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Research Brief

Regulation of Access, Pricing, and Planning of High Voltage Transmission in the U.S.

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The U.S. regulation of high-voltage transmission is highly complex and, as a result, generally poorly understood. This paper outlines the historical and regulatory evolution of the U.S. electric power system, focusing on generation, transmission, and distribution. It describes the transition from monopolistic utilities to a competitive market and the role of regulatory bodies like FERC. Key reforms, such as open-access transmission and nodal pricing, are highlighted. Challenges in transmission planning and generation interconnection processes are discussed, along with recent efforts to streamline them. Additionally, it touches on cost allocation methods and the determination of transmission rates. Providing a detailed account of the regulatory framework governing transmission access, transmission pricing, transmission planning and investment in the context of recent and expected future changes in the U.S. electricity sector.

We focus on the regulation of the transmission system by the Federal Energy Regulatory Commission (FERC) in the context of modern wholesale markets, the creation of Independent System Operators ("ISOs") and Regional Transmission Operators ("RTOs"), and the transition to a low-carbon or no-carbon electric power sector. The transmission system plays a key role in supporting the economic and reliable supply of electricity to end-use or retail customers.

The transmission grid is composed of several different types of transmission facilities that support different "needs" for transmission capability. Large high-voltage regional transmission facilities are the 'highway' for electricity. Connected to this "bulk-power" grid are lower-voltage transmission facilities that provide the necessary on-ramps for smaller generation facilities as well as off-ramps to enable delivery of wholesale power to local distribution systems. Significant investments in transmission have occurred throughout the United States in the last decade, with annual capital expenditures by FERC-jurisdictional transmission owners of \$20–25 billion since 2013.

The organization and regulation of the U.S. electric power sector has changed dramatically since its origins in the late 19th century but especially in the last 25 years. Historically, electric power systems are made up of three component parts: generation, transmission, and distribution, as shown in Figure 1. Large, utility-scale generators provide electric power by converting a fuel source, including the sun, wind, geothermal heat, nuclear fuel, run-of-river, or a wide array of fossil fuels, into electricity. Typically, this electricity is injected into the high-voltage transmission system, which is an interconnected network of power lines that transmits electricity over long distances within and between states. Finally, the distribution system receives this electricity from the transmission system and distributes it locally to end-use customers.

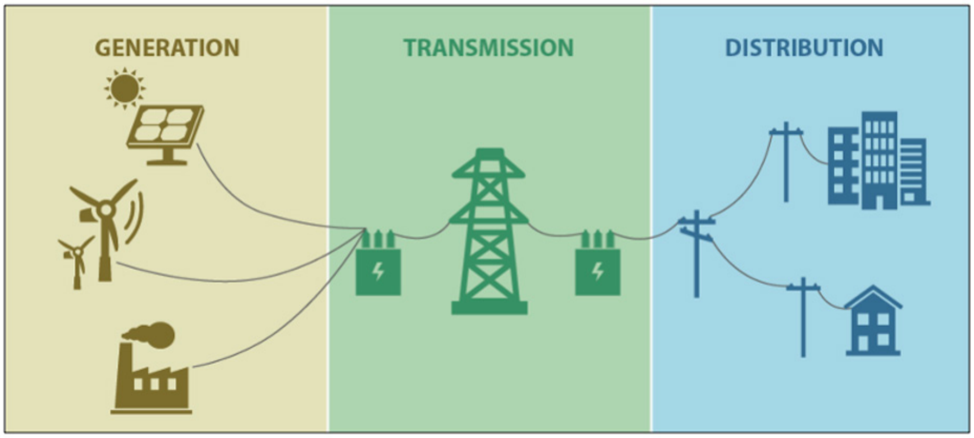

Figure 1. Electric Power System Overview
Source: Congressional Research Service, R45762 (August 4, 2022) at Figure 1.

The first Public Utility Commissions ("PUCs"), or state regulatory agencies with jurisdiction over electric and gas utilities, were founded in 1907, laying the foundation for more than two-thirds of U.S. states creating PUCs by 1920. From 1907-1920 while subject to constitutional restrictions imposed by the Supreme Court, states retained a large degree of autonomy even in creating policies that impacted neighboring states. In 1935 congress passed the Federal Power Act ("FPA") closing a gap in electricity regulation pertaining to matters remaining beyond the purview of state jurisdiction, and not yet covered by any federal law. The FPA placed under federal jurisdiction "the transmission of electric energy in interstate commerce" and "the sale of electric energy at wholesale in interstate commerce;"[1] requiring that all rates under federal jurisdiction be "just and reasonable" and not unduly discriminatory or preferential.[2] The FPA has since been subsequently amended but remains the main regulatory framework upon which the transmission regulations effective today were built.

Following the FPA's passage in 1935, federal jurisdiction expanded to include interstate transmission of electric energy.[3] The remaining components, "generation" and "distribution," as well as intrastate transmission, remained within state jurisdiction.[4] As a result, the dominant 20th century regulatory paradigm featured large, "vertically-integrated" utilities, regulated under state law with exclusive service areas and that typically owned all generation facilities sufficient to serve the retail customers within their geographic franchise areas or their "native" loads, and delivered the electricity largely through their own transmission and distribution networks. This framework largely resulted vertically-integrated utilities planning its own generation, transmission, and distribution facilities to serve the utility's "native load" customers—with only sales between utilities and third parties subject to federal jurisdiction.

This resulted in fairly limited federal involvement because only interstate transmissions of energy were regulated by the federal government through FERC; formerly the Federal Power Commission). It also is important to note that FERC jurisdiction over transmission and power markets does not extend to certain publicly owned power companies and federal power marketing agencies. FERC jurisdiction over transmission and electricity markets also does not apply to single-state power grids that are not synchronized with the interstate transmission network, such as the ERCOT managed grid covering most of Texas.

It was not until the 1990s, that some states sought to lower electricity rates by restructuring their utilities and creating organized competitive wholesale markets for electricity generation and related network support services.[5] Some "restructuring" laws allowed retail customers, for the first time, to choose an energy supplier (i.e., of generation services) other than their incumbent utility company. In many states, these same laws simultaneously required utilities to "unbundle" their generation assets from their existing utility business, creating a series of competitive independent generators and retail suppliers from which distribution utilities and retail customers could choose to set the framework for wholesale power markets in response to state restructuring efforts of the 1990s, a series of landmark FERC orders overhauled the method of using, selling, and planning transmission facilities in the U.S.[6] By applying the FPA's requirement of "non-discrimination" to the bulk transmission system, FERC set the foundation for the modern U.S. electricity industry, in which "open access" to the transmission system and lower-cost electric generation must be provided to all market participants, including competitive generators.

FERC issued **Order 888 in 1996**, the first of these landmark orders, just prior to the state restructuring reform efforts in the late 1990s.[7] The order transitioned the industry into a new open-access transmission paradigm, and away from the prior industry practice where each transmission owner controlled the use and assignment of available transmission capacity. This new "open access" framework provided non-discriminatory transmission system access to all market participants, with the goal to eliminate the ability for local utilities to provide preferential treatment to their own generation resources and setting the stage for a rapid growth in interstate trading of electricity.

In January 2000, FERC issued the (aptly-named) **Order 2000**, setting out minimum characteristics and functions necessary for ISOs and RTOs.[8] FERC promoted the creation of RTOs and ISOs to improve open access to the transmission grid envisioned through Order 888 and provide a framework and platform for newly deregulated utilities and generation companies to buy and sell electricity services in competitive wholesale power markets. FERC envisioned these RTOs/ISOs implementing organized wholesale power markets to replace the previous power pools of interconnected utilities that would rely solely on bilateral transactions.[9]

Each ISO/RTO has a well-defined geographic service area which can cover one state (e.g., New York) or multiple states (e.g., New England). Throughout their service area, RTOs/ISOs are granted responsibility for ensuring grid reliability. RTOs/ISOs are further responsible for operating the regional spot markets for electric energy, managing transmission congestion, and identifying and procuring the necessary "ancillary services" that are required to maintain grid reliability and the ongoing matching of generation and load.[10] Market monitors are tasked to ensure competitive outcomes and prevent manipulation of market prices or other types of fraud that would negatively impact electric ratepayers or other market participants. In addition to these market and operational functions, Order 2000 required RTOs/ISOs to take "ultimate responsibility" for transmission planning within their region.[11]

Less than 10 years after the issuance of Order 2000, FERC issued **Order 890** to further advance transmission reform.[12] These reforms set the underlying standards for transmission expansion planning processes used by all FERC-jurisdictional utilities today.[13] Notably, transmission planning processes were now required to include region-wide coordination,[14] early opportunities for open stakeholder and customer engagement[15] (including an opportunity to review the underlying assumptions relied on to plan transmission facilities)[16], and a method of regionally allocating the costs of resulting transmission projects.[17]

Less than five years following the issuance of Order 890, FERC sought to address identified shortcomings of regional RTO/ISO planning processes through the issuance of **Order 1000**.[18] The order required affirmative participation of transmission providers in developing regional plans with the participation of stakeholders and select the most efficient solutions available to solve identified regional transmission needs[19]—with the costs of these projects "allocated" to transmission customers throughout the planning region.[20] To introduce competition in the identification and selection of transmission projects, FERC removed the long-held federal "right-of-first-refusal" by incumbent transmission owners, enabling competitive transmission developers to bid on regionally-cost-allocated transmission expansions in competition with incumbent transmission owners.[21] Order 1000 also required that transmission plans address state and federal public policy needs.

The RTOs/ISOs have created and manage organized bid-based spot markets for wholesale power that integrates the management of transmission congestion with the determination of market clearing hourly day-ahead and real-time prices for energy. As a result, the organized wholesale energy markets in the U.S. lead to prices that may vary by location when there is congestion on the network. This system of location-specific pricing of electricity is called "nodal pricing" or Locational Marginal Pricing ("LMP") and forms the foundation for pricing electricity for all RTO/ISO markets in the U.S. Because higher LMPs are a direct result of insufficient transmission capacity, expanding transmission capacity to constrained areas will necessarily relieve the congestion, reduce wholesale LMPs, and make lower-cost generation accessible to customers. High observed or projected congestion costs on transmission paths between generation and load areas provides valuable information for transmission planning processes that are targeted to increase market efficiency and reduce total customer costs. Congestion costs observed in locational power markets are, however, an incomplete picture of transmission-related impacts on total electricity costs: they do not fully indicate the extent to which investment in additional transmission capacity can reduce wholesale power costs to balance supply and demand consistent with reliability goals, nor reflect public policy goals such as expanded supply of carbon-free generation while addressing resource adequacy and grid reliability challenges.

As required by FERC, transmission planning is supposed to address reliability, economic, and public policy needs.[22] In most regions, this means that separate planning processes are used to: (1) address local reliability-driven transmission needs; (2) enable the reliable interconnection of new generators; (3) reliably enable requests for long-term transmission service; (4) address region-wide reliability needs; (5) improve market efficiency (i.e., economic congestion relief) so lower-cost resources can be used to serve customers; (6) to address state or federal public policy needs; and (7) contemplate interregional transmission projects. As shown in figure 2, this leads to a siloed set of planning processes that address these various needs incrementally rather than holistically and is inefficient.

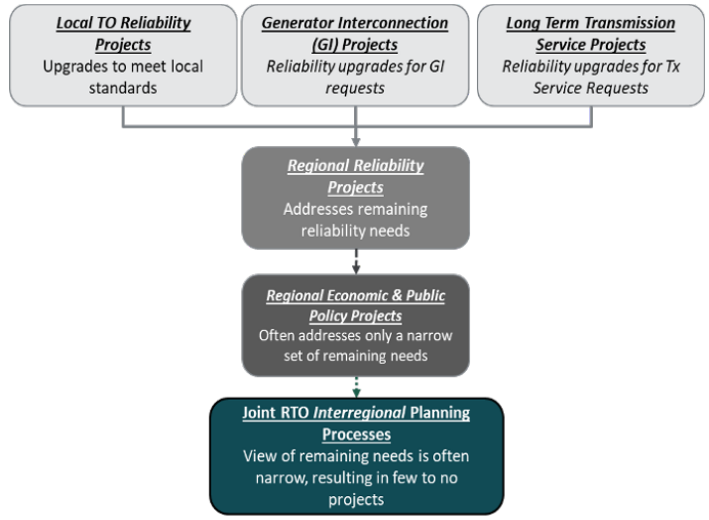

Figure 2. Typical U.S. Transmission Planning Process
Source: J. Pfeifenberger, The Benefits of Interregional Transmission: Grid Planning for the 21st Century (March 15, 2022) at 3 (with permission).

A number of **national transmission studies** have found that doubling or tripling the available regional and interregional transmission could provide significant cost savings and reliability benefits, particularly as the grid transitions to carbon free resources like wind and solar at geographic locations different from the bulk of thermal generators.[23] Expanding transmission nationally can also allow for the development of lower-cost carbon-free energy resources and delivering their output to load, diversity resource and load, increase system reliability and resilience, and offer a broader set of wholesale power market benefits. However, despite the net benefits of expanded interregional transmission demonstrated through these studies, they have failed to yield specific regional and interregional transmission expansion opportunities simply because the studies are misaligned with the transmission planning processes and geographic boundaries that are used by different ISO/RTOs.[24]

Certain transmission upgrades are necessary to enable the connection of new generating resources. These interconnection facilities include the transmission facilities between the generator and the closest transmission line or substation on the existing grid, which is called the "Point of Interconnection" ("POI"). Facilities between the generator and the POI are typically constructed by the generation project developer. By interconnecting its facility, the generator is seeking to inject power on the existing grid facilities owned by the local TO and the regional grid operator. Upgrades to the local grid around the POI may be necessary to accommodate the interconnection requests, the cost of which are typically assigned to the interconnecting generators.

The **generator interconnection** processes used by grid operators today were designed decades ago for the interconnection of a limited number of large generating plants. They are unable to handle quickly and efficiently the large number of interconnection requests today. As a result, generator interconnection queues have grown to levels that create long delays in realizing the necessary interconnection capacity and the associated development of new generating capacity.

To address the generator-interconnection-related delays, FERC issued Order 2023 in June of 2023.[25] With this order, FERC aims to streamline and speed up generator interconnection processes.[26] If actually implemented by grid operators, some of these reforms have the potential to significantly speed up generator interconnection processes, particularly at existing POIs and new POIs that do not require significant network upgrades—although additional reforms, such as integrating generator interconnection needs into more proactive and holistic transmission planning, will be necessary to achieve more timely and cost-effective outcomes.[27]

FERC has recognized that **holistic long-term transmission planning** is desirable to avoid the inefficiencies created by the siloed current planning processes.[28] Planning that holistically considers more than one transmission driver simultaneously is referred to as "multi-value" or "multi-driver" planning, enabling a single investment (a multi-driver solution) that can simultaneously and more cost-effectively address multiple needs. Holistic planning is particularly valuable now as the need to refurbish or replace transmission infrastructure originally deployed during the rapid expansion of the U.S. electric grid during the middle of the 20th century logically drives a significant portion of today's high level of local transmission investments. The large number of transmission facilities built in the 1950s, 1960s, and 1970s are now reaching the end of their useful lives and must be refurbished to maintain reliability. Through more holistic and forward-looking analyses, planners could evaluate a wide range of transmission needs, including local or asset replacement needs, and identify projects that can more cost effectively address the various types of transmission needs and better utilize the rights of way of aging existing lines.

The process used to set **transmission service** rates uses two steps: determining "revenue requirement" and then calculating the "transmission rate." FERC applies traditional cost of service regulation (COSR) or rate of return (ROR) regulation to determine the transmission revenue requirement, which is the annual amount of revenues that must be recovered from transmission customers to recover the full cost of transmission projects,[29] including capital and other development costs, operating and maintenance costs, taxes, and a FERC-allowed return of investment based on estimates of the TOs' cost of capital.

The revenue requirement is then allocated to transmission service customers to design a set of transmission service rates applicable to different types of transmission service. Precisely how the cost of regulated transmission facilities are allocated to utilities and users within a region typically varies by the type, driver, or voltage level of the transmission facility. A utility's own transmission costs and its share of allocated regional transmission costs are ultimately charged to loads in its service area. These transmission costs are then recovered from end-use customers through state-jurisdictional retail rates based on state-commission cost allocation rules.

FERC requires that the costs borne by different groups of ratepayers for each transmission facility are roughly commensurate with the benefits the facility provides to those customers.[30] In light of this standard, FERC and the courts have allowed for significant regional variation in the particular methods of identifying beneficiaries and allocating costs associated with facilities selected in the regional plan for purposes of regional cost allocation (pursuant to Order 1000).[31] The initial step of selecting a cost allocation method is mandated by Order 1000, as facilities cannot be selected in a regional plan without an approved regional cost allocation method for the particular type of transmission facility.[32]

Generally, cost allocation approaches tend to share the costs of regional projects more or less broadly throughout the region, for example based on variations in peak loads.[33] This tendency is enforced by recent court decisions, which have applied the cost causation principle in determining that large, high-voltage network transmission facilities provide regional benefits, limiting cost allocations that are too narrowly applied to only one set of customers.[34]

The process of determining wholesale or interstate transmission rates takes one of two forms: "stated rates" or "formula rates." The transmission-owning utility chooses which type of rate setting process it will use at FERC to determine its revenue requirements and associated transmission rates. FERC has expressed a preference for formula rates, noting that they encourage "certainty of recovery that is conducive to large transmission expansion programs."[35] As a result, most TOs utilize formula rates, particularly in ISO/RTO regions but also in areas outside organized wholesale markets.[36]

Stated rates require that a utility files a "rate case" with FERC under which rates are developed based on the current snapshot (or projected) revenue requirements. Once determined in the rate case, these rates then remain in effect until a new rate case is filed by the TO.[37] Under formula rates, a utility initially submits a spreadsheet template (the "formula"), designed as a framework to annually calculate updated revenue requirements. This template is subject to FERC review and approval when initially filed, similar to a typical change in a utility's Tariff. After this initial approval, the underlying formula remains unchanged (until the utility elects to change it). However, each year, the utility updates the formula rate "inputs," resulting in an annual update of its transmission revenue requirements and associated per-unit transmission rates.

As part of their jurisdiction over distribution utilities, states retain regulatory authority over the retail electric bills sent to end-use customers. While wholesale transmission service is FERC-jurisdiction, ultimately, the revenues and costs associated with transmission service provided and received pursuant to FERC-approved wholesale transmission rates must be recovered in state-jurisdictional retail rates paid by retail customers in various states. Because federal rates preempt state authority, and a state cannot limit recovery of a federally approved rate,[38] transmission charges are explicitly or implicitly included in every end-use customer's state-regulated electricity bill. While state regulators can participate in the transmission planning process and FERC transmission rate cases as stakeholders and retain authority to decide how transmission costs are recovered from different retail rate classes (e.g., commercial, industrial, residential, etc.), state utility commissions ultimately do not have the authority to disallow recovery of transmission costs approved by FERC.

References

Link to the full working paper discussed in this brief:

DeLosa III, Joe, Johannes Pfeifenberger, Paul L. Joskow (2024), "Regulation of Access, Pricing, and Planning of High Voltage Transmission in the U.S." MIT CEEPR Working Paper 2024-03, February 2024.

Citations:

1. 16 U.S.C. § 824(b).
2. 16 U.S.C. § 824d(a), (b).
3. *FPC v. Florida Power & Light Co.*, 404 U.S. 453, 461, 467 (1972) ("Power supplied to the bus from a variety of sources is said to merge at a point and to be commingled just as molecules of water from different sources (rains, streams, etc.) would be commingled in a reservoir") (citing 16 U.S.C. § 824(b)).
4. 16 U.S.C. § 824(b)(1) ("The Commission shall have jurisdiction over all facilities for such transmission or sale of electric energy, but shall not have jurisdiction, except as specifically provided in this subchapter and subchapter III of this chapter, over facilities used for the generation of electric energy or over facilities used in local distribution…").
5. Limited competition to utility-owned generation was previously facilitated in the late 1970s under the Public Utilities Regulatory Policy Act ("PURPA"), which allowed for certain small-scale third-party generation sold to utilities under regulated (avoided-cost-based) wholesale rates, see 16 U.S.C. Chapter 46. Similarly, prior to restructuring, markets consisting of bilateral wholesale power transactions existed throughout the U.S., going back to the early 20th century. See Joskow, P.L. and Schmalensee, R. (1983). Markets for Power: An Analysis of Electric Utility Deregulation, MIT Press. Cambridge, MA.
6. Many of the landmark orders use the federal "rulemaking" process which requires the Commission to provide adequate opportunity for public notice and comment. See *American Medical Ass'n v. Reno*, 57 F.3d 1129, 1132 (1995).
7. *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, FERC Stats. & Regs. ¶ 31,036, at 31,783-84 (1996) ("Order 888"), order on reh'g, Order No. 888-A, FERC Stats. & Regs. ¶ 31,048, *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part sub nom. Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC*, 535 U.S. 1 (2002). The Order was named after FERC moved into its new location at 888 First Street in Washington, D.C.
8. *Regional Transmission Organizations*, Order No. 2000, 65 FR 809 (Jan. 6, 2000), FERC Stats. & Regs. ¶ 31,089 (1999)("Order 2000"); *order on reh'g*, Order No. 2000-A, 65 FR 12088 (Mar. 8, 2000), FERC Stats. & Regs. ¶ 31,092 (2000), *aff'd sub nom. Public Utility District No. 1 of Snohomish County, Washington v. FERC*, 272 F.3d 607 (D.C. Cir. 2001).
9. Order 2000 at 14 ("Open access transmission and the opening of wholesale competition in the electric industry have brought an array of changes in the past several years: divestiture by many integrated utilities of some or all of their generating assets; significantly increased merger activity both between electric utilities and between electric and natural gas utilities; increases in the number of new participants in the industry in the form of both independent and affiliated power marketers and generators as well as independent power exchanges; increases in the volume of trade in the industry, particularly sales by marketers; state efforts to introduce retail competition; and new and different uses of the transmission grid"); see also National Association of Regulatory Utility Commissioners, National Regulatory Research Institute, A Review of FERC Order 2000 (April, 2000).
10. See FERC, *Energy Primer: A Handbook of Energy Market Basics*, (December, 2023).
11. Order 2000 at 485 ("We reaffirm the NOPR proposal that the RTO must have ultimate responsibility for both transmission planning and expansion within its region that will enable it to provide efficient, reliable and non-discriminatory service and coordinate such efforts with the appropriate state authorities").
12. *Preventing Undue Discrimination and Preference in Transmission System Service*, Order No. 890, FERC Stats. & Regs. ¶ 31,241 (2007) ("Order 890"), order on reh'g, Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 (2007), *order on reh'g*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g*, Order No. 890-C, 126 FERC ¶ 61,228, *order on clarification*, Order No. 890-D, 129 FERC ¶ 61,126 (2009).
13. Order 890 instituted nine principles for transmission planning processes: coordination, openness, transparency, information exchange, comparability, dispute resolution, regional coordination, economic planning studies, and cost allocation. Order 890 at PP 435–561. Note that "…to the extent that … asset management projects and activities do not expand the grid, they do not fall within the scope of Order 890," see 164 FERC ¶ 61,160 at PP 31–34 (2018).
14. Order 890 at PP 523–528.
15. Order 890 at PP 451–454.
16. Order 890 at PP 471–472.
17. Order 890 at PP 557–561.

18. *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, 136 FERC ¶ 61,051 (2011) ("Order 1000"), order on reh'g, Order No. 1000-A, 139 FERC ¶ 61,132, *order on reh'g and clarification*, Order No. 1000-B, 141 FERC ¶ 61,044 (2012), *aff'd sub nom. S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41 (D.C. Cir. 2014).
19. Order 1000 at P 331 ("Whether or not public utility transmission providers within a region select a transmission facility in the regional transmission plan for purposes of cost allocation will depend in part on their combined view of whether the transmission facility is an efficient or cost-effective solution to their needs").
20. Order 1000 at PP 482–779.
21. Order 1000 at PP 313–340. Historically, the incumbent (local) transmission owner would retain the rights to build all transmission facilities within its service territories under the federal right-of-first refusal. Order 1000 removed only *federal* rights-of-first refusal. Various state laws, undisturbed by Order 1000, effectively leave in place a right-of-first refusal in many states, even within RTO/ISO regions. See Order 1000 at P 287 ("The Commission acknowledges that there may be restrictions on the construction of transmission facilities by non-incumbent transmission providers under rules or regulations enforced by other jurisdictions. Nothing in this Final Rule is intended to limit, preempt, or otherwise affect state or local laws or regulations with respect to construction of transmission facilities, including but not limited to authority over siting or permitting of transmission facilities").
22. See Order 1000 at P 148.
23. See Table 1 in A Roadmap to Improved Interregional Transmission Planning and U.S. Department of Energy, National Transmission Needs Study (October, 2023), summarizing the results of several national studies undertaken in recent years by the National Renewable Energy Laboratory ("NREL"), M.I.T., and Princeton, among others.
24. As noted in A Roadmap to Improved Interregional Transmission Planning, these studies have not been successful in motivating improved interregional planning or actual transmission project developments because: (1) many of the national studies tend to analyze aspirational clean energy targets (e.g., 100% by 2050) not the actual policies for the next 10–15 years; (2) the studies do not identify specific transmission projects that could be built; (3) the studies fail to identify how benefits and costs are distributed across jurisdictions; (4) there has not been an analysis of the state-by-state economic impact and job creation from interregional transmission development; and (5) most studies do not propose solutions to address the barriers inherent in existing planning processes that stymie the development of new interregional transmission projects.
25. FERC, Improvements to Generator Interconnection Procedures and Agreements (July 28, 2023).
26. FERC, Explainer on the Interconnection Final Rule | Federal Energy Regulatory Commission (ferc.gov)
27. J. Pfeifenberger, How Resources Can Be Added More Quickly and Effectively to PJM's Grid (October 17, 2023).
28. See *Building for the Future through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, Notice of Proposed Rulemaking, 179 FERC ¶ 61,028 (2022); see also J. Pfeifenberger, R. Gramlich, et al., Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs (October, 2021).
29. Revenue requirements are often calculated for the entire group of a transmission owner's projects rather than for individual projects. Consistent with region-wide cost allocation frameworks, a transmission owner's revenue requirements may be the revenue requirements for all projects owned by the TO, plus payments to other transmission owners, less payments from other transmission owners in the region.
30. Supra nn. 37–40.
31. For a summary of regional cost allocations used by RTOs/ISOs, see Review of Regional Cost Allocation Methods, Organization of MISO States Cost Allocation Principles Committee (September 12, 2022) at pdf p. 7–24.
32. See Order 1000 at P 690 ("...a public utility transmission provider must have a regional cost allocation method for any transmission facility selected in a regional transmission plan for purposes of cost allocation. It may not designate a type of transmission facility that has not had a regional cost allocation method applied to it...").
33. Supra n. 91.
34. See *ODEC v. FERC*, 898 F.3d at 1261 (D.C. Cir. 2018) (overturning a FERC order that would have "shift[ed] a grossly disproportionate share of [the] costs of these high-voltage projects into a single zone") (internal citations omitted).
35. *Promoting Transmission Investment through Pricing Reform*, Order No. 679, 116 FERC ¶ 61,057 at P 386, n. 207 (2006) (*citing* approval of PJM Transmission Owner formula rates, 111 FERC ¶ 61,308 at P 51 (2005), 106 FERC ¶ 61,003 at P 32 (2004)).
36. For example, Black Hills, Basin Electric, and Powder River file a formula rate for service in Wyoming and South Dakota, see 148 FERC ¶ 61,035 (2014). Southern Company files a formula rate for service in Alabama, Georgia, and Mississippi, see 178 FERC ¶ 61,207 (2022).
37. See Cost of Service Rate Filings, FERC Staff. Stated rates are more often used outside of RTO/ISO regions, but also exist within RTOs/ISOs, such as in California where the TOs have agreed to update their transmission revenue requirement and associated rates every three years through the filing of a rate case with FERC.
38. See *Mississippi Power & Light Co. v. Mississippi ex rel. Moore*, 487 U.S. 354, 373 (1988), *citing Nantahala Power & Light Co. v. Thornburg*, 476 U.S. 953, 965-966 (1986) ("a state utility commission setting retail prices must allow, as reasonable operating expenses, costs incurred as a result of paying a FERC-determined wholesale price. . . . Once FERC sets such a rate, a State may not conclude in setting retail rates that the FERC-approved wholesale rates are unreasonable. A State must rather give effect to Congress' desire to give FERC plenary authority over interstate wholesale rates, and to ensure that the States do not interfere with this authority"). See also *Narragansett Electric Co. v. Burke*, 119 R.I. 559, 381 A.2d 1358 (1977), *cert. denied*, 435 U.S. 972 (1978); C. Hobelman, *The Narragansett Decision and its Aftermath*, Energy Law Journal, Volume 6:1.

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Joe DeLosa III is a Manager at The Brattle Group, with comprehensive experience at the intersection of state clean energy policy and wholesale electricity markets. He has served as a subject matter expert for senior decision-makers across a wide range of power market issues, including cost-effective implementation of state clean energy policy, resource adequacy, transmission planning, energy and reserve markets, demand response, financial transmission rights, energy efficiency, and energy storage. Mr. DeLosa has offered expert guidance on major state policy initiatives, including PJM's inaugural State Agreement Approach for integrating offshore wind, integrated distribution planning, transmission cost allocation, and retail rate design.

Before joining Brattle, Mr. DeLosa was the Bureau Chief of Federal & Regional Policy at the New Jersey Board of Public Utilities, where he managed all RTO and federal affairs for the State. In his prior role, he also oversaw regional regulatory affairs for the Delaware Public Service Commission. He has also advised a wide range of PJM States as a long-time member of the Organization of PJM states (OPSI) staff.

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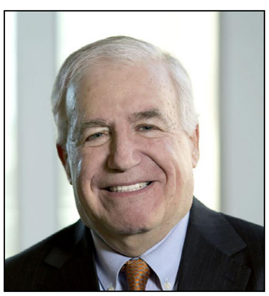

Paul L. Joskow is the Elizabeth and James Killian Professor of Economics, Emeritus at the Massachusetts Institute of Technology (MIT) and President, Emeritus of the Alfred P. Sloan Foundation. Joskow has been on the MIT faculty since 1972, where he was the head of the MIT Department of Economics from 1994 to 1998 and director of the MIT CEEPR from 1999 to 2007. Joskow became president of the Sloan Foundation in 2008 and returned to MIT in 2018. At MIT his teaching and research areas include industrial organization, energy and environmental economics, competition policy, and government regulation of industry. He is a past-president of the International Society for New Institutional Economics, a distinguished fellow of the Industrial Organization Society, a distinguished fellow of the American Economic Association, a fellow of the Econometric Society, a fellow of the American Academy of Arts and Sciences, a fellow of the Econometric Society, and a member of the Council on Foreign Relations. He has served on the boards of the New England Electric System, National Grid PLC, TC Energy, State Farm Indemnity, Exelon Corporation, Putnam Mutual Funds, and the Whitehead Institute for Biomedical Research (current).

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