These steps include increased study deposits, site control demonstration, commercial readiness demonstration or deposits, and withdrawal penalties.[214] The goal of these reforms is to encourage interconnection requests for more concrete projects, with higher likelihoods of commercialization, to create more certainty for the cluster while reducing speculation.[215] Finally, FERC proposed to require the transmission providers to establish a transition process so that they can start using cluster studies and wrap up the current studies for late-stage customers on the queues.[216] The framework for the valuation of the study deposits will be discussed later in this Article, when we review the changes between the NOPR and the final rule. However, a more detailed discussion of the Commission's site control and commercial readiness policies is intentionally omitted from this Article in the interest of brevity.

In the second category of reforms, aimed at increasing the speed of queue processing, the Commission found that the data collection required under Order No. 845 demonstrated that transmission providers nationwide were failing to complete the interconnection studies on a timely basis, as nearly 1,900 studies faced delays.[217] Reasons for the delays included "the high volume of interconnection requests, re-studies caused by withdrawal of higher-queued interconnection requests, and coordination among transmission owners, affected systems, and interconnection customers."[218]

The Commission found that transmission providers do not have any "meaningful" incentives to timely meet their deadlines for the completion of the interconnection studies and, hence, no accountability.[219] As a result, the Commission's first proposal under this category of reforms would set firm study deadlines and institute penalties for when transmission providers fail to meet them.[220] The proposed late fees are $500 per day after the deadline to be paid in the absence of a force majeure.[221] The Commission determined this amount to be consistent with penalties on interconnection customers, and sufficient to induce compliance without being "unnecessarily punitive."[222] After FERC collects the penalties, the penalties would be used to offset the

201. *Id*.
202. *Id*. at 39947 para. 66.
203. *Id*. at para. 67.
204. *Id*. at 39948 para. 67.
205. *Id*. at para. 70.
206. *Id*. at para. 68.
207. *Id*.
208. *Id*. at para. 74.
209. *Id*. at paras. 74-75.
210. *Id*. at 39949 para. 82.
211. *Id*. at 39950 para. 88.
212. *Id*. at 39951 para. 91.
213. *Id*. at 39952 para. 103.
214. *Id*. at 39953 para. 103.
215. *See id*. at para. 109.
216. *Id*. at 39960 para. 156.
217. *Id*. at 39961 para. 165.
218. *Id*.
219. *Id*. at 39961-62 para 167.
220. *Id*. at 39962 para. 168.
221. *Id*. at para. 169.
222. *Id*.

costs for the delayed interconnection customers on a pro rata basis, and transmission providers would be unable to recoup the penalties as a cost of service in rates.[223] FERC would also cap the penalties when the penalties equal the study deposit received, and would not assess the penalties until one cluster study cycle to ensure that the penalties are fair and efficient.[224]

If those provisions were not enough, FERC would also forgo assessment of the penalties when the amount of time for the delay is 10 days or fewer.[225] But on the 11th day, FERC would penalize the transmission provider from the first day of their delay. However, with the mutual agreement of all the interconnection customers in the cluster, the transmission provider could gain a 30-day extension and avoid all penalties.[226] However, the transmission provider would not be able to walk away scot-free. FERC would impose quarterly reporting requirements on the transmission provider so that they would have to disclose the total penalties paid in the previous quarter and the highest penalty amount for a single interconnection request in that previous quarter.[227] And in the implementation of the penalties, both RTOs and ISOs would be treated the same along with their profit-seeking counterparts.[228] However, FERC would permit the RTOs and ISOs to recover the penalties in their tariffs.

A second reform in the second category of combatting the queue delays would include steps to make the system study process more certain, clear, and transparent to interconnection customers.[229] The process is not consistent across any two transmission providers or even two interconnections handled by the same transmission provider. This problem causes interconnection customers to lack the cost data they may need to make informed decisions and complete the interconnection in time, and, consequently, they withdraw at a late stage and push costs down the queue.[230] As a result, FERC proposed to amend and expand the study process outlined in Order No. 2003 to include "initial notification, affected system scoping meeting, study process, cost allocation, study results and assessment, and financial penalties assessment."[231] Because transmission providers may have interconnected systems, an interconnection can have adverse impacts on other transmission providers that are not part of the deal.

The goal of the reformed process would be to increase coordination by requiring the transmission provider, within 10 business days, to notify the owners of an impacted system, as well as provide the interconnection customers with a list of potentially impacted parties.[232] Within 15 business days of receipt of the notification of an adverse system impact, the adversely impacted system would be required to respond in writing with a determination of whether it will perform its own study of its system.[233] If the affected system desires to conduct the study, within seven business days of its response, it would have to schedule an affected system scoping meeting, which would have to be held within seven days after it is scheduled.[234]

The scoping meeting's objective is to find ways to mitigate the impacts on the affected system, but not all parties would have to be present.[235] The interconnection customer would be required to attend, but not the initial transmission provider—the adversely impacted system would use "best efforts" to include the initial transmission provider.[236] Within five business days of sharing the schedule for the affected system study, the affected system would have to tender an affected system study agreement to the interconnection customer, and the interconnection customer would have 10 business days to execute and return the agreement.[237] And within 90 calendar days of receipt of the executed system study agreement, the impacted system would share the results of the study with the interconnection customer.[238] The results would include the estimated costs for the network upgrades, as well as the timing for their construction.[239]

After signing an affected system study agreement, the interconnection customer would join the queue of the affected system.[240] The interconnection customer's queue position in the affected system operator's queue would be determined by when it executed the affected system study, instead of when it joined the initial transmission provider's queue.[241] FERC explained that this new queue position "would be equivalent to that of a transmission provider's own interconnection customer that had just received its cluster study report."[242] Next, the affected system operator would be able to allocate the costs of needed upgrades using the proportional impact method.[243]

After completion of the affected system study, FERC would require the affected system to provide the interconnection customer with an affected system facilities construction agreement within 30 calendar days after providing the affected system study results. Then, the interconnection customer would go back to the initial transmission provider within five business days of receiving the interconnection agreement to inform the transmission provider if the interconnection customer will execute the affected system facilities construction agreement or request it to be filed unexecuted with FERC.[244] "The affected systems facilities construction agreement would be entered

223. *Id*.
224. *Id*. at para. 170.
225. *Id*.
226. *Id*.
227. *Id*.
228. *Id*. at para. 171.
229. *See id*. at 39965 para. 193.
230. *Id*. at 39963-64 para. 179.
231. *Id*. at 39964 para. 183.
232. *Id*. at para. 184.
233. *Id*. at para. 185.
234. *Id*. at 39964-65 para. 186.
235. *See id*. at 39965 para. 186.
236. *Id*.
237. *Id*. at para. 188.
238. *Id*. at para. 190.
239. *Id*.
240. *Id*. at para. 189.
241. *Id*.
242. *Id*.
243. *Id*.
244. *Id*. at para. 191.

into by the transmission provider acting as the affected system and the affected system interconnection customer."[245] Then, the transmission provider would manage the network upgrades, and the interconnection customer would initially fund the costs of the upgrades, but would later "be reimbursed by the transmission provider acting as the affected system."[246]

Next, FERC proposed to penalize affected systems for failing to comply with the deadlines for the process, but would hold the initial transmission providers harmless for late affected system studies and would not require them to wait for the results of the studies when conducting their cluster studies.[247]

In the third category of reforms, the Commission proposed reforms intended to incorporate technological advancements into the interconnection process.[248] The first subcategory of reforms would include policies aimed at increasing flexibility in the generator interconnection process. The first proposed policy was to allow interconnection customers to share an interconnection request when they co-locate generators behind a single interconnection point. This policy would account for hybrid projects with at least two different types of generation technologies, and streamline their study process to increase efficiency and accuracy for both the interconnection customers and the transmission provider.[249]

The second policy would modify the definition of a "material modification."[250] Various transmission providers implement the definition in different ways, causing some interconnection customers to lose their queue positions when they decide to add storage components onto their projects, even when the modification does not cause the requested transmission service level to change.[251] FERC found a need for uniformity to prevent "hinder[ing] access to the transmission system."[252] As a result, FERC proposed to require transmission providers to evaluate and study the impacts on system reliability, the requested level of interconnection service, and the equal and lower-queued projects before a transmission provider can determine that the modification is material.[253]

The third policy proposal was to change the implementation of Order No. 845's surplus interconnection capacity policy.[254] The Commission noted that Order No. 845 did not specify when an interconnection customer's surplus capacity becomes available, and many transmission providers assumed that it meant after the project becomes commercially operational.[255] Thus, FERC's proposal would clarify that the surplus capacity becomes available at the time of execution of the LGIA or filing of an unexecuted LGIA, to "enable interconnection customers with unused interconnection capacity to let other generating facilities use that capacity earlier than is currently allowed."[256]

The final proposal of the first subcategory would replace outdated assumptions used in interconnection studies with more realistic assumptions.[257] FERC would amend the LGIP to "require transmission providers, at the request of the interconnection customer [during the initial interconnection request], to use operating assumptions for interconnection studies that reflect the proposed operation" of the project.[258] However, the operating assumptions would need to be reasonably representative of the technologies employed, and "consistent with the historical performance of such resources in the relevant geographic area."[259] On the flip side, in the LGIA, the transmission provider would be able to bind the interconnection customer to operate according to the assumptions and require control technologies to be installed to ensure performance and accountability for breach.[260]

The second subcategory of proposed policies aims to employ new transmission technologies in the interconnection process.[261] The first policy included in this subcategory would require the transmission provider to assess alternative transmission technologies in interconnection studies if requested by the interconnection customer.[262] Based on the results of the studies, however, the transmission provider would be free to decide whether to employ the technologies requested.[263] Alternative transmission technologies would include "advanced power flow control, transmission switching, dynamic line ratings, static synchronous compensators, and static VAR [volt-ampere reactive] compensators."[264]

FERC found that the first three technologies can enable grid operators to optimize existing capacity by routing power around highly congested lines or inefficient lines caused by local weather conditions.[265] The last two technologies are additions to the grid that provide a consistent and continuous quantity of reactive power to the grid to ensure reliability.[266] The second policy FERC proposed would require transmission providers to report data to document whether and how they consider these technologies.[267]

In the third subcategory of reforms, the Commission proposed to impose modeling and performance requirements for asynchronous generators.[268] For the modeling requirements, the Commission is concerned that the inverters that asynchronous generators use have different

245. *Id.* at 39967 para. 202.
246. *Id.* at para. 202.
247. *Id.* at 39965 para. 192.
248. *Id.* at 39973.
249. *Id.* at 39974 paras. 242, 244.
250. *Id.* at 39974.
251. *Id.* at paras. 246, 252.
252. *Id.* at para. 254.
253. *Id.* at para. 255.
254. *Id.* at 39976.
255. *Id.* at 39977 para. 262.
256. *Id.* at para. 264.
257. *Id.* at 39977 para. 265.
258. *Id.* at 39979 para. 280.
259. *Id.* at 39979-80 para. 280.
260. *See id.* at para. 280.
261. *Id.* at 39981.
262. *Id.* at 39982 para. 297.
263. *Id.* at 39983 para. 299.
264. *Id.* at 39982 para. 298.
265. *Id.* at 39982-83 para. 298.
266. *Id.*
267. *Id.* at 39983 para. 302.
268. *Id.* at 39983.

electrical attributes than those used by synchronous generators and, hence, the models need more data inputs to become reliable and accurate.[269] Because the outputs of the models inform the needed network upgrades, the Commission is worried that the models will mislead the parties and lead to unsuitable upgrades, skewed costs, and problematic rates.[270]

### B. *Order No. 2023: Improvements to Generator Interconnection Procedures and Agreements*

In Order No. 2023, FERC continued to use the policy categories from the June 2022 NOPR. The three categories are: "(1) implement[ing] a first-ready, first-served cluster study process; (2) increas[ing] the speed of interconnection queue processing; and (3) incorporating technological advancements into the interconnection process."[271] To implement the first-ready, first-served cluster study process, FERC maintained the policies of adopting cluster studies, pro rata and per capita cost allocation (as discussed above), study deposits, site control demonstration, and withdrawal penalties.[272]

To speed up interconnection queue processing, FERC also kept the NOPR's late fees for transmission providers that fail to meet study deadlines as well as the NOPR's affected system study process and agreements.[273] The policies of enabling co-located facilities to use a single interconnection point and interconnection request; changing the definition of "material modification"; the change to the implementation of the surplus capacity market; the policy of evaluating various types of grid-enhancing technologies; and the policy of having interconnection customers provide data to the transmission providers for interconnection models all survived the comment period to form FERC's strategy to incorporate technological advancements into the interconnection process.[274]

While the final rule is closely derived from the NOPR, the Commission made some slight revisions to the cluster study process, cost allocation for cluster studies and network upgrades, study deposit increases, financial penalties for delays, the process for material modifications, and incorporation of grid-enhancing technologies.[275] And it "decline[d] to adopt the NOPR proposals pertaining to informational interconnection studies, shared network upgrades, . . . and the alternative transmission technologies annual report."[276] Note that this Article does not include a list of every single modification that FERC made between the NOPR and the final rule. The modifications listed above will be discussed in the order that they appear in the final rule, which does not correspond to the overview above. Moreover, this Article will only discuss modifications to the NOPR if they were previously covered here.

#### 1. The Abandonment of the Informational Studies Requirement

The Commission did not adopt the proposal for informational studies due to comments that raised unintended consequences of "divert[ing] the transmission provider's resources away from the cluster studies" that would undermine the efficiencies to be gained by the final rule's reforms.[277] Additionally, the informational study would not provide information that would be valuable enough to interconnection customers, due to the different assumptions of studying the impacts of the interconnection from the perspective of the larger cluster versus the individual customer.[278] Thus, the informational study would produce an inconsistent cost estimate that would be extraneous and superfluous after the cluster study.[279]

But recognizing that there is still a need for interconnection customers to have sufficient information before entering the queue to reduce speculation and exploratory interconnection requests, the Commission requires "transmission providers to publicly post available information pertaining to generator interconnection [on their Open Access Same Time Information System (OASIS)]."[280] The interconnection information is a "heatmap," which is an "interactive visual representation of available interconnection capacity."[281] The transmission providers must "update the heatmap within 30 calendar days after the completion of each cluster study and cluster restudy."[282] In addition, transmission providers must provide the following interconnection point data to interconnection customers:

> (1) the distribution factor; (2) the MW impact (based on the proposed project size and the distribution factor); (3) the percentage impact on each impacted transmission facility (based on the MW values of the proposed project and the facility rating); (4) the percentage of power flow on each impacted transmission facility before the proposed project; and (5) the percentage power flow on each impacted transmission facility after the injection of the proposed project.[283]

The Commission reasons that this information will enable interconnection customers to more effectively evaluate their proposed generation developments as the information will give interconnection customers more foresight on potential grid congestion and network upgrades that may be needed, which in turn will lead to less interconnec-

269. *Id.* at 39986 para. 318.
270. *Id.* at para. 319.
271. Order No. 2023, Improvements to Generator Interconnection Procedures and Agreements, 184 FERC ¶ 61054, para. 4 (July 28, 2023).
272. *Id.* at para. 5.
273. *Id.* at para. 6.
274. *Id.* at para. 7.
275. *Id.* at para. 9.
276. *Id.*
277. *Id.* at para. 89.
278. *Id.*
279. *See id.*
280. *Id.* at paras. 90, 91.
281. *Id.* at para. 94.
282. *Id.* at para. 135.
283. *Id.*

tion requests for non-commercial projects.[284] As a result, FERC projects that this reform will lessen withdrawals and delays.[285] As an ancillary benefit, the heatmap requirement is uniform across regions, making it easier for interconnection customers to make comparisons on the feasibility of different sites.[286] And the cost of implementing the heatmap is expected to be pretty low, as it requires an investment in new and available software that will enable the development of the heatmaps to be automated to reduce the financial burden on transmission providers.[287]

### 2. Some of FERC's Changes to the Cluster Study Process

One modification to the cluster study process that FERC made in the final rule involves the selection of a single, definitive point of interconnection.[288] In the final rule, the interconnection customers make the selection upon executing the cluster study agreement, so that the interconnection can include the proposed interconnection point in its interconnection request, take part in the customer engagement window, and obtain the results from the cluster study.[289] As a result, transmission providers are able to propose reasonable adjustments based on the transmission provider's extensive expertise of the transmission system, but the interconnection customer's consent is required.[290] The Commission is trying to enable the interconnection customers to have more evidence and flexibility in their decisionmaking without being able to cause delays, unnecessary burdens on transmission providers, and cluster restudies.[291]

Another modification to the cluster study process involves the "cluster request window" and the "customer engagement window."[292] The Commission increased the customer engagement window from 30 days to 60 days, and clarified the timeline for remedying deficiencies in interconnection requests.[293] Commenters revealed that 30 days was insufficient to effectively implement similar cluster study processes, so the Commission extended the customer engagement window to make it easier for transmission providers by granting them additional time to have individual meetings with interconnection customers.[294] On the flip side, interconnection customers have more time to evaluate their proposed projects and the composition of the cluster to decide whether or not to withdraw before facing a penalty.[295]

The Commission also decided not to extend the cluster request window.[296] When the cluster request window closes, the deadline to correct deficiencies passes, and if the interconnection customer does not respond to the requirement to respond to deficiencies during the customer engagement window, the interconnection request will be automatically withdrawn; the interconnection customer will forfeit the application fee to the transmission provider; and the transmission provider will return the interconnection customer's study and commercial readiness deposits.[297] FERC explains, "this provision is designed to ensure that interconnection customers and transmission providers have sufficient time to conduct scoping meetings and to discuss and comprehensively evaluate whether interconnection requests are fully valid during the customer engagement window."[298]

Within 10 business days of the customer engagement window, transmission providers must publish "new cluster information on their OASIS with details on each interconnection request for that cluster, including information on the amount of interconnection service and the location of the proposed generating facility . . . ."[299] Other information that must be provided in the OASIS postings includes the transmission line(s) for the interconnection; the projected date of operation; the type of interconnection service requested; and the type of generation project that will be constructed.[300] But the project information must be "anonymized" to protect sensitive information and ensure a level playing field.[301]

In addition, an interconnection customer is permitted to, and will not be penalized for, withdrawing its interconnection request during the customer engagement window.[302] However, after 46 calendar days after the transmission providers post the required information on their OASIS, the interconnection customers will not be able to withdraw from the cluster without paying the penalty.[303]

Another noteworthy revision to the cluster study process is that FERC chose to abandon the requirement of individual customer-specific scoping meetings at the interconnection customer's request.[304] The Commission found these types of meetings to be "[un]necessary to ensure that interconnection customer-specific questions are answered as interconnection customers consider whether to remain in the interconnection queue for the cluster study or to withdraw their interconnection request."[305]

284. *Id*. at paras. 136-137.
285. *Id*. at para. 137.
286. *Id*.
287. *See id*. at paras. 139, 140.
288. *Id*. at para. 200.
289. *Id*. at para. 201.
290. *Id*. at paras. 201, 203.
291. *See id*. at para. 202.
292. *Id*. at para. 204.
293. *Id*. at para. 223.
294. *Id*. at para. 233.
295. *Id*.
296. *Id*. at para. 225.
297. *Id*. at para. 226.
298. *Id*. at para. 234.
299. *Id*. at para. 232.
300. *Id*. at para. 237.
301. *See id*.
302. *Id*. at para. 232.
303. *See id*. at para. 233.
304. *Id*. at para. 245.
305. *Id*. at para. 246.

### 3. FERC's Modifications to the Cost Allocation of Cluster Study Costs

As discussed previously, the NOPR required 90% of the cluster study costs to be allocated on the pro rata basis (by each project's MW capacity) and the remaining 10% of cluster study costs to be allocated on a per capita basis (by the number of interconnection requests).[306] In the final rule, FERC enables transmission providers to offer its own cost allocation ratio between the pro rata basis and per capita basis, "provided that: between 10% and 50% of study costs must be allocated on a per capita basis, with the remainder (between 90% and 50%) allocated pro rata by MW."[307]

FERC's explanation for the policy change focused on how the 90%-10% formula concentrates the costs based on the size of individual projects within the cluster.[308] Because the formula focuses on the size of the project, a disproportionately sized project in the cluster skews the results of the formula, causing the formula to distort the cost allocation for the individual project.[309] Consequently, the interconnection customer would absorb a larger cost burden than necessary or a lower cost burden depending upon the size of the project in relation to the characteristics of the cluster.[310]

FERC also declares that "not all study costs track linearly with generating facility size because there are other factors . . . that can lead to increasingly complex studies and correspondingly higher study costs."[311] However, the pro rata basis and the per capita basis both address and simplify different systemic drivers of cluster study costs.[312] By accounting for both variables, the Commission is implementing cost-causation principles to arrive at just and reasonable rates and practices.[313]

### 4. FERC's Modification of Cluster Network Upgrade Costs

While FERC needed comments from the regulated community to develop the proportional impact method, it does little to devise the details for this cost allocation strategy in the final rule. The Commission's goals were to reduce freeriding on large network upgrade expenditures by later interconnection customers, to decrease the number of exploratory and speculative interconnection requests for projects that have no chance of commercial operation; and to remove the incentive for withdrawals from the queue.[314]

To accomplish these goals, FERC's first modification was to distinguish between substation network upgrades and system network upgrades. The Commission states, "the need for substation network upgrades is only generated by a specific generating facility seeking interconnection at a specific substation and not by all the generating facilities in the cluster."[315]

In other words, only the interconnection customers that benefit from a specific substation cause the cost of the upgrade, and other interconnection customers in the cluster may interconnect and benefit from other substations.[316] Thus, FERC separates substation network upgrades from more general system network upgrades and requires the costs of substation network upgrades to be paid by the interconnection customers that will connect behind the specific substation.[317] On the other hand, the cost of system network upgrades is incurred by all interconnection customers in a cluster, and is determined by the technical analyses chosen by the transmission provider according to its proportional impact method.[318]

The Commission notes that there are different types of network upgrades that can be categorized by their function, with their costs allocated using various methodologies.[319] As a result of this diversity and the different regional and local needs caused by the configuration of transmission providers' networks, as well as regional preferences for specific types of analyses, the Commission decided to require "transmission providers [to] provide tariff provisions that describe the method they will use for allocating costs of each type of network upgrade . . . ."[320]

### 5. FERC's Modification of Study Deposit Increases and Financial Penalties for Withdrawals

The NOPR proposed that the study deposit would incrementally increase with the size of the study deposit.[321] Projects less than 20 MW have no study deposit; projects between 20 MW and 80 MW have a study deposit equal to $35,000 plus $1,000 per MW; projects between 80 MW and 200 MW have a study deposit of $155,000; and projects that are more than 200 MW have a study deposit of $250,000.[322] In the final rule, FERC did not change these figures for the study deposits. However, it decided that transmission providers can assess the study deposits only at the time the interconnection customer submits an interconnection request and enters the cluster, as opposed to all phases of the cluster study process.[323] The tiered approach reflects the increasing costs of studies for larger project proposals.[324] And while these changes are small in number, it is significant that the policy rationale of the study deposits changed between the NOPR and the final rule, from being used as a tool to disincentivize interconnection requests to instead serving as a funding mechanism to ensure that the

306. *Id.* at para. 405.
307. *Id.* at para. 416.
308. *Id.* at para. 417.
309. *See id.*
310. *See id.*
311. *Id.* at para. 418.
312. *See id.*
313. *See id.*
314. *Id.* at para. 455.
315. *Id.* at para. 457.
316. *See id.*
317. *Id.* at para. 458.
318. *Id.*
319. *See id.* at para. 462.
320. *Id.* at paras. 462-463.
321. FERC, Notice of Proposed Rulemaking, Improvements to Generator Interconnection Procedures and Agreements, 87 Fed. Reg. 39934, 39953 para. 106; *id.* at para. 502.
322. Order No. 2023, 184 FERC ¶ 61054 at para. 502.
323. *Id.* at paras. 503, 506.
324. *Id.* at para. 504.

transmission providers have sufficient financial resources to conduct the cluster studies.[325]

FERC largely followed the NOPR to implement the withdrawal penalties. However, one place that the final rule deviated from the NOPR was where the Commission decided to change how to use the funds raised by the penalties. Generally, transmission providers will first use the funds to conduct the cluster studies for the cluster, and they will allocate remaining funds to offset increases to network upgrade cost assignments caused by the withdrawal.[326] However, under the circumstances that the withdrawal does not materially impact other interconnection customers in the cluster or queue, the transmission provider must return the withdrawal penalties that were not used for the cluster studies or cost increase offsets to the withdrawn interconnection customer.[327]

On the other hand, FERC changed the final rule by requiring the withdrawal penalty only in situations where the impact on other interconnection customers in the cluster or queue is material.[328] And there are other exemptions for an interconnection customer from the withdrawal penalty if the withdrawal is in response to substantial, unforeseeable, and unanticipated increases in the cost estimates of network upgrades.[329]

Another significant feature of the final rule is that FERC responded to the comments by adopting a withdrawal penalty structure that increases as the cluster moves through the cluster study process.[330] Under this fee structure, interconnection customers are incentivized not to remain in the queue as the damages of their lingering and later withdrawal accumulate. The fee structure is an effective deterrent against unwanted interconnection requests as it internalizes the negative externalities of withdrawal, while aligning the private interests of the specific interconnection customer with the common interests of the broader cluster and queue.[331] In addition, the Commission also removed the caps for the withdrawal penalties from the final rule to ensure that the incentive would be effective for interconnection customers with higher network upgrade cost assignments.[332]

### 6. The Final Rule's Changes to the Process for Making Material Modifications

FERC makes three key modifications to the NOPR's process in the final rule. The first change includes omitting the 60-calendar-day prerequisite for evaluating material modifications.[333] The rationale behind this change was to promote flexibility for transmission providers given their individual interconnection processes that would make it impractical to meet the 60-day deadline.[334]

The second change to the process restrains the regulatory burden on transmission providers by only requiring them to examine requests for additional generating facilities before the transmission provider receives the interconnection customer's executed facilities study agreement.[335] The purpose of this reform is to prevent requests for additional generating facilities from serving as an impediment to the transmission provider's ability to process the interconnection cluster and queue.[336] Instead of requiring the transmission provider to study these requests after the facilities studies agreement, the final rule leaves it up to their discretion.[337]

The final rule also changes course from the NOPR by instituting an "exception for transmission providers that use fuel-based dispatch assumptions . . . ."[338] Without the exception, the interconnection customer would lose their queue position, as a request for an additional generating facility will certainly be a material modification, which would trigger a new study to increase interconnection costs or impact the timing for the cluster and subsequent queue positions.[339]

### 7. Incorporating Grid-Enhancing Technologies

Another interesting way that the final rule differs from the NOPR is the final rule's inclusion of a wider and slightly different set of alternative transmission technologies. As previously discussed, the NOPR's proposal only included advanced power flow control, transmission switching, dynamic line ratings, static synchronous compensators, and static VAR compensators. The final rule includes all of the technologies listed above except dynamic line ratings, and adds "synchronous condensers, voltage source converters, advanced conductors, and tower lifting."[340]

FERC explains this decision by stating that it selected the technologies based on their potential to decrease interconnection costs for other types of network upgrades that would be time-consuming and capital-intensive.[341] And it found that dynamic line ratings would be more beneficial in the transmission operation and planning context rather than the interconnection context due to dependency on variable weather and transmission system conditions, while noting that transmission providers may still evaluate the use of dynamic line ratings for interconnection purposes during the cluster study.[342]

However, the Commission is not mandating the use of the grid-enhancing technologies, as it is technologically neutral. Instead, it is ensuring that the technologies are

325. *See id.* at para. 505.
326. *Id.* at para. 781.
327. *See id.* at para. 781.
328. *Id.* at para. 783.
329. *Id.* at paras. 784, 787.
330. *Id.* at para. 792.
331. *See id.* at para. 793.
332. *Id.* at para. 793.
333. *Id.* at para. 1406.
334. *See id.* at para. 1408.
335. *Id.* at para. 1406.
336. *See id.* at para. 1409.
337. *See id.* at para. 1410.
338. *Id.* at para. 1411.
339. *Id.*
340. *Id.* at para. 1578.
341. *Id.* at para. 1579.
342. *Id.* at paras. 1598, 1600.

considered alongside the network upgrades, and that the transmission provider makes the decision of how to proceed with modifying the infrastructure to accommodate the cluster's interconnections.[343] In addition, the transmission providers must assess the enumerated technologies during cluster studies and restudies, without a request from interconnection customers.[344]

The rationale for this modification was that it could have been incredibly burdensome and time-consuming for transmission providers to conduct the studies on an individualized basis, making it more risky that they would be unable to meet the deadlines of the cluster study process.[345] Criteria that guide the transmission providers in their decisions to employ the technologies includes "good utility practice, applicable reliability standards, and other applicable regulatory requirements."[346] And the transmission provider must explain the results of the assessment in terms of "feasibility, cost, and time savings as an alternative to a traditional network upgrade."[347]

## IX. Conclusion and Policy Recommendations

This Article reviews the major transmission and interconnection regulations of the past 27 years. It is beneficial to review FERC's regulatory journey to understand how our modern problems developed and how FERC is attempting to solve them. The survey demonstrates that the electricity market is constantly dynamic, and this dynamism causes FERC to regulate under constant stress from economic and technological change.

For example, technological developments as well as federal and state policies caused renewable energy resources to become cheaper and more widely used to generate electricity. These developments, in turn, caused FERC to standardize interconnection processes that later became dramatically backlogged. The 2022 NOPR and the final rule consider how various types of new generation and transmission technologies and practices impact the interconnection process, but these innovations were not contemplated at the time of FERC Order No. 2003.

It remains to be seen whether the reforms of Order No. 2023 will be successful at ensuring that we can interconnect generation facilities more quickly and cheaply, so we can lower the risks and costs to developers and transmission providers, avoid project cancellation, and ensure more effective grid planning. The 2022 NOPR and Order No. 2023 show that FERC is on the right track. The Commission has taken great efforts to engage in stakeholder outreach to generate a list of comprehensive solutions to the shortcomings of its previous regulations. It is noteworthy that Order No. 2023 passed with the approval of all four Commissioners, and survived the uncertainty of an evenly divided, politically split commission, after the U.S. Senate did not affirm Chairman Glick's renomination to serve on the Commission between the NOPR and final rule.

The fundamental problem of the interconnection queues was the lack of aligned incentives causing externalities on the participants in the queue. However, there is uncertainty regarding how the transmission providers will implement Order No. 2023, and consequently, it is anyone's guess as to whether the reforms will be effective. Stephen Hug, a partner at Akin Gump Strauss Hauer & Feld, speculates that the rule will not significantly reduce interconnection time for interconnection requests in regions that already employ cluster study processes.[348]

On the other hand, ClearView Energy Partners, a consulting firm in Washington, D.C., surmises that "FERC's interconnection reforms could resolve some of the planning challenges the electricity sector faces in handling the rapid growth of utility-scale renewable energy deployment," but that the final rule is not "revolutionary."[349] Dr. Johannes Pfeifenberger, one of the nation's leading experts on electricity market design, utility industry regulation, transmission, renewable generation and storage, and other areas, states "it is up to the grid operators to decide if they will comply with the order in a minimalistic fashion without meaningful improvements . . . or take it as an opportunity to make more holistic improvements that create a truly more efficient process."[350]

While the implementation of Order No. 2023 is yet to unfold, both interconnection customers and transmission providers, as well as the general electricity consumer and ratepayer, should support addressing its attempts at queue reform as opposed to a no-action scenario. The current grid backlogs show that there are new stresses on our electricity grid caused by state policies and technological development. These drivers of the need for reform adversely impact both interconnection customers and transmission providers, which means that there is an opportunity for a policy package that can meet the economic interests of all types of stakeholders.

Leaving the interconnection queue issues unchanged is also damaging to the vertically integrated utilities—while they may lose market share in the generation segment, they should be able to have more customers for their transmission services, and if they are worried about market share for generation, then they need to plan ahead, raise more capital for investment, and perhaps collaborate with independent power producers in the development of new generation so that they can remain competitive and relevant. Surely, the interconnection customers that overload the queue with requests and then prematurely withdraw are deserving of their fair share of the burden and blame for the current interconnection queue challenges. But competition works

343. *Id*. at paras. 1582, 1584.
344. *Id*. at paras. 1578, 1580.
345. *Id*. at para. 1590.
346. *Id*. at para. 1578.
347. *Id*.
348. Ethan Howland, *FERC Interconnection Rule May Not Speed Process in Much of US: Experts*, Utility Dive (Aug. 4, 2023), https://www.utilitydive.com/news/ferc-interconnection-queue-reform-spp-miso-pjm-rto/689965/.
349. *Id*.
350. Johannes Pfeifenberger, LinkedIn (Aug. 4, 2023), https://www.linkedin.com/feed/update/urn:li:activity:7093270127088947200/.

because it encourages efficiency, and if the vertically integrated utility cannot benefit from queue reform to add more of its own generation, then it is acknowledging that it is no longer an efficient electricity producer that is able to adapt to new circumstances in the power sector.

The cluster studies of the NOPR and Order No. 2023 should be effective when implemented in concert with the other reforms included. Because the cluster studies will be implemented to aggregate the interconnection customers together in a certain period of time, alongside the penalties to discourage and deter them from dropping out of the cluster, it is likely that FERC will have gone a long way toward putting a large subset of the interconnection queue issues to rest. However, it is clear that this rule is just one step toward fixing broader transmission system issues, as Acting Chairman Willie Phillips is contemplating a new rule to be released on transmission planning and cost allocation.[351]

While there may be different ways to allocate the cost of interconnection, what matters is that FERC has used its technical and economic expertise to ensure that its cost allocation decisions are just and reasonable.[352] As FERC has determined the variables to be used, allowed the transmission providers flexibility in determining how to weight the variables, and as the variables are simplifying systemic drivers of cost, the Commission is trying to further the principles of cost-causation to reach just and reasonable results. If successful, then the policies inherent in the cost allocation formula will effectively align the incentives of each queued participant in the cluster and enable a more efficient playing field as the externalities would be internalized.

If FERC's proposed penalties are later found to be ineffective at stimulating interconnection customers to remain in the queues, then the Commission will need to revisit the penalties to make them stronger and more deterrent. It is not a problem that a high withdrawal cost would disincentivize interconnection customers from entering the queue in the first place. Order Nos. 2003, 2006, 845, and 2023 each demonstrate that the causes of the backlog can be summarized as the use of outdated assumptions on the physics of generation and transmission driving a surplus of interconnection requests being made for the use of scarce capacity, alongside perverse incentives and unintended consequences, which in turn cause externalities and uncertainties.

A better process will not disincentivize new projects in the long term. Rather, it will make them more viable by aligning theory with practice to prevent external costs and delays from being pushed onto external actors. Such a reform makes the wholesale transmission market more just, reasonable, accountable, and transparent.

However, interconnection is just one piece of the transmission puzzle. In the future, the Commission should consider requiring transmission providers to complete short-term and long-term planning after each cluster of projects gets interconnected to the grid. The interconnection process will impact how many transmission assets we will need in the future to meet our decarbonization, energy security, and economic goals. Order No. 2023 only requires transmission providers to consider whether to employ certain grid-enhancing technologies. As FERC is technologically neutral, it will generally not mandate the use of these technologies unless it finds that the technologies are not used in the future, causing rates to be unjust and unreasonable.

If FERC does not mandate grid-enhancing technologies to be used, there may be a need for the U.S. Department of Energy to subsidize the use of grid-enhancing technologies to ensure that the technologies can be implemented. While the states may try to subsidize the use of these technologies, a court following *Hughes v. Talen Energy Marketing* might find that the states would be attempting to regulate the interstate wholesale transmission markets, which are under FERC's exclusive jurisdiction.[353] Ultimately, the more intensively we can use our existing capacity and transmission infrastructure, the less we will need to build new transmission infrastructure in the short term, invest in grid upgrades, and delay interconnections. Hence, the grid will be more resilient and better able to accommodate increasing demands and stresses.[354]

Despite the skepticism noted above, Order No. 2023 is a significant step toward achieving a more efficient interconnection process. And because transmission providers are required to study grid-enhancing technologies, transmission providers and system operators can gain further experience in using these technologies and developing best practices for their use. As a result, it is possible that grid-enhancing technologies can enable us to use our transmission assets more intensively.

For example, we can use software applications to reconfigure existing lines and networks to reduce transmission congestion; and there are technologies that use power flow routing to control the flow of electrons via physics of voltage and reactive power, which can enable transmission providers to actively manage the grid to prevent electrons from taking more congested paths on the network.[355] A 2021 study of these technologies in Kansas and Oklahoma found that grid-enhancing technologies can "enable more

351. Howland, *supra* note 348.
352. *See generally* Illinois Com. Comm'n v. Federal Energy Regul. Comm'n, 756 F.3d 556 (7th Cir. 2014); *see also* South Carolina Pub. Serv. Auth. v. Federal Energy Regul. Comm'n, 762 F.3d 41 (D.C. Cir. 2014).
353. 578 U.S. 150, 46 ELR 20078 (2016).
354. *See* Jay Caspary, *The Role For Grid-Enhancing Technologies*, Energy Sys. Integration Grp. (Jan. 27, 2022), https://www.esig.energy/the-role-for-grid-enhancing-technologies/.
355. Jeff St. John, *How to Move More Power With the Transmission Lines We Already Have*, Canary Media (July 29, 2022), https://www.canarymedia.com/articles/transmission/how-to-move-more-power-with-the-transmission-lines-we-already-have; *see also* U.S. Department of Energy, Grid-Enhancing Technologies: A Case Study on Ratepayer Impact (2022), https://www.energy.gov/sites/default/files/2022-04/Grid%20Enhancing%20Technologies%20-%20A%20Case%20Study%20on%20Ratepayer%20Impact%20-%20February%202022%20CLEAN%20as%20of%20032322.pdf; *see also* T. Bruce Tsuchida et al., Unlocking the Queue With Grid-Enhancing Technologies, Presentation Prepared for Working for Advanced Transmission Technologies Coalition 4 (Feb. 1, 2021), https://watt-transmission.org/wp-content/uploads/2021/02/Brattle__Unlocking-the-Queue-with-Grid-Enhancing-Technologies__Final-Report_Public-Version.pdf90.pdf.

than twice the amount of additional new renewables to be integrated," with an installation cost of approximately $90 million, $175 million in annual cost savings, nearly 12,000 jobs, three million tons of reduced carbon dioxide annually, and $47 million in other local economic benefits.[356]

Although the benefits outweigh the costs, grid-enhancing technologies are not in widespread deployment, because transmission providers are "not encouraged to deploy [these technologies] under cost-of-service ratemaking."[357] The reason for this perverse result is that conventional transmission lines are more capital-intensive, and investors get higher returns when rate base is larger.[358] This means the problem is that cost-of-service ratemaking is not currently accounting for performance optimization and efficiency. As a result, transmission providers should be allowed to have a separate rate base with a higher rate of return for these technologies allowed to incentivize deployment.

However, the rate of return should not be so high as to preclude consumers from sharing in the benefits of these technologies. It should still be a reasonable return on investment, but a return high enough to induce deployment of more efficient and better technologies. This can be comparable to a decoupling-plus policy for energy efficiency technologies,[359] which makes sense as both problems are manifestations of the Averch-Johnson effect.[360] Jay Caspary advocates for a similar policy of using cost-of-service regulation to achieve a rate that enables utilities and consumers to share in the benefits of cost savings.[361]

This is an acceptable, just, and reasonable solution: by using decoupling policies to promote grid-enhancing technologies, we can delay having to make larger investments in the current grid infrastructure, so that we can buy the time needed to go through the layers of administrative and technological processes that make it very cumbersome and challenging to build more transmission infrastructure.[362] In the short term, we can gain significant amounts of capacity to interconnect more alternative energy resources, protect system reliability, and reduce the long-term costs that ratepayers will bear as we transition the electricity grid for variable, distributed, and low-carbon energy resources. While short-term costs may rise for ratepayers and system operators, we can learn how to implement these technologies over time and reduce these costs. While it is understandable that FERC did not contemplate the use of ratemaking to encourage grid-enhancing technologies in Order No. 2023, such a discussion is worth consideration in a future rule on transmission planning and cost allocation.

And it is worth addressing the fact that FERC decided to remove dynamic line ratings from the list of enumerated technologies that transmission providers are required to study. National Grid, an electricity and natural gas utility that serves New York and Massachusetts, previously studied dynamic line ratings in its service territory. While National Grid's data show that the capacity that can be reached using dynamic line systems would be variable,[363] and this variability would presumably add costs for transmission providers to manage the grid, the costs associated with technological management issues should be tolerated, as the benefits outweigh the costs.[364]

Accordingly, FERC may have erred by removing dynamic line ratings from the list of enumerated technologies that transmission providers are required to evaluate. However, the mistake is not very significant as transmission providers may still assess and implement this option. Because FERC found the technology to be better suited for transmission planning, the technology should be considered again for that context and function. Alternatively, the technology can be considered as a way to bridge the gap between interconnection processes and planning processes between the short term and the long term.

In the June 2022 NOPR, FERC noted that the Edison Electric Institute raised concerns about the risks of deploying grid-enhancing technologies due to the potential for innovation and technological obsoletion.[365] While this counterargument raises a valid issue, the argument ignores ways that we can manage these risks or adapt to minimize them. Although technological and behavioral innovations may cause current technologies to be rendered inefficient in the future, our grid operators could inventory the most strategic through the least strategic (though still beneficial) places for grid-enhancing technology deployment, and save the most strategic locations for the future, when and where we can optimize the benefits of more efficient technology. Thus, the deployment of today's grid-enhancing technologies should be at suboptimal places on the grid so that we can get more field results and facilitate the learning needed to improve our current technologies and their implementation.

While there is a lack of experimental data on the performance of grid-enhancing technologies and their technological potential in the United States, we can look for opportunities to deploy the technologies, learn from their performance, and develop best practices. This is a lesson learned from the onshore and offshore wind industry—the most efficient sites with the highest capacity factors from higher wind speeds were the first to be used.[366] With proper

356. *See* Tsuchida et al., *supra* note 355, at 8-10.
357. *See* Caspary, *supra* note 354.
358. U.S. Department of Energy, *supra* note 355, at 9.
359. *See generally* Georgia Power Co. v. Georgia Indus. Grp., 214 Ga. App. 196, 199 (Ga. Ct. App. 1994) ("[A] utility may recover the actual or approved costs of its demand-side programs by passing along such costs directly to its ratepayers along with an additional sum or incentive (as determined by the Commission) to encourage it to develop such programs.").
360. Generally, the Averch-Johnson effect describes the unintended consequence that utilities would overinvest in the construction of assets to inflate rate base. It also describes the linkage between revenue and sales, and the resulting disincentives for energy efficiency. *See generally* Harvey Averch & Leland L. Johnson, *Behavior of the Firm Under Regulatory Constraint*, 52 Am. Econ. Rev. 1052 (1962).
361. *See* Caspary, *supra* note 354.
362. *See* Tsuchida et al., *supra* note 355, at 4.
363. St. John, *supra* note 355.
364. *See generally* U.S. Department of Energy, *supra* note 355.
365. FERC, Notice of Proposed Rulemaking, Improvements to Generator Interconnection Procedures and Agreements, 87 Fed. Reg. 39934, 39982 (July 5, 2022).
366. *See generally* U.S. Energy Information Administration, *Wind Explained: Where Wind Power Is Harnessed*, https://www.eia.gov/energyexplained/wind/where-wind-power-is-harnessed.php (last updated Apr. 20, 2023);

planning and evaluation of the technologies under various scenarios, we can take a measured approach to deploying grid-enhancing technologies for grid development so that we can avoid future inefficiency and a need for retrofits while benefitting from current technologies.

Lastly, if we could interconnect all of the projects in the interconnection queues in a timely manner, then we would have an additional 2,000 GW of capacity contributing to our wholesale electricity markets nationwide to power more than 484 million homes, which is more than three times the 142 million homes currently in existence.[367] The excess power produced by these projects could be applied to commercial buildings,[368] industrial processes that can be electrified,[369] and the transportation sector as electric vehicles penetrate the market.[370] As a result, the interconnection process and associated grid upgrades are crucial aspects of deep decarbonization, and currently serve as a significant barrier to these goals.

*see also* Walt Musial et al., NREL, 2016 Offshore Wind Energy Resource Assessment for the United States (2016), https://www.nrel.gov/docs/fy16osti/66599.pdf; *see also* U.S. Department of Energy, Staff Report to the Secretary on Electricity Markets and Reliability 77 fig.4.7 (2017), https://www.energy.gov/sites/default/files/2017/08/f36/Staff%20Report%20on%20Electricity%20Markets%20and%20Reliability_0.pdf.

367. U.S. Census Bureau, *supra* note 4.
368. *See generally* Jeff Deason et al., Lawrence Berkeley National Lab, Electrification of Buildings and Industry in the United States: Drivers, Barriers, Prospects, and Policy Approaches (2018), https://escholarship.org/content/qt8qz0n90q/qt8qz0n90q.pdf.
369. *See generally* Occo Roelofsen et al., *Plugging In: What Electrification Can Do for Industry*, McKinsey & Co. (May 28, 2020), https://www.mckinsey.com/industries/electric-power-and-natural-gas/our-insights/plugging-in-what-electrification-can-do-for-industry.
370. *See generally* Maximilian Fischer et al., *A Turning Point for US Auto Dealers: The Unstoppable Electric Car*, McKinsey & Co. (Sept. 23, 2021), https://www.mckinsey.com/industries/automotive-and-assembly/our-insights/a-turning-point-for-us-auto-dealers-the-unstoppable-electric-car.