TOWARDS A NATIONAL TRANSMISSION PLANNING AUTHORITY

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This Article explains why U.S. electric utilities are overinvesting in small, local transmission projects and underinvesting in high-voltage regional and interregional lines that would reduce congestion, improve reliability, and support state and federal decarbonization goals. The first problem is that state and federal policies create financial incentives for utilities to avoid investing in regional and interregional projects, as small lines are often exempt from rules that otherwise require competitive procurements, protect the market power of vertically integrated utilities' generation assets, and are subject to little, if any, regulatory review. The second problem is that federal regulations put utilities in a position to direct investment towards projects that protect their own interests but do not promote the general welfare. Utilities influence investment decisions both by developing the criteria to determine whether certain projects—especially reliability projects—should be constructed, and by using their governance rights to shape regional transmission policy. The result is a regulatory environment that outsources—perhaps inadvertently—responsibility for transmission planning to utilities that have both the incentive and the ability to channel investment towards projects that avoid competition, protect their generators' market power, and evade regulatory oversight. We conclude by proposing solutions that state and federal regulators could implement under current legal authority and others that would require new legislation.

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Introduction

Transmission investment in the United States is failing to keep pace with the country's electricity needs.[1] This is occurring despite the fact that U.S. electric

1. Insufficient investment in high-voltage transmission projects is reducing the reliability of the U.S. electric system, impeding with economic growth, and hindering state and federal efforts to reduce carbon emissions. A lack of investment in regional and interregional lines, particularly during severe weather events, reduces system reliability by increasing the risk of catastrophic blackouts. It also impedes economic growth, as additional transmission capacity is also required to meet the enormous energy demands of new data centers. Finally, the current shortage of regional and interregional transmission infrastructure hinders efforts to

utilities spend a great deal of money on transmission every year,[2] and despite decades of reforms aimed at improving the processes for planning, permitting, and paying for new transmission projects.[3] As we show, the reason utilities are able to avoid federal transmission planning requirements is that regulatory loopholes allow them to direct investment towards small, local projects.[4] While local projects may respond to the individual needs of customers in utilities' local service territories, they are unlikely to be the most cost-effective way of improving grid reliability, integrating zero-carbon resources, and accommodating expected load growth. Consider a few examples:

- New projects are supposed to go through regional and interregional planning processes to make sure that new investment cost-effectively addresses regional and interregional transmission needs. In Ohio alone, since 2017, utilities have received approval to spend more than $6 billion on supplemental projects that do not go through the regional or interregional planning processes.[5] These lines are not subject to competitive solicitations, and they are able to proceed with virtually no oversight about whether the investment is prudent.[6] Ohio is not an outlier. In one regional transmission organization (RTO)—Pennsylvania-New Jersey-Maryland Interconnection ("PJM")—73% of transmission spending between 2014 and 2021 went to supplemental projects, up from just 9% between 2005 and 2013.[7]

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reduce carbon emissions by limiting the ability of solar and wind resources to deliver electricity to high-demand areas. *See infra* Section I.

2. Between 2000 and 2019, transmission investment ballooned from $9.1 billion to $40 billion a year. These figures adjust for inflation. *See* U.S. Energy Info. Admin., *Utilities continue to increase spending on the electric transmission system* (Mar. 26, 2021), https://perma.cc/S8LK-W6NZ.
3. For example, in 2021, Congress passed the Infrastructure Investment and Jobs Act (IIJA), which increased federal financial support for transmission investment. A year later, Congress passed the Inflation Reduction Act (IRA), which provided additional support for new transmission investment. Then, in 2023, the Federal Energy Regulatory Commission (FERC) issued two Orders—Order No. 1977 and Order No. 1920—to improve processes for siting, planning, and allocating the costs of new transmission. But these reforms date back decades. For a more detailed history of federal efforts to encourage coordinated transmission planning, *see infra* Section II.
4. For the last decade, this process has been governed by Order No. 1000, which mandated a regional, competitive transmission planning process. *See* 76 Fed. Reg. 166, 49854. Once Order No. 1920 goes into effect, transmission owners will also be required to consider at least seven types of benefits of transmission and use a beneficiary pays approach to cost allocation. *See infra* Section III.A.
5. Pl.'s Compl., *The Office of the Ohio Consumer's Counsel v. PJM Interconnection, LLC*, FERC Docket No. EL23-105-000, at 2 (Sep. 28, 2023).
6. *Id.* at 4.
7. Claire Wayner, *Increased Spending on Transmission in PJM – Is it the Right Type of Line?* Rocky Mountain Inst., https://perma.cc/M94S-TYXF (Mar. 20, 2023).

- FERC requires that most regionally-planned lines be selected through a competitive bidding process.[8] Yet incumbent transmission owners use carve-outs to the competitive process to avoid being forced to compete with other transmission developers. Consider, for example, asset condition and asset management projects in the Independent System Operator of New England ("ISO-NE"). These refer to investments that are needed to repair degraded lines or make upgrades to support system reliability.[9] Although these projects are technically part of ISO-NE's regional plan, they do not undergo competitive solicitations, and transmission owners develop the criteria to determine whether these investments should be made. As of 2023, ISO-NE transmission owners planned to spend approximately $5 billion on asset condition projects.[10] In the country as a whole, just 3% of transmission projects are actually subject to competitive solicitations.[11]
- States are often thought to review new transmission investments to make sure that developers consider cost-effective alternatives and minimize adverse impacts on the community. Yet most states exempt low-kV lines and lines built on existing rights of way from state and local permitting requirements,[12] allowing utilities to minimize state-level review by directing investment to small projects and upgrades to existing lines.

This Article explores the state and federal policies that create suboptimal incentives for transmission owners, argues that regulators should play a larger role in siting, planning, and allocating the costs of large-scale transmission investment, and explains how they can do so both under current legal authority and through legislative reforms. The central problem, we argue, is that the

8. *See* FERC Order No. 1000, Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities, 76 Fed. Reg. 49,842 (Aug. 11, 2011) (revising 18 C.F.R.§ 35) (2011) (requiring the removal of federal rights of first refusal from Commission-approved tariffs; suggesting, but not requiring, that projects be selected through a competitive bidding process); *See*, *e.g.*, *The Competitive Planning Process*, PJM, https://perma.cc/7HLE-ZAS5; *Competitive Transmission*, ISO New Eng., https://perma.cc/QCL3-ZC2W.
9. *See* ISO-NE, Transmission Owner Asset Management, https://perma.cc/9R5B-RLLA; New England Transmission Owners, Joint New England Transmission Owner Asset Condition Process Guide (Apr. 25, 2024), https://perma.cc/JNX9-AATX.
10. *See* Letter From New England Consumer Advocates to ISO-NE Planning Advisory Comm. 1 (Sept. 14, 2023), https://perma.cc/F8C7-958H ("[W]e understand that there are approximately $5 billion in 'asset condition' projects currently proposed, planned, or under construction—an amount that increased by 50% within the last 6 months.").
11. Jim Rossi, *The Costs of "Crony Capitalism" in Regional Transmission Grid Expansion*, 36 Elec. J. 107335, 3 (2023).
12. *See, e.g.*, Cal. Pub. Util. Comm'n, Rules Relating to the Planning and Construction of Electric Generation, Transmission/Power/Distribution Line Facilities and Substations Located in California, General Order No. 131-D § III (Dec. 14, 2023) (exempting transmission lines operating below 50kV from requiring a CPCN).

current regulatory landscape gives incumbent utilities a financial incentive to avoid investing in high-voltage lines while also giving them significant discretion to determine which lines will be built. Here we build on work by Steve Cicala, Jacob Mays, Catherine Hausman, Ari Peskoe, and others who have identified many of the challenges we discuss.[13] Our hope is to provide a comprehensive account of permitting, planning, and cost allocation rules across the country to show that the United States has outsourced—perhaps inadvertently—primary responsibility for planning new transmission to incumbent transmission owners, who use exemptions to the regional process to avoid competition, protect their generators' market power, and avoid regulatory scrutiny.[14]

We further argue that utilities' misaligned incentives suggest that the federal government needs to take a more proactive role in planning, permitting, and assigning the costs of new transmission lines, and we explain how the federal government can use existing regulatory authority to rationalize transmission investment. To that end, we propose that FERC and the Department of Energy adopt the following reforms:[15]

- Leverage the Grid Deployment Office's statutory authority to both fund and site high-voltage regional transmission lines.
- Direct incumbent utilities to develop new transmission infrastructure to connect renewable generation units to the grid under § 202 of the Federal Power Act ("FPA").

13. *See* Steve Cicala, *Restructuring the Rate Base* 2-3 (Oct. 19, 2022), https://www.stevecicala.com/papers/restructuring_rate_base/restructuring_rate_base_draft.pdf (finding that utilities in restructured markets increased spending on rate regulated transmission and distribution assets); Catherine Hausman, *Power Flows: Transmission Lines, Allocative Efficiency, and Corporate Profits*, at 32–33 (NBER, Working Paper 32091, 2024); *See* Dasom Ham, Owen Kay, & Catherine Hausman, Power Flows Part 2: Transmission Lowers Generation Costs, But Generator Incentives Are Not Aligned (Dec. 2024) (manuscript on file with authors); Ari Peskoe, *Is the Utility Transmission Syndicate Forever?*, 42 Energy L. J. 1, 35 (2021); Ari Peskoe, *Replacing the Utility Transmission Syndicate's Conrol*, 44 Energy L. J. 547, 556-67 (2021); Joshua C. Macey & Aneil Kovvali, *The Corporate Governance of Public Utilities*, 40 Yale J. Regul. 569, 574 (2023) (describing how the characteristics of rate-regulated utilities explain their misaligned incentives vis-à-vis the public at large); Joshua C. Macey, *Outsourcing Electricity Market Design*, 91 U. Chi. L. Rev. 1243 (2024); Joshua Macey & Jacob Mays, *The Law and Economics of Transmission Planning and Cost Allocation*, 42 Energy L. J. (forthcoming 2024); Han Shu & Jacob Mays, *Transmission Benefits and Cost Allocation Under Uncertainty*, 141 Energy Econ. (2024).
14. *See* Ari Peskoe, *Can FERC Convince Utilities to Build Modern Transmission Systems*, Harvard Env't. Energy L. Program (May 4, 2022), https://perma.cc/CZ4Y-KXX7; Frank A. Wolak, *Regulating Competition in Wholesale Electricity Supply*, in Economic Regulation and Its Reform: What Have We Learned?, ed. Nancy L. Rose 217 (2014) ("[T]he market power that an electricity supplier possesses fundamentally depends on the size of the geographic market it competes in, which depends on the characteristics of the transmission network and location of final demand.").
15. *See infra* Section IV (discussing proposed reforms and solutions).

- Use existing federal studies such as the Department of Energy's Transmission Needs Study,[16] the Department of Energy's National Transmission Planning Study,[17] and the North American Electric Reliability Corporation's Interregional Transfer Capability Study to identify transmission solutions.[18]
- Force transmission owners to provide equal access—as opposed to merely equal rates—to their transmission lines.
- Order incumbent utilities to remedy existing failures to construct regional transmission under §§ 205-206 of the FPA.
- Aggressively designate areas as National Interest Electric Transmission Corridors ("NIETCs"), and use FERC's backstop siting authority to site additional transmission lines under § 216 of the FPA.
- Create a National Transmission Planning Authority to conduct coordinated *interregional* planning in ways that RTOs are currently not willing or able to.
- Reform governance of RTOs and other transmission planning entities to reduce the ability of incumbent utilities to control transmission planning.
- Redesign formula rates to incentivize the development of lines that generate tangible benefits for ratepayers.
- Grant filing rights to parties beyond just utilities to avoid the asymmetrical review burden faced by FERC under § 205 and § 206 (may require new legislation).

Although these reforms would go a long way towards rationalizing transmission investment, legislative reforms would be helpful in further improving incentives to make cost-effective transmission investments. To that end, we propose that Congress enact the following laws to further support investment in high-voltage lines:

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16. *See* U.S. Dep't of Energy, National Transmission Needs Study v–vi (2023) (showing areas where transmission congestion is leading to high prices), https://perma.cc/7LZC-B698.
17. *See* U.S. Dep't of Energy, National Transmission Planning Study, Chapter 1: Introduction 2–3 (2024) (describing benefits of transmission expansion under different scenarios); U.S. Dep't of Energy, National Transmission Planning Study, Chapter 3: Transmission Portfolios and Operations for 2035 Scenarios ix–xii (showing potential transmission portfolios).
18. *See* Fiscal Responsibility Act of 2023, Pub. L. No. 118–5, § 322, 137 Stat. 10 (2023) (requiring NERC to "conduct a study of total transfer capability . . . between transmission planning regions" that includes, among other things, "[a] recommendation of prudent additions to total transfer capability between each pair of neighboring transmission planning regions that would demonstrably strengthen reliability within and among such neighboring transmission planning regions").

- Increase FERC's authority to modify rate proposals and direct investment towards lines that reduce congestion, improve reliability, and support state and federal decarbonization policies.
- Increase financial support for high-voltage lines, possibly through additional appropriations for the Grid Deployment Office.
- Mandate beneficiary-pays cost allocation for all transmission projects and establish clear guidelines as to what benefits should be taken into account.
- Expand FERC siting and permitting authority.

This Article proceeds in four Parts. Section I provides an overview of the need for high-voltage regional and interregional transmission lines. Section II describes laws and regulations that are intended to lead to coordinated regional and interregional planning processes in which new lines are assigned to developers based on competitive solicitations. Section III explains why the current transmission planning process is not producing cost-effective transmission solutions. Section IV suggests legislative and regulatory reforms that would support more efficient investment in the transmission system.

I. The Benefits of Transmission

Additional investment in high-voltage regional and interregional lines would provide significant benefits to the U.S. economy, lowering electricity bills, reducing emissions, and supporting system reliability.[19]

The economic costs of transmission failures are enormous. Power outages cost the U.S. economy some $150 billion annually, not accounting for the very real human toll of outages.[20] In the coming years, transmission performance is expected to get even worse due to a combination of aging infrastructure, increasingly severe weather events, and growing demand for electricity.[21]

19. *See* Dep't of Energy, National Transmission Planning Study – Conclusions 2–4 (describing cost savings and reliability improvements resulting from transmission investments); An estimated $200-400 billions of investment is required by 2030 in order to support the high-voltage transmission demands of an electricity network that attains carbon neutrality by 2030. Eric Larson et al., *Net-Zero America: Potential Pathways, Infrastructure, and Impacts Final Report*, Net Zero America 108 (Oct. 29, 2021), https://perma.cc/F9CQ-6EM5. *See also* Lucas W. Davis et al., *Transmission Impossible? Prospects for Decarbonizing the US Grid*, 37 J. Econ. Persp. 155, 165 (2023) (summarizing different transmission investment capacity need estimates).

20. *U.S. Department of Energy Announces $48 Million to Improve Reliability and Resiliency of America's Power Grid*, U.S. Dep't of Energy (Feb. 24, 2023), https://perma.cc/Y9Q2-28LE.

21. *See, e.g.*, Alex de Vries, *The growing energy footprint of artificial intelligence*, 7 Joule 2191, 2192-93 (2023) (estimating LLM server energy use at between 85.4-134.0 TWh by 2027, up from an estimated 5.7-8.9 TWh in 2023).

From an emissions standpoint, transmission is important because the best wind and solar is typically far from areas of the country that consume large amounts of electricity.[22] Wind energy, for example, is most efficiently produced in the central plains, whereas solar energy is most abundant in the West and Southeast.[23] Additional high-voltage transmission capacity is required to transport electricity produced from these regions to population centers.[24] Numerous studies have found that aggressive investment in high-voltage interregional lines is one of the most cost-effective ways of reducing carbon emissions.[25] For example, proposed increased interregional connections in the Eastern Interconnection[26] are estimated to result in at least $12 billion in net benefits.[27] Estimates for the Midcontinent Independent System Operator ("MISO") and Southwest Power Pool ("SPP") regions—RTOs in the Midwest and central southern parts of the United States—show that transmission development would lower energy costs by increasing the ability of low-cost wind to compete with fossil resources.[28]

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22. *See generally* Austin Brown et al., *Estimating Renewable Energy Economic Potential in the United States: Methodology and Initial Results*, Nat'l Renewable Energy Lab'y (2016), https://perma.cc/D6SA-9GLA; *see also* Christopher T. M. Clack, *The role of transmission in deep decarbonization*, Vibrant Clean Energy, LLC (Mar. 29, 2021), https://perma.cc/2XPH-3LVU. Alexandra B. Klass & Elizabeth J. Wilson, *Interstate Transmission Challenges for Renewable Energy: A Federalism Mismatch*, 65 Vand. L. Rev. 1801, 1811 (2019) (describing the need for "new transmission lines that connect areas of commercially viable wind resource to the grid."); *see also* Davis, *supra* note 19, at 164.
23. *See generally* Austin Brown et al., *Estimating Renewable Energy Economic Potential in the United States: Methodology and Initial Results*, Nat'l Renewable Energy Lab'y (2016), https://perma.cc/D6SA-9GLA; *see also* Clark, *supra* note 22.
24. Alexandra B. Klass & Elizabeth J. Wilson, *Interstate Transmission Challenges for Renewable Energy: A Federalism Mismatch*, 65 Vand. L. Rev. 1801, 1811 (2019) (describing the need for "new transmission lines that connect areas of commercially viable wind resource to the grid."); *see also* Davis, *supra* note 19, at 164.
25. *See* Alexander E. MacDonald et al., *Future cost-competitive electricity systems and their impact on US CO2 emissions*, 6 Nature Climate Change 526, 529 (2016); James McCalley & Qian Zhang, *Macro Grids in the Mainstream: An International Survey of Plans and Progress*, Americans for a Clean Energy Grid 16 (2020), https://perma.cc/J2QL-WYUE (finding that "interregional transmission facilitates cost reduction via sharing enabled by resource diversity, geographical diversity, and time diversity [and thereby lead] to significant decrease in the cost per unit of emissions reduction."); Aaron Bloom et al., *The Value of Increased HVDC Capacity Between Eastern and Western U.S. Grids: The Interconnections Seam Study*, 37 IEEE Trans. on Power Syss. 1760, 1764 (2022).
26. Covering, among others, ISO-NE, PJM, and NY-ISO. *U.S. electric system is made up of interconnections and balancing authorities*, U.S. Energy Admin. (Jul. 20, 2016), https://perma.cc/CM75-GNPZ.
27. Sheila Tandon Manz et al., *Economic, Reliability, and Resiliency Benefits of Interregional Transmission Capacity*, Gen. Elec. & NRDC (2021), https://perma.cc/2TT4-YDWC.
28. Catherine Hausman, *Power Flows: Transmission Lines, Allocative Efficiency, and Corporate Profits*, at 32–33 (NBER, Working Paper 32091, 2024) (describing how "fossil incumbents have been partly protected [from renewable competition] by transmission congestion").

Additional transmission capacity would also alleviate grid congestion.[29] Between 2016 and 2022, congestion costs increased nearly 220%, from $6.5 billion to $20.8 billion a year.[30] Because additional transmission allows low-cost resources to sell electric power across greater geographic areas—it effectively expands the market for generation—it allows low-cost suppliers to compete across a wider geographic footprint. Transmission can therefore mitigate market power issues that allow firms to increase the price of energy and justify investing in additional generation assets that would not be necessary if the grid operator could import power from neighboring regions.[31]

Transmission, especially lines that increase regional and interregional transfer capacity, also supports grid reliability by allowing resource-constrained zones to import power from their neighbors. For example, during Winter Storm Uri, Oklahoma and Texas faced similar weather conditions,[32] but Oklahoma faced less severe outages in part because it was able to draw on imported power from neighboring regions.[33] By contrast, Texas' inability to import power from its neighbors contributed to the catastrophic blackouts it experienced in

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29. Dev Millstein et al., *Empirical Estimates of Transmission Value using Locational Marginal Prices*, Berkeley Lab 1, 15–19 (Aug. 2022), https://perma.cc/Q842-LZKD. Ratepayers often bear congestion costs. *See* Richard Doying, Michael Goggin & Abby Sherman, *Transmission Congestion Costs Rise Again in U.S. RTOs* 1, Grid Strategies LLC (July 2023).
30. Millstein et al., *supra* note 29, at 2–3. Not every region has been affected equally. ISO New England, for example, experienced lower congestion costs than other RTOs between 2016 and 2022 (10-20% of the average congestion level in other RTO markets). The ISO points to its relatively aggressive investment in transmission over that period of time—it invested at more than double the rate of the RTO average in 2022. *2022 Assessment of the ISO New England Electricity Markets*, Potomac Econ. vi (Jun. 2023), https://perma.cc/Z8C8-WE8U. In most regions, however, customers face inflated rates because of congestion charges: even though the cost of producing electric energy has declined in the past decade, utility spending on delivery increased every year between 2010-2020. U.S. Energy Info. Admin., *Major U.S. utilities spending more on electricity delivery, less on power production* (Nov. 23, 2021), https://perma.cc/NR2Z-443X (noting that costs of power production have trended generally downwards over time, but have not lowered every year).
31. Millstein et al., *supra* note 29, at 15–19.
32. Srijana Shrestha et al., *The February 2021 U.S. Southwest Power Crisis*, 217 Elec. Power Systems Res. e109124, 1 ("Although the winter storm Uri 2021 affected Oklahoma and Texas with extreme cold weather conditions, consumers in Texas experienced a more severe impact on their electricity and natural gas infrastructures than the Oklahoma power infrastructure.").
33. Oklahoma is a member of Southwest Power Pool ("SPP"), which is interconnected with both ERCOT and MISO. In contrast, Texas' energy falls under ERCOT, which has a very limited interconnection with SPP only. *See id.* at 20 ("SPP has far more extensive tie-line capacity with the MISO than with ERCOT . . ."). *See generally* Joshua W. Busby et al., *Cascading risks: Understanding the 2021 Winter Blackout in Texas*, 77 Energy Rsch. & Soc. Sci. e102106 (2021).

February 2021.[34] The North American Electric Reliability Corporation recently released an Interregional Transfer Capability Study, which found that a lack of interregional transfer capacity could be expected to lead to reliability challenges and therefore "recommends 35 GW of additional transfer capability to demonstrably strengthen reliability."[35]

Finally, investing in transmission infrastructure can enhance the resilience of the electrical grid, making it less susceptible to outages caused by outdated infrastructure. Transmission infrastructure typically has an expected lifespan of fifty to eighty years.[36] In 2015, over 70% of transmission lines had been in service for at least twenty-five years, and transformers that managed approximately 90% of U.S. electricity flow had an average age of 40 years.[37] According to the Department of Energy, this aging infrastructure contributed to a thirteen-fold increase in "major electric disturbances" between 2000 and 2020.[38]

II. State and Federal Regulation of Transmission

For decades, state and federal policies have understood that a fragmented transmission planning process is both inefficient and can lead to market power abuses. For starters, when utilities make ad hoc investments in response to one-off needs (i.e. reliability, congestion, decarbonization goals), they reduce the justification for regional and interregional solutions that could have more cost-effectively addressed the region's transmission needs. A separate problem is that transmission owners often have an incentive to avoid coordinated transmission

34. *Shrestha et al.*, *supra* note 32, at 11 (showing outages and instability in ERCOT versus in SPP). For a discussion of other causes of the Texas blackouts, *see* Jacob Mays, Blake Shaffer & Han Shu, *Private Risk and Social Resilience in Liberalized Electricity Markets*, 6 Joule 369 (2022).

35. North Am. Electr. Rel. Corp., Interregional Transfer Capability Study as Directed in the Fiscal Responsibility Act of 2023 at 17 (Nov. 19, 2024); *id.* at 7, https://perma.cc/6WQC-DN8A ("[W]hen examining the ten-year forward-looking case that accounts for the future resource mix and forecasted load, energy inadequacy was identified across almost half of the studied transmission planning regions. This confirms congressional and electric industry concern that, given the changing resource mix, extreme weather, and anticipated demand, transmission infrastructure may place a strain on energy adequacy in the future. As a result, based on calculated deficiencies and the broader six-step approach to identify prudent additions to demonstrably strengthen reliability, the ITCS recommends 35 GW of additional transfer capability across different areas of the U.S.").

36. *What does it take to modernize the U.S. electric grid?*, Dep't of Energy (Oct. 19, 2023), https://perma.cc/WM2X-P8XR.

37. *See* Dep't of Energy, Quadrennial Technology Review 59 (2015), https://perma.cc/2FHJ-PMJ4; *Electric Grid Supply Chain Review,* Dep't of Energy viii (Feb. 24, 2022), https://perma.cc/6B26-EYLU (finding that about "over 90 percent of the nation's consumed power passes through an LPT" and "[t]he average age of installed LPTs in the Unites States is ~40 years").

38. *Electric Disturbance Events (OE-417) Annual Summaries*, Dep't of Energy, https://perma.cc/6LUL-UH47 (listing outage events by year).

planning processes that could expose their generation and transmission assets to competition or make it more difficult for them to justify future investments. Finally, all else equal, transmission owners prefer investments that minimize regulatory scrutiny and do not require that they compete with other developers. To address these challenges, federal regulators have encouraged utilities to provide nondiscriminatory, open access to their transmission systems and to interconnect with transmission providers in neighboring regions. Unfortunately, utilities have taken advantage of exemptions to these regional planning requirements and state siting laws to invest primarily in local projects.

A. Federal Transmission Policy

For most of the twentieth century, vertically integrated utilities owned and operated generation, transmission, and distribution assets.[39] They planned transmission in their own service territories, and regulators reviewed proposed investments to make sure that transmission owners were responding to customer needs.[40] Ratepayers were then charged a single rate that covered the utility's transmission and generation costs.[41] Since ratepayers were captive customers—they could only purchase electric energy from the incumbent utility in their service territory—they relied on regulatory supervision to make sure utilities made prudent investment decisions. Predictably, vertically integrated utilities that controlled both transmission and generation facilities often offered rivals unfavorable terms to connect to the transmission system or denied them transmission service altogether.[42]

FERC's efforts address these challenges began in 1993, when the Commission encouraged utilities to join Regional Transmission Groups (RTGs) that would coordinate to plan transmission investments.[43] Three years later, FERC issued Order No. 888, which required public utilities to provide

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39. Paul L. Joskow, *Transmission Policy in the United States*, 13 Utils. Pol'y 95, 98–99 (2005).
40. *Id.* at 100–01.
41. *See* Joshua Macey, *Zombie Energy Laws*, 73 Vanderbilt L. Rev. 1077, 1080–81 (2020) (describing the "filed rate doctrine" faced by vertically integrated utilities).
42. Nicolas Adrian McTyre, *FERC's Order No. 1000 From a Historical Perspective: Restructuring and Reorganization of Electric Transmission Markets From 1996 Until Present*, 6 George Washington J. Energy & Env't L. 51, 51–52 (2015).
43. . Policy Statement Regarding Regional Transmission Groups, 58 Fed. Reg. 41626, 41629 (July 30, 1993) (codified at 18 C.F.R. pt. 2) ("Properly functioning RTGs will enable[e] the market for electric power to operate in a more competitive, and thus more efficient manner, and provid[e] coordinated regional planning of the transmission system to assure that system capabilities are adequate to meet system demands"). This effort built on previous congressional and regulatory reforms meant to promote transmission planning. *See* Public Utility Regulatory Policies Act of 1978 ("PURPA"), Pub. L. No. 95–617, 92 Stat. 3117, 3135–36 (1978) (allowing FERC to require interconnection services in some instances); Energy Policy Act of 1992 ("EPAct"), Pub. L. No. 102–486, 106 Stat. 2776, 2916 (1992) (requiring utilities to provide wholesale transmission services if so ordered under FPA § 211).

non-discriminatory transmission service.[44] In the fifteen years following Order No. 888, FERC enacted a series of reforms meant to promote competitive wholesale power markets built atop open access transmission service. First, in 1999, FERC issued Order No. 2000, which encouraged utilities to join Regional Transmission Organizations ("RTOs"). One of FERC's goals in Order No. 2000 was to eliminate "any residual discrimination in transmission services that can occur when the operation of the transmission system remains in the control of a vertically integrated utility."[45] A few years later, FERC issued Order No. 2003, which required transmission providers to file standard generator interconnection procedures to "prevent undue discrimination, preserve reliability, increase energy supply, and lower wholesale prices for customers by increasing the number and variety of new generation that will compete in the wholesale electricity market."[46]

In 2007, FERC turned its attention to transmission planning and cost allocation. The Commission was worried that transmission owners' control of transmission planning was leading to inefficient transmission investment and could lead to discrimination in the wholesale market. To address those concerns, the Commission issued Order No. 890, which required open and transparent transmission planning.[47] But because Order No. 890 had not eliminated opportunities for discrimination in transmission planning, FERC in 2011 issued Order No. 1000, which required that all utilities participate in regional transmission planning processes. As a result of Order No. 1000, a transmission planning entity, which can be an RTO or a separate organization (often known as a regional transmission planning entity), must develop regional transmission plans and solicit competitive bids for regionally planned projects.[48]

Although FERC promulgated Order No. 1000 to address "remaining deficiencies in transmission planning and cost allocation processes,"[49] the Order does not appear to have accomplished its goals. While the next decade

44. Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities, 61 Fed. Reg. 21540 (Apr. 24, 1996) (codified at 18 C.F.R. pts. 35, 385).
45. Regional Transmission Organizations, 65 Fed. Reg. 810, 811 (Dec. 20, 1999) (codified at 18 C.F.R. pt. 35). At the time, FERC stressed that RTOs should remain independent from any market participants. *Id.* at 842.
46. Standardization of Generator Interconnection Agreements and Procedures, 68 Fed. Reg. 49846, 49847 (July 24, 2003) (codified at 18 C.F.R pt. 35).
47. Preventing Undue Discrimination and Preference in Transmission Service, 72 Fed. Reg. 12266 (Feb. 16, 2007) (codified at 18 C.F.R. pts. 35, 37) (explaining that open, transparent transmission planning was needed to make sure "transmission services [were] provided on a basis that [was] just, reasonable and not unduly discriminatory or preferential").
48. Importantly, Order No. 1000 also removes any federal rights of first refusal for regional transmission facilities. Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities, 77 Fed. Reg. 64980 (Oct. 24, 2012) (codified at 18 C.F.R. pt. 35). *See infra* Section II.A.3 (explaining rights of first refusal).
49. 76 Fed. Reg. 155, 49849.

saw a rapid increase in transmission spending, only a fraction of that spending went towards regionally planned, competitively solicited projects.[50] Concerned once again about the lack of regional planning, FERC in May 2024 issued Order No. 1920, which requires forward-looking, long-term transmission planning that considers at least seven types of benefits of new lines and requires that the costs of new lines be allocated in accordance with the benefits they create.[51] While Order No. 1920 is slightly more prescriptive than Order No. 1000, it essentially requires utilities to realize Order No. 1000's vision of regional planning in which transmission planners consider different benefits of transmission to ensure that they are cost-effectively meeting their regions' transmission needs.

A core assumption underlying the modern electricity sector is that member-run regional organizations should control all sorts of electricity functions, including resource adequacy markets, real-time and day-ahead markets, and regional and interregional transmission planning.[52] Although different grid entities are subject to slightly different requirements—for example, RTOs typically both oversee wholesale markets and conduct transmission planning whereas non-RTO regional transmission planning entities only conduct transmission planning and do not manage energy or resource adequacy markets—FERC has repeatedly encouraged utilities to place core governance functions under the control of non-profit member-owned organizations. In the context of transmission, these regional organizations are supposed to meet five requirements: independence, stakeholder input, competitive bidding, regional planning, and regional cost allocation.

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50. Johannes Pfeifenberger, *21st Century Transmission Planning: Benefits Quantification and Cost Allocation*, Brattle (Jan. 2022), https://perma.cc/35WL-SJYR (finding that "More than 90% of [transmission investment is] justified solely based on reliability needs without benefit-cost analysis" and that "About 50% [of investment is] solely based on 'local' utility criteria (without going through regional planning processes)"); *see also* FERC, *Order No. 1920*, 89 Fed. Reg. 113, 49304 (finding that "the majority of investment in transmission facilities since the issuance of Order No. 1000 has been in local transmission facilities").

51. 89 Fed. Reg. 113, 49389-90 (defining the seven benefits transmission providers are required to consider), 49475-76 (detailing the proposed cost allocation mechanisms). Order No. 1920 also requires that transmission planners consider certain grid enhancing technologies and that utilities "right-size" local projects by considering whether it would be more cost effective to address those needs in the regional process.

52. 77 Fed. Reg. 206, 64981 (requiring that "each public utility transmission provider . . . participate in a regional transmission planning process that produces a regional transmission plan [and coordinate] between neighboring transmission planning regions for new interregional transmission facilities); *see also* Joseph H. Eto & Guilia Gallo, *Regional Transmission Planning: A review of practices following FERC Order Nos. 890 and 1000*, Lawrence Berkeley Nat'l Laboratory v-vi (Nov. 2017), https://perma.cc/3Y4A-9PX4; Ann P. Cohn, "The Promise of Regional Coordination and Power Planning," 8 Nat. Res. & Env't. 23, 23 (1994) (describing FERC's intent behind RTGs, the precursor of RTOs).

1. Independence

FERC has consistently required RTOs and non-RTO transmission planning entities to possess governance features that ensure that they are independent of industry participants. For example, in Order No. 2000, FERC required that "the RTO, its employees, and any non-stakeholder directors must not have any financial interests in any market participants . . . [,] a decision-making process that is independent of control by any market participant or class of participants . . . [, and] exclusive and independent authority to file changes to its transmission tariff with the Commission under section 205 of the FPA."[53] Order No. 890 sought to further reduce members' control over transmission planning by requiring that non-stakeholder parties be able to participate in transmission planning.[54] And Order No. 1000 emphasized the importance of transparency and stakeholder engagement, requiring RTOs and non-RTO transmission planning entities to publish information in accessible ways and consult with stakeholders while developing their regional plans.[55] In Order No. 1000, FERC also specifically stressed that transmission planners must "have a degree of independence from market participants." FERC was responding to comments that had expressed concern that independence was needed to "promote equitable and economically supportable results in terms of which transmission facilities are built and who ultimately pays for them."[56] And Order No. 1920 goes further still, requiring transmission planners to consult with states about transmission planning and cost allocation and, if states agree to a cost allocation approach, even requiring that transmission providers either propose that cost allocation method or submit two proposals to FERC—both the transmission providers' preferred method and the approach suggested by the states.[57]

2. Stakeholder Input

FERC has also sought to make sure that transmission planning incorporates the views of affected parties. To that end, all regional projects built in RTO and non-RTO transmission planning regions must be included in the planning entity's regional transmission plan. That plan is the result of a multi-year process in which stakeholders are given opportunities to provide input. FERC has stressed that stakeholders must be able to participate in decisionmaking

53. FERC Order No. 2000, 89 FERC ¶ 61,285, 153 18 CFR § 35 (Dec. 20, 1999).
54. 72 Fed. Reg. 60, 12319 (stating that the Commission expects "non-public utility transmission providers to participate in the proposed planning processes, given that effective regional planning cannot occur without the participation of all transmission providers, owners, and customers").
55. 76 Fed. Reg. 155, 49863.
56. *Id.* at 49866.
57. *See Building for the Future Through Electric Regional Transmission Planning and Cost Allocation*, FERC, Order No. 1920-A, P. 13 (Nov. 21, 2024) [hereinafter Order No. 1920-A].

processes in specific and predetermined ways.[58] Importantly, when FERC reviewed Order No. 1000 compliance filings, it insisted that transmission planners provide stakeholders with "the ability to participate in the identification of regional transmission needs and corresponding solutions."[59] Order No. 1920-A, by instructing transmission providers to submit cost allocation methods proposed by states, creates additional mechanisms by which interested parties can influence transmission investment.[60] Requirements such as these aim to ensure that transmission planning incorporates the views and interests of all interested parties—including consumers, generation owners, and state officials—rather than simply the interests of transmission owners and other parties responsible for developing the transmission plan.

3. *Competitive Bidding*

Transmission planners must generally use competitive solicitations for regionally planned lines. Among other things, Order No. 1000 eliminated utilities' federal right of first refusal for projects selected for regional cost allocation.[61] The right of first refusal gave incumbents a first pass at building any developments in their area of service. Now, regional projects (save for upgrades to existing facilities and certain "immediate-needs" reliability investments)[62] must go through a competitive bid solicitation process meant to give nonincumbent transmission developers an equal opportunity to bid on, propose, and construct transmission projects.[63] FERC felt this was "necessary and appropriate to ensure that rates for jurisdictional services are just and reasonable,"[64] since rights of first refusal could "have the effect of limiting the identification and evaluation of potential solutions to regional transmission needs and, as a result, increasing the cost of transmission development that is recovered from jurisdictional customers through rates."[65]

4. *Regional Planning*

Transmission owners must also engage in open, transparent, forward-looking, multi-benefit planning. FERC first formalized regional transmission

58. *Id.* at 49867.
59. *Id.* at 49848.
60. *See* Order 1920-A, supra note 57, at 13.
61. 76 Fed. Reg. 155, 49842, 49886.
62. Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection, 87 Fed. Reg. 26504, 26562–63 (May 4, 2022).
63. 76 Fed. Reg. 155 at 49886; *see also* Joseph H. Eto & Guilia Gallo, *Regional Transmission Planning: A review of practices following FERC Order Nos. 890 and 1000*," *supra* note 52, at 5–6 (explaining how competitive bidding and sponsorship works in RTO and non-RTO regions).
64. 76 Fed. Reg. 155 at 49886.
65. *Id.* at 49891.

planning in Order No. 890, when it ordered "each public utility transmission provider . . . to submit . . . a proposal for a coordinated and regional planning process."[66] Order No. 890 explicitly connected incumbent-run transmission planning to market power concerns, explaining that it could not "rely on the self-interest of transmission providers to expand the grid in a nondiscriminatory manner."[67] As FERC explained,

> Although many transmission providers have an incentive to expand the grid to meet their state-imposed obligations to serve, they can have a disincentive to remedy transmission congestion when doing so reduces the value of their generation or otherwise stimulates new entry or greater competition in their area. For example, a transmission provider does not have an incentive to relieve local congestion that restricts the output of a competing merchant generator if doing so will make the transmission provider's own generation less competitive. A transmission provider also does not have an incentive to increase the import or export capacity of its transmission system if doing so would allow cheaper power to displace its higher cost generation or otherwise make new entry more profitable by facilitating exports.[68]

A few years later, in 2011, FERC became concerned that open and transparent planning processes had not sufficiently addressed all the challenges with transmission planning, and so it required regional transmission planners to engage in regional and interregional planning that prospectively identified the most cost-effective ways of meeting their transmission needs. Order No. 1920 builds on this requirement by directing transmission planners to engage in forward-looking, multi-benefit planning that considers seven types of benefits of new transmission.[69]

5. *Regional Cost Allocation*

Both FERC and the federal courts have also understood the FPA to require that the costs of new transmission investment be allocated to the beneficiaries of the project. In Order No. 1000, for example, FERC required utilities to standardize methods for allocating the costs of new transmission facilities selected in

66. Order No. 890, *Preventing Undue Discrimination and Preference in Transmission Service*, 118 FERC ¶ 61,119 at 437 (2007) (to be codified at 18 C.F.R. pts. 35, 37) [hereinafter Order No. 890].

67. *Id.* at 422; *see also id.* at 39 ("[I]t is in the economic self-interest of transmission monopolists, particularly those with high-cost generation assets, to deny transmission or to offer transmission on a basis that is inferior to that which they provide to themselves."); *see also id.* at 57 ("[V]ertically-integrated utilities do not have an incentive to expand the grid to accommodate new entries or to facilitate the dispatch of more efficient competitors.").

68. *Id.* at 422.

69. 89 Fed. Reg. 113, 49399–413.

their regional transmission plan.[70] Previously, "cost allocation issues [were] often contentious and prone to litigation because it is difficult to reach an allocation of costs that is perceived as fair, particularly for RTOs and ISOs that encompass several states."[71] There was a risk of free riders for projects that affected multiple utilities' transmission systems. To combat this, the Commission proposed six regional cost allocation principles.[72] Together, FERC hoped these six principles would make cost allocation a less contentious and more consensus-driven process. [73]

Order No. 1920 builds on Order No. 1000's planning and cost allocation requirements.[74] Transmission planners can work with states to develop a voluntary method for allocating the costs of transmission. However, Order No. 1920 requires that, if states do not reach an agreement, the costs must be allocated to the beneficiaries of new transmission lines and transmission upgrades. Order No. 1920-A slightly modified Order No. 1920's approach to cost allocation by mandating that, if states agree to an alternative method for allocating costs, then the transmission provider must also submit that proposal to FERC.[75] As one of us has written elsewhere, courts, too, have long understood the FPA's prohibition on undue discrimination to require a beneficiary-pays approach to cost allocation.[76]

B. Siting

New transmission lines must also navigate complex siting and permitting requirements. Today, state and local regulators typically have primary authority over transmission siting. FERC can step in only to exercise its backstop siting authority, which is triggered when a line is built on a designated National Interest Electric Transmission Corridor and when a state has either refused to permit the line or not acted within a year.[77] Siting refers to two different processes:

70. *Id.* at 49918 (citing to 76 Fed. Reg. 155).
71. *Id.* at 49919 (citing to 76 Fed. Reg. 155).
72. The six principles are (1) costs must be allocated in a way roughly commensurate to benefits; (2) parties that receive no benefits must not be involuntarily allocated costs; (3) if a benefit-to-cost ratio threshold is used to determine which facilities are sufficiently beneficial to be included in a regional transmission plan, that ratio is not to exceed 1.25; (4) allocation method for costs of a regional facility must allocate costs solely within that region unless another region voluntarily assumes costs; (5) cost allocation methods must be transparent and adequately documented; and (6) transmission planning regions may use different cost allocation methods for different types of transmission facilities. *Id.* at 49932–33.
73. *See infra* Section II.A (describing the initial formation process of RTOs).
74. FERC, *Order No. 1920*, 89 Fed. Reg. 113, 49475–81.
75. FERC, *Order No. 1920-A,* https://perma.cc/KT5J-L77C.
76. *See* Joshua Macey & Jacob Mays, *The Law and Economics of Transmission Planning and Cost Allocation*, 45 Energy L. J. 209, 239–48 (2024) (describing appeals to FERC cost allocation decisions).
77. *See infra* Section IV.C.4 (describing FERC's backstop siting authority).

first, it refers to the process of receiving a certificate of public convenience and necessity ("CPCN")[78] from the states through which the line crosses; and second, it refers to the specific location of the line (the actual "siting"). High-voltage interstate transmission lines currently take between eight to ten years to complete. Approximately four of those years involves navigating the state approval process.[79]

III. Outsourcing Transmission Planning

To build transmission, utilities need to plan new projects, receive permits to build those projects, and find a source of funding that will allow them to pay for new lines. Under current law, states have primary authority over permitting, and the federal government—typically, though not always, FERC—is responsible for regional planning and cost allocation.[80]

Although transmission is supposed to be planned regionally and be selected through competitive solicitations, today most planning is conducted locally without considering whether regional or interregional lines could more cost-effectively address transmission needs and with little, if any, regulatory scrutiny.[81] Order No. 1920 is a significant improvement over the status quo,

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78. Required for most lines.

79. Liza Reed, *Transmission Stalled: Siting Challenges for Interregional Transmission*, Niskanen Center 4 (2021), https://perma.cc/E7ZF-LVAV. Mention that there are other challenges here not about states. NEPA, BLM, etc. Timelines for receiving a certificate of public necessity and convenience vary by state, as do the specific requirements developers need to receive a permit to begin construction. If a state acts mostly as a "pass-through" for the prospective transmission line, rather than as an end destination, it can be difficult to convince the state that the benefit of the new line outweighs its costs. *Id.* at 4–5. *See* Alexandra B. Klass & Elizabeth J. Wilson, *Interstate Transmission Challenges for Renewable Energy: A Federalism Mismatch*, 65 Vand. L. Rev. 1801, 1804 (2019). A line may provide a net benefit to consumers across the U.S., but be denied a permit because of citizen opposition, politics, or cost concerns from one specific state. As a result, it is generally easier for developers to build local transmission lines—which require the consent of just one state, which is certain to benefit from the line—than it is to build regional or interregional lines, which bring along a larger administrative burden.

80. *See* Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities, 76 Fed. Reg. 49842, 49854–58, 49932–36 (Aug. 11, 2011) (codified at 18 C.F.R. pt. 35) (detailing regional planning and cost allocation rules).

81. *See* Joseph H. Eto, *Planning Electric Transmission Lines: A Review of Recent Regional Transmission Plans* 33, Lawrence Berkeley Nat'l Lab'y (Sep. 2016), https://perma.cc/PAK4-9Z8P ("Among the plans that were available for review, many did not identify new projects that would qualify for regional cost allocation and require an open competitive process to select a project developer . . . Only CAISO, PJM, and SPP have conducted open solicitations for transmission developers to propose projects that would qualify for regional cost allocation."); Johannes Pfeifenberger, Transmission Planning and Benefit-Cost Analyses 37 (Brattle 2021), https://perma.cc/WDW6-26QC; Julie Lieberman, *How Transmission Planning & Cost Allocation Processes Are Inhibiting Wind & Solar Development in SPP, MISO,*

requiring long-term, multi-benefit planning and beneficiary-pays cost allocation.[82] That said, it does not fully eliminate the core problem with transmission planning and cost allocation, which is that the existence of carveouts to regional planning requirements give incumbent transmission owners both the incentive and ability to overinvest in small local projects.

A. Local Planning

The majority of transmission projects that have been built since Order No. 1000 went into effect have been planned by individual utilities and have not had to undergo competitive solicitations. Broadly speaking, transmission lines can be selected in one of two ways. First, they can go through forward-looking, multi-benefit planning in which the planner identifies transmission needs, conducts competitive solicitations to determine who will build the line, and allocates the costs to the customers who benefit from the line. That is the process envisioned by both Order Nos. 1000 and 1920, and it currently accounts for a very small percentage of transmission spending.[83] Second, some projects can be planned by individual utilities outside the regional multi-benefit planning process and without competitive procurements.

Confusingly, some of the projects in this second category are rolled into the regional plan even though the incumbent utility has a right to build the lines, is not required to allocate costs to the line's beneficiaries, and is not required to compete with other developers. For example, in SPP, PJM, MISO, and ISO-NE, projects that address certain reliability issues are excluded from competitive bidding.[84] Often utilities themselves develop the criteria for these projects. When we refer to local projects, we are referring to the second category. Thus, even if a project is technically included in the regional plan, we do not count it as a regional project if it was not selected in a multi-benefit planning process or was not selected through a competitive solicitation.

& PJM, Concentric Energy Advisors xi, 7, 17 (Mar. 2021), https://perma.cc/Q8B9-2Q3M (finding that "[t]ransmission owners and most RTOs have focused almost exclusively on local or reliability projects with short time frames" and that "[t]o date, interregional transmission expansion has been virtually non-existent").

82. *See* 89 Fed. Reg. 113, 49312 (discussing the requirement to participate in long-term regional transmission planning), 49389–90 (defining the seven benefits transmission providers are required to consider), 49475–76 (detailing the proposed cost allocation mechanisms).

83. *See RTEP: Planning for Long-Term Transmission Needs*, PJM (Jan. 3, 2024), https://perma.cc/C6PT-M949 (describing PJM's regional transmission expansion plan); *see also* PJM, *Operating Agreement – Schedule 6*, FERC Docket No. ER22-1420-000 (2023).

84. Johannes P. Pfeifenberger et al., Brattle, Cost Savings Offered by Competition in Electric Transmission 20 (2019) (describing reliability exclusions to the competitive bidding process in ISO-NE, MISO, PJM, and SPP).

Overinvestment in non-regionally planned projects is occurring in both restructured and vertically integrated markets. In MISO, for example, between 2018 and 2020, more than 70% of investment went towards local needs, with the remainder going to non-competitively procured reliability projects.[85] In PJM, about two-thirds of total transmission investment was made outside the regional planning process.[86] As of 2022, no project had been selected for regional cost allocation in the non-RTO/ISO regions since Order No. 1000 went into effect.[87] Altogether, about half of the annual transmission investment in the United States goes to local projects that are planned by individual utilities to meet the needs of the their customers.[88] As FERC has explained, "the status quo appears to be resulting in a disproportionate share of transmission facilities . . . being developed outside regional transmission planning and cost allocation processes, resulting in less efficient and cost-effective transmission development."[89] State public utility commissions across the country have sounded the alarm over the lack of oversight utilities face when building "local" projects, and the ease with which they are able to pass on costs to consumers without any meaningful review.[90]

85. Johannes Pfeifenberger et al., Brattle Group & Grid Strategies LLC, Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs 2 (Oct. 2021) (detailing MISO transmission spending).

86. FERC, *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, 179 FERC ¶ 61,028 ¶ 40 (Apr. 21, 2022) (finding that "transmission investment to resolve local needs accounted for almost 80% of total transmission investment in MISO from 2018 to 2020. Similarly, in PJM, about two-thirds of the total transmission investment in the region went to resolving local needs").

87. 179 FERC ¶ 61,028 ¶ 35 (Apr. 21, 2022) (citing LS Power Oct. 12 Comments, app. I, at 18 & n.57; FERC, Staff Report, *2017 Transmission Metrics*, at 19 (Oct. 6, 2017), https://perma.cc/ZFL9-GB5L); Alexandra B. Klass, Joshua C. Macey, Shelley Welton, & Hannah Wiseman, *Grid Reliability Through Clean Energy*, 74 stan. l. rev. 969, 1029 (2022). Note that MISO expects the first and second tranche of its LRTP projects to qualify for sub-regional cost allocation. *See* MISO, *LRTP Tranche 2 – Cost Allocation*, https://perma.cc/AY8H-VYKR (Mar. 4, 2024) ("As with Tranche 1, MISO anticipates the Tranche 2 portfolio will deliver sufficient benefits to qualify under the current Multi-Value Project (MVP) cost allocation mechanism, with costs allocated only to the subregion where benefits are spread.").

88. Johannes Pfeifenberger & Joseph DeLosa, Brattle, Transmission Planning for a Changing Generation Mix 1 (Oct. 18, 2022), https://perma.cc/6UR8-P656 ("About 50% [of annual transmission investment is] solely based on "local" utility criteria (without going through regional planning processes)").

89. 179 FERC ¶ 61,028 ¶ 36 (Apr. 21, 2022). In fact, investment in regional facilities has *declined* in some regions compared to before the implementation of Order No. 1000. *Id.* ¶ 39.

90. *See, e.g.*, The Office of the People's Counsel for the District of Columbia & Maryland Office of People's Counsel, Comments Regarding the Notice of Proposed Rulemaking (Aug. 17, 2022), https://perma.cc/NGZ7-R63E (stating that "the current piecemeal planning process is locally driven, inefficient, lacking in transparency and opportunities for stakeholder engagement, and largely ignores, rather than utilizes, the potential benefits of competition").

B. Misaligned Investment Incentives

Utilities have strong incentives to prefer local projects. They earn a healthy return on these projects while also protecting their generators from competition from resources in neighboring regions and avoiding regulatory scrutiny that might have revealed opportunities for cost savings or lower-cost projects.

1. Rate Basing Local Projects

One reason utilities want to avoid the regional planning process is that they have a financial incentive to overinvest in capital projects.[91] Utilities earn a return on capital expenses. If a utility spends $100 on transmission and is entitled to a ten percent return, it will earn $10; if it spends $1000 on transmission, it will earn $100. Thus, if it would be less expensive to build a single regional or interregional project, a utility may prefer to spend more money on smaller projects in order to increase its capital costs—and in turn, its return on capital expenses.

Today, FERC uses something called formula rates to determine the rates utilities can charge for transmission service.[92] This is a traditional cost-of-service approach in which the Commission authorizes a return based, among other things, on the utility's financing costs and the costs of operating and maintaining the lines.[93] Absent a showing that an investment was not prudently incurred, a utility automatically recovers its costs and earns a return.[94] Given the scale of

91. *See* Ari Peskoe, *Is the Utility Transmission Syndicate Forever?*, 42 Energy L. J. 1, 35 (2021) ("[Utilities] are generally incentivized to disfavor new technologies . . . that might obviate the need for additional transmission infrastructure, in part because they are not as predictably profitable under the cost-of-service business model."); Harvey Averch & Leland L. Johnson, *Behavior of the Firm Under Regulatory Constraint*, 52 Am. Econ. Rev. 1052, 1059 (1962) (discussing the firm's incentive to "to acquire additional capital if the allowable rate of return exceeds the cost of capital" in the face of formula rates); Roger Sherman, *The Averch and Johnson Analysis of Public Utility Regulation Twenty Years Later*, 2 Rev. Indus. Org. 178, 188 (1985) (describing how it "should come as no surprise that rate-of-return regulated firms may literally waste capital"); Steve Cicala, *Restructuring the Rate Base* 2–3 (Oct. 19, 2022), https://www.stevecicala.com/papers/restructuring_rate_base/restructuring_rate_base_draft.pdf (finding that utilities in restructured markets spend more on transmission and distribution, which remain rate regulated).

92. *See* FERC, *Formula Rates in Electric Transmission Proceedings: Key Concepts and How To Participate*, https://perma.cc/D52Y-PBMC.

93. *See id.*

94. Commissioner Christie has been a vocal critic of both FERC's formula rate treatment and incentive-based regulation. *See, e.g.* 185 FERC ¶ 61,198, Potomac-Appalachian Transmission Highline (Dec. 19, 2023) (Comm'r Christie, concurring) (finding that since 2008, the total amount that consumers have been forced to pay to PATH's developers has been approximately $250 million – that's right, let me repeat: consumers have paid roughly $250 million for a project that was never built nor found needed by a single state regulator."); *id.*

transmission investment that is currently occurring in the United States, the fact that most of that investment goes towards local projects suggests that these incentives are sufficient to encourage utilities to invest in the transmission system. And the fact that formula rates authorize a return based on the utility's costs—not the expected benefits the project will produce—means utilities have little financial incentive to invest in more cost-effective projects or projects that yield large benefits.[95]

2. *Avoiding Competition*

Utilities also have an incentive to avoid being forced to compete with other transmission providers. Not only do utilities want to be guaranteed that they will receive the contract to build new transmission, but they also want to avoid competitive processes that might force them to submit lower-cost bids so that they receive the right to build new transmission. The $40 billion in annual spending on transmission in recent years, most of which has not undergone competitive solicitations, suggests that transmission development has become a healthy source of revenue for incumbent utilities. All else equal, a firm will prefer to rely on a planning process that does not force it to compete with other transmission developers. Ari Peskoe has documented this phenomenon in detail in his work on transmission investment.[96]

3. *Protecting Generator Market Power and Justifying the Need for More Generation*

When the parent company of a transmission owner also owns generation assets, it may have an incentive to avoid investing in large transmission facilities in order to avoid exposing its generating units to competition from low-cost power producers. From the perspective of vertically integrated utilities, it can

("By this point, you may be asking yourself whether there are any incentives the Commission did not give to the PATH developers."), https://perma.cc/4Z2B-MGJR.

95. FERC does have authority under Section 219 of the FPA to authorize incentive-based rate treatment to promote certain transmission investment. *See* Energy Policy Act of 2005, Pub. L. No. 109-58, § 1241, 119 Stat. 594 (2005) (codified at 16 U.S. Code § 824s). The Commission has provided guidance on when utilities can request additional incentives to make transmission investment. For example, there is a rebuttable presumption that a project qualifies for incentive-based rate treatment if it came out of the regional planning process. *See* Order No. 679, Promoting Transmission Investment through Pricing Reform, 141 FERC ¶ 61,129, P. 36–37 (2012) (2012 Incentives Policy Statement). Our view is that the ROE adder is too broad. For example, FERC provides an ROE adder to utilities simply for participating in an RTO. And FERC does not, however, require utilities to do a cost-benefit analysis when applying for the ROE adder. As a result, transmission incentives fail to distinguish between projects that genuinely yield significant benefits and those that simply meet certain formal criteria.

96. *See generally* Peskoe, supra note 91.

be risky to invest in regional and interregional projects that reduce congestion because doing so can cause their generators to earn less revenue in the energy market.[97] Moreover, if transmission investment would enable a region to meet its energy needs by drawing resources from outside a firm's service territory, a firm may be concerned that transmission will result in it being forced to retire its generation assets. Relatedly, when transmission congestion can be used to justify investing in additional generation, firms may prefer to avoid regional and interregional projects if they think it will be more profitable for them to build new generating units.

Recent work has shown that regional and interregional transmission investment poses a real risk to firms that own both generation and transmission. For example, one of us has described how Entergy, a utility in Louisiana and Arkansas, chose to invest in a gas-fired power plant that cost approximately $900 million even though it arguably provided many of the same benefits as a proposed $100 million transmission project.[98] Catie Hausman has estimated that additional transmission capacity connecting MISO-North and MISO-South could reduce energy market prices in Louisiana and Arkansas by nearly $1 billion annually,[99] and she has recently extended this work across the country.[100] Of course, we cannot prove that utilities are anticompetitively channeling investment to local projects because they want to protect their generation assets and justify future investments. Still, at the very least, it is in utilities' financial interest to increase energy market revenues and make sure that they do not strand the investments they have made in baseload power. Their reluctance to invest in regional and interregional projects could therefore be explained by the fact that small, local projects do not pose the same competitive threat to the investments they have made in generation facilities.

4. *Minimizing Regulatory Oversight*

Another reason transmission owners rationally prefer to invest in local projects is that doing so allows them to avoid or minimize regulatory scrutiny. Ideally, regional planning requirements—stakeholder review, independent cost-benefit analyses, competitive bidding, and so on—should remove significant control from incumbent utilities and reduce their ability to protect existent generators from new market entrants. But the reality is that many local projects receive little, if any, review from either state or federal regulators.

97. *See generally* Hausman, *supra* note 28. *See also* Kovvali & Macey, *supra* note 13.

98. *See* Joshua C. Macey, *Outsourcing Electricity Market Design*, 91 U. Chi. L. Rev. 1243, 1296–97 (2024).

99. Catherine Hausman, *Power Flows*, *supra* note 28, at 3.

100. *See* Dasom Ham, Owen Kay, & Catherine Hausman, Power Flows Part 2: Transmission Lowers Generation Costs, But Generator Incentives Are Not Aligned (Dec. 2024) (manuscript on file with authors).

Utilities appear to take advantage of exemptions to the regional planning process to protect their financial interests.[101] Consider, for example, the "immediate-needs" exception to the competitive bidding requirement.[102] The immediate-needs exemption is meant to allow utilities to quickly respond to genuine reliability issues. When utilities pushed for this exemption during Order No. 1000,[103] FERC was responding to concerns that some exemptions to regional planning should be tolerated to avoid delays that could undermine system reliability. The Commission established five criteria to determine whether a project should qualify for the immediate-needs exemption:

1. The project must be needed in three years or less to solve reliability criteria violations;
2. The regional transmission planner must separately identify and then post an explanation of the reliability violations and system conditions in advance for which there is a time-sensitive need, with sufficient detail of the need and time-sensitivity;
3. The regional transmission planner must provide to stakeholders and post on its website a full and supported written description explaining: (1) the decision to designate an incumbent transmission owner as the entity responsible for construction and ownership of the project, including an explanation of other transmission or non-transmission options that the region considered; and (2) the circumstances that generated the immediate reliability need and why that need was not identified earlier;
4. Stakeholders must be permitted time to provide comments in response to the project description, and such comments must be made publicly available; and

101. *See, e.g.*, Peskoe, *supra* note 91, at 54.

102. *See, e.g.*, *PJM*, 142 FERC ¶ 61,214 ¶ 222, 248 (Mar. 22, 2013) (discussing PJM's protest to the required removal of ROFR, addressing the immediate-needs exception); *ISO-NE*, 150 FERC ¶ 1 ¶ 235–36 (Mar. 19, 2015) (rejecting ISO-NE's request to maintain ROFR, allowing for immediate-needs exceptions); *SPP* FERC ¶ 144,059 ¶ 123 (Oct. 16, 2014) (rejecting SPP's attempt to maintain ROFR).

103. *See PJM*, 142 FERC ¶ 61,214 at ¶ 222, 248 (discussing PJM's protest to the required removal of ROFR, addressing the immediate-needs exception); *ISO-NE*, 150 FERC ¶ 1 at ¶ 235–36 (Mar. 19, 2015) (rejecting ISO-NE's request to maintain ROFR, allowing for immediate need-exceptions); *SPP* FERC ¶ 144,059 at ¶ 123 (Oct. 16, 2014) (rejecting SPP's attempt to maintain ROFR). Order No. 1920 takes modest steps to prevent utilities from abusing the immediate-needs exemption but does not fully address the issues the exemption creates. For example, Order No. 1920 requires that utilities consider right-sizing projects, which means they prospectively study whether anticipated local upgrades can be addressed in a regional plan. *See* 89 Fed. Reg. 113, 49533. But it is unclear how FERC will make sure utilities perform these studies diligently, how they will coordinate with regional planners to make sure right-sizing analysis considers other benefits or proposed lines, or how FERC will enforce this provision if utilities continue to overinvest in local projects.

5. The Responding RTO must maintain and post a list of prior year designations of all immediate-needs reliability projects for which the incumbent transmission owner was designated as the entity responsible for construction and ownership of the project. The list must include the project's need-by date and the date the incumbent transmission owner actually energized the project. The Responding RTO must also file the list with the Commission once a year.[104]

The extent to which the immediate-needs exemption offers a means of arbitraging around Order No. 1000's planning requirements turns primarily on the first criterion: projects must usually be needed in three years or less to maintain grid reliability, or else there would not be an immediate need.[105]

In practice, the immediate-needs exemption appears to contribute to suboptimal planning that forces ratepayers to pay for expensive upgrades and reduces the need for regionally planned lines that go through competitive solicitations. For example, PJM in late 2023 approved a package of "immediate-needs"[106] grid solutions that were needed to make sure that the retirement of the Brandon Shores coal-fired power plant did not undermine reliability in the PJM region.[107] These projects were justified because the recently announced retirement of the Brandon Shores power plant was expected to lead to an unacceptably low level of reliability in PJM. These immediate-needs projects were assigned mainly to incumbent affiliates of Exelon and did not go through a competitive bidding process.[108] Importantly, PJM became aware of the need to make these transmission investments only after Exelon studied the effect of retiring the Brandon Shores power plant. By the time Exelon completed the relevant studies, there was not enough time to consider alternatives or conduct a competitive solicitation. According to the Maryland Office of People's Counsel ("OPC"), PJM failed to consider any transmission or non-transmission alternatives, either proactively (as required by its governance documents) or after the fact.[109] Nor did PJM analyze the cost estimates proposed by Exelon, which the company increased by 10% "only several weeks [after] approval of the same projects."[110]

104. *In re PJM*, 142 FERC ¶ 61,214 ¶ 248.

105. *See id*. Criteria ii-v primarily serve to keep RTOs accountable to their stakeholders when using the exception.

106. *See infra* Section IV.C (describing the "immediate-needs" loophole to competitive bidding).

107. *In Re PJM Interconnection*, 185 FERC ¶ 61,107 ¶ 12–13 (Nov. 8, 2023).

108. *Protest of the Maryland Office of People's Counsel*, FERC Docket No. ER23-2612-000, ER23-2612-001, at 3–4 ("The PJM Board's approval assigned the responsibility for the construction of these projects to incumbent transmission owner ('TO') affiliates of Exelon, Corp., primarily Baltimore Gas and Electric Company ('BGE').").

109. *Id.* at 14–15.

110. *Id.* at 22.

It is of course possible—and perhaps likely, in this case—that Brandon Shores' retirement would undermine reliability, but it is nevertheless notable that it was in Exelon's financial interest to wait to analyze the reliability impacts of Brandon Shores' retirement, since doing so ensured that the reliability challenges could only be addressed through "immediate-needs" projects.[111] Thus, the failure to engage in forward-looking planning allowed the incumbent transmission owner to make hundreds of millions of dollars in investments—all while avoiding meaningful regulatory scrutiny.

And there is reason to think that not all immediate-needs projects are responding to reliability challenges that must be addressed within three years. Immediate-needs projects are frequently plagued by significant delays and rarely meet the three-year window that justifies exempting them from the competitive bidding process. In ISO-NE, for example, 30 projects were designated as immediate-needs projects between 2015 and 2019, but only six of those projects were actually in service within three years. The remaining twenty-four took significantly longer.[112] These results point to a related issue: utilities themselves often develop the criteria regional transmission planning entities use to determine whether a line should be exempted from regional planning requirements, and when lines are exempted from regional planning requirements, there is often little opportunity for regulators and other stakeholders to obtain information about why the line is needed or propose alternative solutions to the reliability need.[113]

This and similar exemptions to regional planning requirements appear to have become the primary means through which utilities plan new transmission investments. In October of 2019, FERC initiated investigations in PJM, ISO-NE, and SPP to determine whether the immediate-needs exemption was being overused and whether projects were receiving the designation without evidence that the

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111. The puzzling result reached by PJM is further complicated by its failure to publish publicly or respond to stakeholder comments, as required by its governing documents. *See id.* at 20 ("Neither submittal was posted and made publicly available to OPC's knowledge; nor were any answers to OPC's questions from PJM posted to the PJM website.").

112. *See* FERC, *Response of ISO New England Inc. to October 17, 2019 Order Instituting Section 206 Proceedings Under EL19-90 – Attachment C & D*, 1-4, Docket No. EL19-90-000 (Dec. 27, 2019) (showing a list of projects with their need-by date and projected in-service date); *see also* Philip Killeen, *Swallowing the Rule: Why FERC's "Immediate Need Exemption" Frustrates Competitive and Climate-Smart Electricity Sector Transmission Planning Under Order No. 1000*, 21 Sust. Dev. L. & Pol'y 9, 10 (2022).

113. *See, e.g.* Joint New England Transmission Owner Asset Condition Process Guide 3 (Oct. 23, 2024), https://perma.cc/M9Y8-R35Y ("Each Transmission Owner has programs designed to track and monitor the condition of its transmission assets, to determine solutions to asset condition issues as they are identified, and to implement asset condition projects in order to cost-effectively support the continued reliability of the New England transmission system."); *id.* ("While each Transmission Owner devises unique asset condition strategies best suited to the demographics of its transmission facilities and the specific needs of its customers, all Transmission Owners broadly follow similar general practices for identifying and implementing asset condition projects.").

projects were needed.[114] ISO-NE states have objected to New England utilities' increasing use of asset management and asset condition projects, which benefit from similar regulatory treatment.[115]

Under the current regulatory framework, it is difficult to prevent utilities from taking advantage of exemptions to regional planning requirements. Order No. 1000 did not include a mechanism to determine whether an update would be needed in the future, or even to verify whether projects do in fact serve a genuine need. Instead, RTOs are given significant discretion over what projects qualify for these exemptions, and it is only *ex post* that FERC or the RTOs' stakeholders can evaluate that decision.[116] Nor do utilities have a financial incentive to avoid overinvesting in local projects. When utilities build local projects, they receive something called FERC formula rate treatment, which means that the return on equity for these lines is typically calculated based on the costs the utility incurs, not the benefits the line provides.[117]

Order No. 1920 tries to address some of these issues by requiring utilities to engage in a right-sizing analysis in which they determine whether regional solutions could better address these needs, but we are skeptical that this reform will provide a sufficiently strong incentive for utilities to stop overinvesting in local projects. Order No. 1920 does not, for example, prevent incumbent utilities from determining which projects qualify for the immediate-needs exemption. Nor does it provide an adequate means of determining whether alternative solutions could more effectively address the transmission need, or that the utility engaged in forward-looking planning that would have allowed planning entities to assess regional solutions.[118] Another problem is that Order No. 1920 does not include financial carrots or sticks that strengthen financial incentives to pursue more cost-effective transmission solutions or discipline utilities that abuse exemptions to regional planning requirements. As a result, we expect that utilities will continue to be able to overinvest in non-regional projects.

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114. *See* Zack Hale, *FERC faults PJM for lack of transparency on transmission reliability projects*, S&P Global (Jun. 18, 2020), https://perma.cc/GJ29-A8AE (noting that utilities in PJM were took advantage of the exemption with unusual frequency, with PJM designating 241 projects as "immediate-needs" between 2015-2018, as compared to ISO-NE's 29).

115. *Asset Condition Projects and Process Improvements*, New England States Comm. on Elec. 2–3 (2023), https://perma.cc/7CD2-22ZB (pointing out that spending on Asset Condition projects increased from $58 million in 2016 to nearly $800 million in 2023). *See id.* at 3 (pointing out that Asset Condition Projects "are subjected to materially less regional review and scrutiny").

116. For more on the "immediate-needs" exception, see *supra* Section III.B.4 (discussing the pushback from RTO members against the removal of a federal right of first refusal).

117. *Primer on Transmission Formula Rates*, London Economics 1, 4 (2023), https://perma.cc/H3R9-WDXH.

118. While Order No. 1920 does require utilities to perform a right-sizing analysis, that is done by the utilities themselves and does not appear to involve a third-party check. We hope that the Commission gives the right-sizing requirement teeth in the Order No. 1920 compliance filings and in future rulemakings.

5. Carveouts to Siting Requirements

State siting laws exacerbate the problems caused by federal regulatory gaps. Siting laws pose a significant regulatory hurdle for transmission development. Approximately four of the eight-to-ten years needed to build new high-voltage projects involves navigating a state's approval process.[119]

Local oversight occurs mainly at the siting stage. State public utility commissions can deny CPCNs for a number of reasons, including that the transmission project is not necessary or beneficial.[120] However, carveouts to state siting laws render the siting and permitting process a relatively limited check on utilities' transmission investment decisions.

One reason for this is that most states simply do not require certificates of public convenience and necessity for certain types of projects. Specifically, projects that fall under a certain voltage threshold or are built on existing rights of way often do not need to receive a certificate of public convenience of necessity. For example, Arizona requires only those lines that transmit energy at or more than 115 kilovolts to get a certificate.[121] The threshold level in other states is higher: 138 kilovolts in Kentucky,[122] 200 kilovolts in California[123] and Nevada,[124] or 230 kilovolts in Florida[125] and Idaho.[126] As a result of these exemptions, utilities can minimize state-level review if they invest in small projects. Transmission owners can also avoid CPCN requirements by building on existing rights-of-way in some states.[127] Perhaps unsurprisingly, a significant percentage of lines that end up being built qualify for exemptions to state CPCN requirements. In Florida, for example, 93% of transmission lines (by length) are rated below 230 kilovolts.[128] In Idaho, 87% of lines fall below the 230 kV threshold that triggers CPCN review.[129]

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119. Liza Reed, *Transmission Stalled: Siting Challenges for Interregional Transmission* 4 (Niskanen Center 2021). Mention that there are other challenges here not about states. NEPA, BLM, etc. A line may provide a net benefit to consumers across the U.S., but be denied a permit because of citizen opposition, politics, or cost concerns from one specific state *See* Alexandra B. Klass & Elizabeth J. Wilson, *Interstate Transmission Challenges for Renewable Energy: A Federalism Mismatch*, 65 Vand. L. Rev. 1801, 1804 (2019). As a result, it is generally easier for developers to build local transmission lines—which require the consent of just one state, which is certain to benefit from the line—than it is to build regional or interregional lines, which bring along a larger administrative burden.
120. *See supra* Section II.B.
121. Ariz. Rev. Stat. § 40-360.
122. Ky. Rev. Stat. § 278.020.
123. Cal. Pub. Util. Code § 1001(a)–(b).
124. Nev. Stat. 704.860, 865.
125. Fla. Stat. § 403.522, 524.
126. Idaho Code §§ 61-526, 61-118, 61-516.
127. Ark. Admin. Code § 23-18-510(a)(1)–(2), 503; 220 Ill. Comp. Stat. §§ 5/8-406(b), 406.1.
128. U.S. Dep't. Homeland Sec., Geospatial Mgmt. Office, *U.S. Electric Power Transmission Lines* (Mar. 22, 2023), https://perma.cc/YF4K-D3RY; *see infra* Appendix.
129. *Id.*

There is some evidence that these exemptions create incentives for utilities to make inefficient investment decisions. Consider one example, where Florida Power & Light chose to limit the voltage on a proposed 176-mile line to 161 kilovolts, rather than 230, in what appears to have been an attempt to avoid having to go through the process of receiving a certificate of public convenience and necessity and the associated additional public scrutiny.[130] The 171 kV line was less efficient and seems to have led to cost increases,[131] but it avoided public and regulatory scrutiny that might have led to administrative delays or forced the utility to consider less lucrative alternatives.

In short, regulatory gaps to regional planning requirements allow utilities to make investment decisions that do not appear to maximize societal welfare. Regulatory scrutiny could result in transmission owners being forced to charge less. Or it could result in them being forced to invest in projects that are more onerous or less profitable. Or planners may require transmission owners to consider non-transmission alternatives such as storage or grid-enhancing technologies. To the extent that local projects avoid these risks, utilities are acting rationally in avoiding large projects that would trigger regional transmission planning processes and greater scrutiny from state regulators. And because these lines receive formula rate treatment, utilities earn a profit from these lines even though regulators and other stakeholders have little ability to make sure that proposed lines are cost-effectively addressing the region's transmission needs.

6. Carveouts to Cost Allocation Rules

A related challenge is that federal rate treatment does not adequately incentivize utilities that make cost-effective or socially beneficial transmission investments. FERC's reforms in Order Nos. 1000 and 1920 were meant to make cost allocation for regional projects less contentious, and in turn facilitate investment in more regional projects. But here, too, it does not appear that Order No. 1000 achieved these goals, or that Order No. 1920 fully remedies utilities' misaligned financial incentives.[132] Order No. 1000 required that costs be allocated commensurate with benefits received by investment. Transmission investment provides a broad and diverse set of benefits, not all of which lend themselves to easy appraisal.[133] In the years following Order No. 1000, transmission

130. Ivan Penn, *How a Florida Power Project Flew Under the Regulatory Radar*, N.Y. Times (May 31, 2022), https://perma.cc/R7RE-CR78.

131. A voltage of 161 kV is usual for lines less than five miles long, so as to reduce power loss. *See id.* ("The lower voltage, however, means the line loses energy over long distances without expensive equipment to support it, particularly in times of high demand.").

132. Specifically, while Order No. 1920 includes cost allocation reforms, it does not create strong financial incentives for utilities to pursue regional and interregional projects by, for example, increasing ROE for lines with a high benefit-to-cost ratio or reducing ROE for lines with a low benefit-to-cost ration.

133. Johannes Pfeifenberger, *21st Century Transmission Planning: Benefits Quantification and Cost Allocation*, Brattle 14 (2022), https://perma.cc/35WL-SJYR ("The wide-spread nature of

owners have brought a number of challenges to cost allocation methods. Some of these challenges have alleged that cost allocation methods apply to overly broad regions,[134] whereas others have alleged that cost allocation methods do not distribute costs across a sufficiently large set of beneficiaries.[135]

A central challenge is that states and utilities often cannot agree on how to allocate the costs of transmission.[136] In our view, the FPA requires the use of the beneficiary pays approach to cost allocation in which the costs of transmission are allocated to the customers who benefit from transmission projects. Nonetheless, although the beneficiary-pays approach by definition does not require states to pay for neighboring states' clean energy policies,[137] policymakers in states that have not made renewables a priority nevertheless fear that their ratepayers will be forced to bear some of the costs of other states' policy priorities. States and FERC Commissioners have also worried that cost allocation can be used "to decide when a state must pay for its neighbors' parochial public policy objectives," especially where "cost allocation . . . leaves customers in the [zone in which renewable energy is generated] paying a disproportionate share of the costs for the new or upgraded transmission that is used for exports."[138]

Legal and political disputes about how to allocate the costs of regional and interregional lines likely further contribute to overinvestment in local projects. When utilities use the local process, developers need only negotiate with one or a few parties, rather than the large number of stakeholders who participate in regional and interregional planning. In addition, costs are allocated entirely to one party, which obviates the need for an accurate quantification of the benefits of a project.

In fact, many local projects do not require that benefits be quantified at all. Local developers are guaranteed cost recovery because, under FERC's formula

transmission benefits creates challenges in estimating benefits and how they accrue to different users, which . . . complicates cost allocation.").

134. *See Illinois Commerce Commission v. FERC*, 756 F.3d 556, 564 (7th Cir. 2014) (rejecting a postage-stamp approach to cost allocation).

135. *See Old Dominion Elec. Coop. v. FERC*, 898 F.3d 1254, 1260–61 (D.C. Cir. 2018) (rejecting FERC's approval of a PJM amendment that prevented cost-sharing for two high-voltage projects and allocated costs entirely locally); *see also Long Island Power Auth. & Long Island Lighting Co. v. FERC*, 27 F.4th 705, 709–710 (finding that "[f]or over a decade, member utilities disputed how to allocate the cost of [regional] projects") (D.C. Cir. 2022).

136. *See* Macey & Mays, *The Law and Economics of Transmission Planning and Cost Allocation*, *supra* note 76.

137. *See id*.

138. Joint Pet. for Review, *City Utilities of Springfield, Mo. et al. v. FERC*, No. 23-1054 (D.C. Cir. Feb. 24, 2023) (Danly, Comm'r, dissenting). In another example, a proposal by MISO to allocate $10 billion in transmission investment on a postage-stamp basis spurred concerns from Mississippi that its ratepayers were subsidizing other state's renewable energy goals. *In re Midcontinent Independent System Operator, Inc.*, 179 FERC ¶ 61, 124 at ¶ 47 (2022); *see also* Cy McGeady, *Assessing Electric Transmission's Cost Allocation Dilemma*, Center for Strategic & Int. Studies, (Oct. 6, 2023), https://perma.cc/3X67-N2GT ("[S]ome state policymakers fear their ratepayers are paying for transmission that unlocks wind power projects needed for other state's policy goals.").

rate approach to cost recovery for transmission, developers automatically recover costs incurred in developing transmission, as well as an additional return on invested capital.[139] Although FERC reviews these filings for accuracy, there is a strong presumption in favor of rates being "just and reasonable," and revenue is based on utilities' costs—not on the benefits the lines provide.[140]

And it is difficult for consumer advocacy groups or third parties to challenge these investments. FERC has established a presumption of prudence for transmission investments, explaining that, where formula rate challenges are concerned, "prudence goes to the reasonableness of an expenditure on a defined input, not whether the input itself is appropriate."[141] As a result, the costs of local projects are typically automatically passed onto consumers, who have little opportunity to participate in project selection even though they are ultimately responsible for paying for these transmission investments.[142]

C. Transmission Owner Influence Over Regional Planning Processes

Another reason it is difficult to prevent utilities from overinvesting in local projects is that, even though RTOs and non-RTO transmission planners are supposed to have independent governance structures, regional planning processes are themselves onerous and heavily influenced by incumbent utilities.

139. *See generally Primer on Transmission Formula Rates*, London Economics (2023), https://perma.cc/H3R9-WDXH; Order On Formula Rate Protocols and Establishing a Show Cause Proceeding, 182 FERC ¶ 61,156, P. 3-6 (Mar. 16, 2023) (providing a history of FERC formula rate orders).

140. *See Comment of the Harvard Electricity Law Initiative* 1, 20, FERC Docket No. AD22-8-000 (Mar. 23, 2023) (arguing that "utilities' capital expenditures on local facilities have spiked, in part because Commission regulation does not hold utilities accountable for their decisions or expenditures" and that "[s]o long as the utility follows its own rate formula, it will recover every dollar it spends").

141. *Ameren Ill. Co.*, 162 FERC ¶ 61,025 at ¶ 28 (2018).

142. Automatic cost recovery provisions also create opportunities for utilities to obscure—and pass on—all sorts of expenditures. In a particularly egregious example, FirstEnergy improperly passed on millions of costs unrelated to service to consumers, including more than $1 million in lobbying expenses, and $19.4 million in "payments to . . . entities associated with an individual under investigation by FirstEnergy," for which it later entered into a deferred prosecution agreement. In the agreement, FirstEnergy acknowledged it had "through the acts of its officers, employees, and agents conspired with public officials and other individuals and entities to pay millions of dollars to and for the benefit of public officials in exchange for specific official action for FirstEnergy's benefit." *In re FirstEnergy Corp.* 20, Docket No. FA19-1-000 (2022); *id.* at 17 ("FirstEnergy identified eight lobbying payments, made between March 2017 and October 2019, amounting to a total of $26.5 million . . . [payments were] improperly accounted for as General and Administrative expenses ($0.65 million) and costs of electric plant in service ($0.85 million). Those expenses were then used to develop service rates charged.). By classifying these expenditures as operating expenses, FirstEnergy was able to automatically recover them from customers without much scrutiny. *See* Complaint, *United States v. Householder,* No. 1:20-MJ-00526 (S.D. Ohio Jul. 17, 2020).

1. RTO Governance

Consider RTO governance.[143] RTOs are governed by stakeholder committees, in which different classes of members (supply-side, load-side, and transmission-owning interests) are supposed to have an equal inputs.[144] To make sure no stakeholder group gains a disproportionate say in RTO matters, groups are generally given one "vote" per sector.[145] Often, incumbent interests such as generation, transmission, and distribution providers represent forty or even sixty percent of voting rights.[146] If new members join a member-sector, they get to vote. This means that individual participant voting power gets diluted as new participants enter the RTO. But note that this disproportionately affects the generation sector, where independent power producers are relatively free to enter the market. The legal entitlements that make it difficult for new transmission developers to enter the market also protect incumbent transmission owners' voting stake.[147]

Given the outsized role transmission and distribution companies have in RTO governance, it is perhaps unsurprising that RTOs have been reluctant to take steps to prevent transmission owners from overinvesting in local projects. In fact, even when RTOs have developed ambitious regional transmission plans, they have often done so in ways that protect incumbent financial interests. For

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143. For other works describing the grid's governance challenges, see Joel B. Eisen & Heather E. Payne, *Rebuilding Grid Governance*, 48 BYU L. Rev. 1057, 1062 (2023) ("It is time to contemplate more sweeping changes to promote the clean energy transition, and not settle for less. Until now, it has been all too convenient to make incremental progress."); Shelley Welton, Rethinking Grid Governance for the Climate Change Era, 109 Cal. L. Rev. 209, 214 (2021) ("This Article contends that U.S. grid governance must be redesigned to accommodate a new era of regulatory priorities that include responding to climate change.").

144. *See infra* Appendix; *see also* Christina E. Simeone, *Reforming FERC's RTO/ISO stakeholder governance principles*, 34 Elec. J. 106954, 2–3 (2021).

145. *See* Stephanie Lenhart & Dalten Fox, *Participatory democracy in dynamic contexts: A review of regional transmission organization governance in the United States*, 83 Energy Res. & Social Sci. 102345, 8 (2022) ("In general, RTOs uses sector-weighted voting in the highest-level members committee and allow parent committees to determine the voting mechanisms or other decision-making processes in subcommittees and lower-level venues."); *see also* Seth Blumsack & Kyungjin Yoo, *RTO governance structures can affect capacity market outcomes*, Proceedings of the Annual Hawaii International Conference on System Sciences 3087, 3089 (2020) (describing sector-weighted voting in PJM as "voting that gives equal weight to all five sectors. As a result, each sector gets 20% of the total voting score, and each sector's voting score represents a share of favoring votes of that sector excluding abstention votes. In other words, individual voters within the same sector share the one score and are inversely weighted by the number of voters of its sector.").

146. Simeone, *supra* note 144, at 3–4 (showing sector-weighted voting power by voting member).

147. Simeone, *supra* note 144, at 4 (showing voting member growth in PJM by sector, describing how vote dilution can result in suboptimal design of market rules that prioritizes incumbent interests over competitive outcomes); Stephanie Lenhart & Dalten Fox, *Participatory democracy in dynamic contexts: A review of regional transmission organization governance in the United States*, 83 Energy Res. & Soc. Sci. 102345, 7 (2022) (showing the share of members in sector categories by regional transmission organization).

example, in 2022, FERC approved MISO's plan to allow projects where at least 80% of the associated costs came from upgrades to existing infrastructure to bypass competitive bidding.[148] According to opponents of the proposal, this would prevent new transmission facilities valued at approximately $489 million from being eligible for competition in Tranche 1 of MISO's Long-Range Transmission Plan.[149] Customers "could expect to pay up to $146.7 million more in capital costs" as a result.[150] Although the MISO proposal clearly affected numerous stakeholders, the MISO board decided not to hold a stakeholder vote.[151] MISO's approach may well have reflected a necessary compromise to get projects in the ground, but it also highlights that, even when regions do agree on ambitious transmission investment, they often do so in ways that serve the interests of the incumbent firms that participate in RTO governance.

The bottom-up nature of RTO decision-making provides additional opportunities for transmission owners to control transmission investment. Most proposals that are eventually brought to stakeholder vote (the step that usually precedes the RTO's submission of the proposal to FERC for approval) arise from task forces or subcommittees charged with investigating specific topics and proposing solutions.[152] Although stakeholders theoretically have equal input in these committees, there is little oversight of low-level committees, and most participation in lower-level committees appear to consist primarily of large utilities that also have an outsized influence in RTO governance.[153] However, because lower-level committees do not use sector-weighted voting, larger sectors—especially supply-side sectors—have an easier time getting proposals through. These proposals then get vetoed at upper-level committees, where the same interests again have significant voting power.[154] All these problems are exacerbated by the fact that voting participation in RTO subcommittees appears to be quite low,[155] giving motivated members additional influence in determining which proposals come up for voting. A related challenge is that RTOs' heterogeneous

148. *In re Midcontinent Independent System Operator*, 180 FERC ¶ 61,040 at ¶ 58 (Jul. 26, 2022).

149. *Id.* ¶ 32 (detailing NextEra's protest to MISO's proposal).

150. *Id.*

151. *Id.* ¶ 20 ("MISO claims that, given the need to move forward expeditiously and provide maximum certainty to all affected parties, and due to the limited scope of the Proposal, MISO's decision to proceed without vetting the Proposal in the MISO stakeholder process is reasonable.").

152. *See* Lenhart & Fox, *supra* note 146, at 8 (2022) ("Communication about proposed rule changes typically begins in more informal subcommittee, workgroup, or task force discussions …[and] then proceeds to standing committees.").

153. Simeone, *supra* note 144, at 4 (showing member participation in PJM).

154. *Id.* (describing this process in PJM); *see also* Kyungjin Yoo & Seth Blumsack, *Can capacity markets be designed by democracy*, 53 J. Reg. Econ. 127, 148 (2018) ("We expect that the current structure of the stakeholder process in PJM makes the passage of capacity market reforms through the stakeholder process virtually impossible… [because] heterogeneous stakeholders with opposing interests [will fail] to develop passable market rules and protocols.").

155. *See id.*

membership rosters can make it difficult for high-level members' committees to provide a meaningful forum for decision-making.[156]

2. Non-RTO Governance

Governance also contributes to suboptimal planning in non-RTO regions. Utilities in much of the country never joined an RTO. Yet these utilities must still engage in Order No. 890 and 1000-compliance regional transmission planning. To do so, they participate in non-RTO regional transmission planning entities such as Southeastern Regional Transmission Planning (SERTP), NorthernGrid, WestConnect, and WEPP. Lacking full RTO status, these planning regions do not need to meet all the same governance safeguards that RTOs do. SERTP, which is composed of utility companies in the southeast,[157] is the largest non-RTO/ISO joint planning entity, and it highlights the difficulties faced by these non-RTO regions. SERTP was created to comply with FERC Order No. 890 in 2007, and subsequently, with Order No. 1000.[158] From the start, FERC has been concerned that southern transmission owners exerted too much influence over the SERTP planning process. In fact, when utilities first sought to create SERTP, they proposed an enrollment process that would have prohibited voluntary enrollment in the SERTP region.[159] Utilities would have been able to enroll in SERTP only if they could produce evidence of a "statutory or OATT obligation to ensure that adequate transmission facilities exist within a portion of the SERTP region."[160] In other words, utilities could only join SERTP if they already owned transmission in the Southeast.

Since SERTP was formed, all its regional plans have essentially aggregated the local plans submitted by the incumbent utilities that compose the SERTP board. In fact, there is reason to be skeptical that SERTP acts independently of the southeast utilities that created the transmission planning entity in response to Order No. 890. Rather than evaluate projects itself,[161] SERTP publishes projects

156. *See* Vince Duane & Tony Clark, *Who Owns the RTO?* 13 (Nov. 2021), https://perma.cc/DT4E-V2EP ("With all these interests banging at the door of the member-driven RTO, it's no surprise [that some claim] they can't get in or, more likely find that once inside, it's a crowded room where their voice is lost in the general cacophony. . . .").

157. SERTP, *About Us,* https://perma.cc/ZP3A-J6PN ("The SERTP has expanded several times, both in the scope and in the size of the region, since its initial voluntary formation and now includes the following Sponsors: Southern Company (SCS), Dalton Utilities, Georgia Transmission Corporation (GTC), the Municipal Electric Authority of Georgia (MEAG), PowerSouth, Louisville Gas & Electric Company and Kentucky Utilities Company (LG&E/KU), Associated Electric Cooperative Inc. (AECI), the Tennessee Valley Authority (TVA), and Duke Energy").

158. SERTP, 2016 Regional Transmission Planning Analyses 3 (2016), https://perma.cc/BLQ9-Q9MV. *See also Lousiville Gas & Elec. Co.*, 144 FERC ¶ 61,054 ¶ 6 (2013).

159. *In re SERTP*, 147 FERC ¶ 61, 241 ¶ 28 (Jun. 19, 2014).

160. *Id.*

161. SERTP, 2015 Regional Transmission Planning Analyses 1 (2015), https://perma.cc/4E5S-Z7QF (describing how only SERTP *sponsors*, i.e. member utilities, conduct planning and evaluate projects).

Transmission Owners are planning to develop, at which point stakeholder members of SERTP can respond to the plans those transmission owners' submitted and propose alternatives.[162] SERTP only evaluates proposed projects in relation to the submitted alternatives. It does not conduct top-down forward-looking planning. Alternatives proposals are rarely selected. In 2021, for example, only three potential alternative transmission projects were evaluated, and none of them were found to be more efficient than the initial projects submitted.[163] The same was true for 2020,[164] 2019 (five alternatives evaluated, none found to be more efficient),[165] 2018,[166] 2017 (seven alternatives evaluated, none found to be more efficient),[167] and 2016 (nine projects alternatives, none found to be more efficient).[168]

This is partly because SERTP defines benefits narrowly. Under its tariff rules, SERTP can evaluate projects along just one metric: avoided transmission cost. Avoided transmission costs, defined as "the transmission costs that the Beneficiaries would avoid due to their transmission projects being displaced by the transmission developer's proposed transmission project,"[169] do not account for, among other things, reliability and economic benefits of alternative transmission investments. Further, the transmission owner itself is the entity that must consider alternatives to its own proposed projects, which puts the transmission owner in a position to propose only alternatives that do not threaten its financial interests.[170] For example, southern utilities appear to primarily, and perhaps exclusively, consider alternatives that are within their own service territories. As a result, utilities and regulators never consider whether lines that cross two or more utility service territory would be a more cost-effective means or provide greater benefits.

SERTP's planning process also favors incumbents in other ways. For example, SERTP refuses to consider more than ten years' worth of benefits of a project in any single planning study.[171] The start- and end-dates of planning studies

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162. *Id.*
163. SERTP, 2021 Regional Transmission Planning Analyses 16 (2021) ("none of the three (3), new potential transmission project alternatives evaluated were found to be more efficient or cost effective as compared to the transmission projects included in the 2021 regional transmission expansion plan"), https://perma.cc/C6YF-XQ2X.
164. SERTP, 2020 Regional Transmission Planning Analyses 16 (2020), https://perma.cc/AR9M-DRF7.
165. SERTP, 2019 Regional Transmission Planning Analyses 20 (2019), https://perma.cc/W9KU-DPWX.
166. SERTP, 2018 Regional Transmission Planning Analyses 16 (2018), https://perma.cc/BLQ9-Q9MV.
167. *Id.* at 24.
168. *Id.* at 28.
169. Louisville Gas & Electric Co., *Tariff – Attachment K* § 26, FERC Docket No. ER13-897 (Feb. 7, 2013). Note that SERTP does not submit tariff filings to FERC itself, because it is not an RTO.
170. *Id.* at § 26.1.
171. Simon Mahan, *Gridlocked: Planning Failure with the Southeastern Regional Transmission Planning Process*, Southern Renewable Energy Ass'n (Dec. 20, 2023), https://perma.cc/

are fixed. This means that, if a project gets proposed halfway through the planning period, SERTP would consider only five years of benefits. If a project gets proposed in the ninth year, just one year of benefits would be evaluated.[172]

Altogether, while Order No. 1000 encouraged top-down planning, SERTP employs something that looks more like a "bottom-up" planning process.[173] It has effectively handed over most substantive planning responsibilities to its member organizations, who all have a vested interest in maintaining the status quo and increasing barriers to entry for alternative project proposals. Given this context, it is unsurprising that SERTP has not chosen a single alternate proposal since 2016.[174]

Another challenge is that southeast utilities often control data related to their planning and investment decisions. Although members are supposed to report which assumptions they used in the development of their planning processes, they are not bound by any specific method of collecting or processing data.[175] This appears to create opportunities for gamesmanship, such as Duke Energy using phantom "proxy" generators to hide retirements in its models, or LGEKU refusing to report planned retirements even after they had been approved by the responsible Public Service Commission.[176] Without reliable data or consistent assumptions, the whole planning process becomes vulnerable to manipulation.

Thus, although transmission planners are supposed to evaluate the most efficient means of meeting the country's transmission needs, the rules and regulations that govern transmission planning and cost allocation authorize carve-outs to the regional process that allow bottom-up planning in which transmission owners can unilaterally determine which lines to build.[177]

LA3P-2MN2 ("SERTP only evaluates 10 years' worth of benefits from the time the study begins . . . Put another way, if a transmission project gets added in the 9th year of a 10-year model, only 1-year of benefits are measured.").

172. *See id.*

173. *See Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, 87 Fed. Reg. 26504, 26521 (May 4, 2022) (to be codified at 18 C.F.R pt. 35).

174. Mahan, *supra* note 171

175. *See id.* ("When asked about [data] discrepancies, SERTP utilities explained that each utility comes up with its own methodologies for sharing data, or not. There are no rules regarding what gets included, or not.").

176. *Id. Compare* Ethan Howland, *Kentucky PSC Partly Approves PPL's $2.1B Plan to Retire Coal, Add Gas, Solar and Storage*, Utility Dive (Nov. 8, 2023), https://perma.cc/U5T3-L8VD, *with* SERTP, *Annual Transmission Planning Summit & Assumptions Input Meeting* 188, (Dec. 4, 2023,) https://perma.cc/W7M3-K2CD ("LG&E/KU has no generation assumptions expected to change throughout the ten-year planning horizon for the 2024 SERTP Process.").

177. *See generally* Shelley Welton, The Hamilton Project, Governing the Grid for the Future: The Case for a Federal Grid Planning Authority 8–9, (2024) (describing how incumbent utilities are able to leverage their influence to build transmission that solely benefits them, to the detriment of newer entrants or more efficient generation resources).

RTO Governance Structures.[178]

	CAISO	ISO-NE	MISO	NYISO	PJM	SPP
Board Structure	5 members, 3-year terms	10 members, 3-year terms	10 members, 3-year terms	10 members, 4-year terms	10 members,[179] 3-year terms	10 members, 3-year terms
Selected Board Duties	Approves regulatory filings, select CEO & President, oversee market monitoring.	Assign members to standing committees.	Assign members to standing committees.	Approves regulatory filings.	Approves regulatory filings; "reviews and decides upon all major changes and initiatives proposed by committees and user groups."[180]	Approves regulatory filings.[181]
Board Quorum	2/3rds of directors	Five or more	Five or more	Six or more	Five or more	Six or more

178. *See* Christopher A. Parent et al., *Governance Structure and Practices in the FERC – Jurisdictional ISOs/RTOs* 3–8, NESCOE (Feb. 2021), https://perma.cc/Z32T-2H56.
179. 9 voting members and the PJM president, who is a non-voting member. *See Governance*, PJM, https://perma.cc/84KN-KT7N.
180. Id.
181. Items that are approved through the stakeholder process and not appealed specifically to the SPP board do not need to be reviewed and approved by the board. *SPP Board of Directors Policy Statement Authorization of Regul*atory Filings, SPP (Dec. 4, 2018), https://perma.cc/Q5RP-3WH6.

	CAISO	ISO-NE	MISO	NYISO	PJM	SPP
Senior Committee Sectors	N/A	Generation; Transmission; Supplier; Alternative Resources;[182] Publicly Owned Entity; End User	Competitive Transmission Developers; Independent Power Producers and Exempt Wholesale Generators; Municipals, Cooperatives, and Transmission Dependent Utilities; Power Marketers and Brokers (PM); Transmission Owners; End Users; Coordinating Members[183]	Generation Owners; Other Suppliers; Transmission Owners; Public Power and Environmental Parties; End Use Consumers	Transmission Owners; Generation Owners; Electric Distributors; End-Use Customers; Other Suppliers	Transmission Owning Members; Transmission Using Members
Senior Committee Weights		Sector-Weighted	Sector-Weighted	Sector-Weighted	Sector-Weighted	Each sector votes separately with the result for that sector being a percent of approving votes to the total number of Members voting. An action is approved if the average of these two percentages is at least 66%[184]

182. The "Alternative Resources" sector is in turn divided into three subsectors: Renewable Generation; Distributed Generation; and Load-Response. *See Second Restated NEPOOL Agreement*, NEPOOL 27–29 (Jul. 1, 2008), https://perma.cc/VU42-D2BP.

183. A Coordination member is an organization which, being legally unable to transfer operational control of its transmission facilities to MISO, has entered into coordination or agency agreements with MISO. Currently, this sector is wholly comprised of Manitoba Hydro, a Canadian vertically integrated utility. See S*ector Guidelines for Membership and Participation – Coordinating Member Sector*, MISO, https://perma.cc/934D-FND9.

184. *Governing Documents Tariff – Bylaws* ¶ 3.9.1, Southwest Power Pool (Apr. 30, 2020), https://perma.cc/P7M4-C4Q6.

IV. Solutions

The problems described in the previous section suggest a need to reevaluate the entire framework for planning, paying for, and permitting new transmission lines. While we think reforms to the regional planning processes could help lead to more sensible transmission investment, we ultimately think the federal regulators need to directly intervene to plan, permit, and pay for high-voltage lines. This Part explains how to do so under current regulatory authority and with legislative reforms.

A. The Grid Deployment Office (GDO)

Despite the fact FERC is often seen as the primary federal transmission regulator, recent legislation has given the Grid Deployment Office (GDO) significant authority to help plan, permit, and pay for high-voltage transmission. Aggressive use of GDO's authorities could put the Office in a position to address the country's most pressing transmission needs.

In August 2022, the Biden administration created the GDO, a new administrative agency tasked with, among other things, "increas[ing] grid resilience at the transmission and distribution levels."[185] The GDO took over the Transmission Needs and National Transmission Planning Studies, and was given a broad delegation of powers by the Department of Energy.[186] The Office was granted authority to exercise multiple sections of the Federal Power Act.[187] Most importantly, however, is the authorities it received under the Infrastructure Investment and Jobs Act (IIJA),[188] which authorizes the GDO to oversee the Transmission Facilitation Programs.[189] As we discuss below, altogether these authorities allow the GDO to identify where more transmission is needed, provide financial security to transmission developers that build regional lines, and, in some circumstances, facilitate siting and permitting of new lines.

1. Financing Grid Expansion

The GDO has authority to provide fairly meaningful financial support for high-voltage lines. Specifically, the IIJA's "Preventing Outages and Enhancing the Resilience of the Electric Grid" program establishes a system of grants for transmission owners and other eligible entities who carry out activities that "increase the ability of the eligible entity to reduce the likelihood and

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185. Grid Deployment Office, *About Us*, U.S. Dep't of Energy, https://perma.cc/4KMJ-29EL.
186. Dep't of Energy, *Redelegation Order No. S3-DEL-GD1-2023* § 1.9 (2023).
187. *Id.*
188. Dep't of Energy, *Redelegation Order No. S3-DEL-GD1-2023* § 1.10 (2023); Infrastructure Investment and Jobs Act (hereinafter "IIJA"), Pub. L. No. 117-58, 135 Stat. 429 (2021).
189. Dep't of Energy, *Redelegation Order No. S3-DEL-GD1-2023* § 1.10 (2023).

consequences of disruptive events."[190] The statute defines disruptive events broadly to include all those "in which operations of the electric grid are disrupted, preventively shut off, or cannot operate safely due to extreme weather, wildfire, or a natural disaster."[191] Grants can support a variety of activities, though GDO cannot use these grants to support construction of new generation facilities, cybersecurity, or battery storage facilities.[192]

The Transmission Facilitation Program provides another means through which GDO can provide financial support for new transmission investment. The program requires the GDO to establish a "transmission facilitation fund." This fund can be used to administer the transmission facilitation fund in one of three ways—through capacity contracts with developers, direct loans to developers, or through the use of public-private partnerships in which DOE plays a direct role in constructing the line.[193] Capacity contracts commit the Office to purchasing a percentage of proposed capacity of a transmission line, with the intent to "increase[e] the confidence of additional investors, encourag[e] additional customers to purchase transmission line capacity, and reduc[e] the overall risk for project developers."[194] GDO serves as an "anchor tenant," breaking through the chicken-and-egg problem wherein transmission developers wait for purchase commitments from generation developers, and vice versa, resulting in no transmission being built. Alternatively, the Office can directly participate in the construction and operation of a transmission project together with a private partner.[195] Crucially, when a federal agency enters into a public-private partnership in which it acquires land directly, it has siting authority.[196] As a result, the public-private partnership option allows GDO to exercise eminent domain authority and thus avoid procedural delays caused by state CPCN requirements.

For the transmission facilitation program specifically, GDO may—without further appropriation—borrow up to $2.5 billion to support transmission investment.[197] The GDO can also access an additional $2 billion through

190. IIJA, Pub. L. No. 117-58 § 40101(c)(1)(B)(ii) (2021).

191. *Id.* § 40101(a)(1).

192. *Id.* § 40101(e)(2)(A).

193. *Id.* § 40106(e).

194. Grid Deployment Office, *Transmission Facilitation Program first Round Selection*, Dep't of Energy (Oct. 30, 2023), https://perma.cc/HRD4-HDPV.

195. *IIJA*, Pub. L. No. 117-58 § 40106(h).

196. 40 U.S.C. § 3113 ("An officer of the Federal Government authorized to acquire real estate for the erection of a public building or for other public uses may acquire the real estate for the Government by condemnation, under judicial process, when the officer believes that it is necessary or advantageous to the Government to do so."); Albert Hanson Lumber Co. v. United States, 261 U.S. 581, 587 (1923) ("The authority to condemn conferred by the [Condemnation Act] extends to every case in which an officer of the government is authorized to procure real estate for public uses."). For a discussion of these authorities, *see* Avi Zevin et al., *Building a New Grid without New Legislation: A Path to Revitalizing Federal Transmission Authorities*, 48 Ecol. L. Q. 169 (2021).

197. *Id.* § 40106(b), 40106(d)(2).

the Transmission Facility Financing Program ("TFF"), which provides direct loans for eligible transmission projects built in national interest electric transmission corridors (NIETCs).[198] Beyond that, the GDO is allowed to recover the cost of any facilitation activities engaged in from the entities receiving the benefit of the facilitation activity, either directly or through rates charged for the use of transmission capacity.[199] This means that the GDO can recover its expenditures, freeing funds so that it can continue awarding grants.

Still, it would be helpful if Congress authorized GDO to provide additional financial support for high-voltage regional and interregional projects. GDO's ability to provide financial support for new transmission projects is currently limited by congressional appropriations. Major transmission lines typically cost several billion dollars.[200] With only $2.5 billion in accessible loans ($4.5 billion if one includes TFF), the GDO can only support a limited number of projects before exhausting its available borrowing limit.

But even without additional legislation, GDO could support a larger number of projects by shifting debt off of the GDO's balance sheet, either by selling the debt to the developer or to third-party investors. Since the GDO is authorized to recover its costs, securities backed by GDO-supported lines are likely to present attractive investment opportunities to third-party investors. By expeditiously moving debt from its balance sheet, the Office could significantly increase the rate at which it could finance new transmission projects.

A second limit is that some of the Office's authority can be exercised in only limited circumstances. For example, to enter into public-private partnerships, the GDO must determine that the project is located in an area designated as a NIETC, *or* is necessary to accommodate "an actual or projected increase in demand for electric transmission capacity across more than 1 State or transmission planning region."[201] Still, because the GDO itself can both designate NIETCs[202] and find that there is or will be an increase in demand for transmission capacity in two or more states,[203] those requirements should be less onerous than existing regional and interregional planning processes.[204]

In our view, the GDO could use this authority aggressively to provide financial support and streamline siting for new transmission projects. For example, in addition to prospectively designating NIETCs or identifying

198. *Inflation Reduction Act*, Pub. L. No. 117-19 § 50151 (codified at 42 U.S.C. 18715).

199. *IIJA*, Pub. L. No. 117-58 at § 40106(d)(4)(A).

200. *See, e.g.*, Ryan Dezember, *Hudson River Hydropower Transmission Line Cleared for Construction*, Wall St. J., https://perma.cc/2P98-8WKQ (Nov. 30, 2022) (estimating the cost of a new high-speed transmission line in New York at $6 billion).

201. *Id.* § 40106(h)(1).

202. *See* U.S. Dep't of Energy, S3-DEL-GD1-2023, *Redelegation to the Director, Grid Deployment Office* § 1.9(C) (Apr. 10, 2023) (delegating the authority to conduct the NEEDS study, which designates NIETCs, to the GDO).

203. *Id.* § 1.9.

204. *See infra* Section IV.C.4 (explaining FERC's backstop siting authority in NIETCs).

transmission needs, the Office could allow transmission owners themselves to propose NIETCs or suggesting areas that need additional transmission investment. Although GDO would still have to conduct an evidentiary hearing to determine that the proposed line is responding to a genuine need, this approach would shift some of the work to transmission owners and therefore reduce the administrative burden GDO faces in planning a more integrated transmission system.[205]

With sufficient political will, the GDO could effectively bypass the parochial transmission planning process described in Section III entirely. When the Office pays for transmission outright or authorizes cost recovery for new lines, it obviates the need for contentious cost allocation proceedings. When it designates NIETCs or finds that a project will meet existing or future demand for transmission, it identifies where transmission will be built in a process that closely resembles transmission planning. And when it designates NIETCs or enters into public-private partnerships, it provides a mechanism for exercising federal eminent domain that reduces the likelihood that states will block transmission projects by denying them CPCNs.

2. *Siting and Permitting*

The GDO could also streamline the siting and permitting of new transmission lines. One way to do this is by using its eminent domain authority. This would require aggressive use of the public-private partnership.[206] When the GDO enters into a public-private partnership to support transmission, it becomes a part-owner of the line.[207] In such circumstances, it could use TFP funds to acquire land directly, which gives it the right to exercise eminent domain authority under Section 3113 of the Condemnation Act.[208]

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205. This is especially important given the challenges regulators have faced in acquiring date relevant to transmission planning. *See* U.S. Dep't of Energy, Nat'l Transmission Needs Study (Oct. 2023), https://perma.cc/7LZC-B698 ("[T]here are gaps outside of RTO/ISO regions where information regarding the economic value of congestion is not available; these gaps do not reflect the absence of transmission needs but rather the absence of market data with which to calculate price differentials"). Incumbents are understandably reluctant to share data related to the value of transmission, given the many risks they face from a more integrated transmission system.

206. 50 Pub. L. 726, 40 U.S.C. § 3113.

207. *IIJA*, Pub. L. No. 117-58 § 40106(e)(1)(C) (stating that the GDO may "participate with an eligible entity in designing, developing, constructing, operating, maintaining, or owning an eligible [transmission] project").

208. 40 U.S.C. § 3113 ("An officer of the Federal Government authorized to acquire real estate for the erection of a public building or for other public uses may acquire the real estate for the Government by condemnation, under judicial process, when the officer believes that it is necessary or advantageous to the Government to do so."). The Department of Energy has previously used eminent domain when partnering with transmission developers

A second way to facilitate siting would be for the GDO to coordinate with FERC to provide developers with federal siting authority within NIETCs.[209] If a state has either denied or withheld approval to site a new planned line in a NIETC, FERC can step in to authorize the siting itself and allow the developer to use federal eminent domain authority.[210]

B. Incorporate Existing Studies Into Transmission Planning

Another way to improve transmission planning is to make better use of existing transmission studies. Different government and private entities—particularly the Department of Energy and the North American Electric Reliability Corporation (NERC)—are responsible for studying the benefits of an expanded transmission system. In the past year, DOE and NERC have published studies showing that additional transmission could reduce costs and improve reliability.[211]

FERC and DOE should incorporate these studies into existing planning processes. For example, FERC should require RTOs and regional transmission planning entities to consider planning needs identified by DOE in regional and interregional transmission planning. One way to increase support for large transmission investments would be for DOE to solicit proposals that address the transmission needs it has already identified. A more ambitious approach would be for GDO to ask developers to propose NIETCs in these areas such that FERC could site lines that address known reliability and economic challenges. Doing so could reduce the need for redundant studies by regional transmission planners and take advantage of existing studies to provide the economic justification for transmission expansion. If transmission planners do not address the needs that DOE and NERC have already identified, they would have to explain that decision. Ideally, this requirement would cause transmission planners to address known congestion and reliability issues. At the very least, it would increase information available to regulators and litigants about why certain transmission needs are being met and why others are not.

C. The Federal Power Act

The FPA provides FERC with a wide array of tools to encourage transmission development. FERC has employed its authority conservatively, but more aggressive options are available. If the political will to enact change is there, the

under § 1222 of the Energy Policy Act of 2005. *See United States v. 14.02 Acres of Land More or Less in Fresno County*, 547 F.3d 943, 948 (9th Cir. 2008).

209. *See supra* Section IV.C.4 (discussing FERC's siting authority in NIETCs).

210. *See* Federal Power Act § 216(b), 16 U.S.C. § 824p(b)(1)(A)-(C).

211. *See* U.S. Dep't of Energy, Nat'l Transmission Needs Study, *supra* note 205; Dep't of Energy, National Transmission Planning Study – Conclusions, *supra* note 19; NERC Interregional Transfer Capability *supra* note 35.

FPA grants FERC significant latitude to incentivize transmission development in a way that furthers decarbonization and reliability goals.

1. § 216 & National Interest Electric Transmission Corridors ("NIETCs")

The Federal Power Act gives the Secretary of Energy the authority to conduct surveys once every three years meant to identify transmission capacity constraints and congestion.[212] The Secretary may use the results from these surveys to designate geographic areas that "[experience] electric energy transmission capacity constraints or congestion that adversely affects consumers" or are expected to experience such constraints as a NIETC.[213] Once an area is designated as a NIETC, FERC may issue construction permits for electric transmission facilities in that area, if it finds that those who have siting authority have not used it,[214] and that:

> (1) the facilities to be authorized by the permit will be used for the transmission of electric energy in interstate commerce;
> (2) the proposed construction or modification is consistent with the public interest;
> (3) the proposed construction or modification will significantly reduce transmission congestion in interstate commerce and protect or benefit consumers;
> (4) the proposed construction or modification is consistent with sound national energy policy and will enhance energy independence; and
> (5) the proposed modification will maximize, to the extent reasonable and economical, the transmission capabilities of existing towers or structures.[215]

FERC can exercise siting authority when these conditions are met. As discussed, the NIETC designation requires that DOE find that capacity constraints or congestion is negatively affecting consumers. In our view, this requirement should not prevent the aggressive use of the NIETC designation, since congestion is an issue in nearly every RTO in the country, save for ISO-NE.[216] Yet the Department of Energy has been reluctant to "identif[y] transmission congestion conditions that would merit proposing the designation of National Corridors."[217]

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212. *Id.* § 216(a)(1).
213. *See id.* §216(a)(2).
214. *Id.* § 216(b)(i)(a)(1)(A)–(C).
215. *Id.* § 216(b)(2)–(6).
216. U.S. Dep't of Energy, National Electric Transmission Congestion Study 16–18 (Sep. 2020), https://perma.cc/U82N-D3QT (detailing congestion costs by RTO over time).
217. *Id.* at vi. This may be changing, as DOE has in the past year begun designation NIETCs. *See iden-Harris Administration Announces Initial List of High-Priority Areas for Accelerated Transmission Expansion* (May 8, 2024), https://perma.cc/JQ2M-NA5R. FERC has also taken steps to make backstop siting authority less burdensome. *See* Order No. 1977,

Nothing is stopping the Department from changing that conclusion—it is its own arbiter in making this determination. Designating NIETCs would give FERC broad authority to grant siting rights in places that have suffered from underinvestment in regional transmission projects and address congestion costs that negatively affect ratepayers.

Although DOE's and FERC's authority to designate NIETCs and exercise backstop siting authority have long been limited,[218] in the past few years, Congress intervened to strengthen federal authority to use the NIETC process to designate NIETCs.[219] Now that states are no longer able to veto projects in NIETCs, DOE and FERC should designate NIETCs aggressively to promote transmission development.

2. § 202

Section 202 allows FERC to divide the country into regional districts for the voluntary interconnection of transmission and generation facilities, and then charges the Commission with the "duty . . . to promote and encourage . . . interconnection and coordination within each such district and between such districts."[220] To do so, the Commission may, "upon application of any State commission or of any person engaged in the transmission or sale of electric energy" order a public utility "to establish physical connection of its transmission facilities with the facilities of [another] engaged in the transmission or sale of electric energy . . . ," provided that this does not place an "undue burden" on the utility, and that the Commission does not "compel the enlargement of generating facilities" or impair the utility's ability to render service to its customers.[221]

Applications for Permits to Site Interstate Electric Transmission Facilities, 187 FERC ¶ 61,069 (May 13, 2024), https://perma.cc/8U5V-TERE

218. NIETCs as a tool for promoting transmission development have been hamstrung since the Fourth Circuit's decision in *Piedmont Env't Council v. FERC,* F.3d 304 (4th Cir. 2009). There, the Court effectively gave states veto rights over FERC's permitting authority under § 216(b)(1). *Id.* at 313 ("the statute does not give FERC permitting authority when a state has affirmatively denied a permit application within the one-year deadline."). The Ninth Circuit further limited federal power in the NIETC process two years later, finding that the Department of Energy must "[engage] in meaningful consultation with the States" prior to releasing a Congestion Study Cal. Wilderness Coal. v. U.S. Dep't Energy, 631 F.3d 1072, 1088 (9th Cir. 2011).

219. Specifically, the Infrastructure Investment and Jobs Act clarifies that FERC has authority to site transmission projects where a state commission either has not made a determination on a siting application within one year, has "conditioned its approval in such a manner that the proposed construction or modification will not significantly reduce transmission capacity constraints or congestion," or has "denied an application seeking approval pursuant to applicable law." Pub. L. No. 117-58 § 40105 (2021) (amending 16 U.S.C. 824).

220. Federal Power Act, 16 U.S.C. § 824a(a) (2015).

221. *Id.* § 202(b).

Section 202 therefore allows FERC to directly order utilities to build specific transmission projects, so long as either a state official or a market participant requests that it do so. FERC could use Section 202 to work with new market entrants to create alternative processes for identifying transmission solutions. If it used this authority directly, it could solicit proposals, likely based on needs identified by DOE and NERC, and then direct incumbent utilities to develop the transmission infrastructure required for new generators to connect to the grid. Similarly, state officials could work with FERC to request that interregional transmission projects be built to ensure reliability.

3. § 219

FERC also has significant authority to authorize cost recovery for high-voltage lines. This is because Section 219 of the FPA requires FERC to promulgate a rule establishing incentive-based rates for transmission that "benefit[s] consumers by ensuring reliability and reducing the cost of delivered power by reducing transmission congestion."[222] As we have explained, formula rate treatment for transmission guarantees a return on local investments, regardless of the benefits secured.[223] The return they receive is based primarily on expenditures.[224] In our opinion, formula rates are partially to blame for the consistent overinvestment in local transmission projects over the past decade.[225] To spur more productive transmission investments, the structure of formula rates should be revised so as to incentivize lines that produce measurable benefits to ratepayers.

One way to do this would be for FERC to offer incentive payments that are based on the tangible benefits new lines provide.[226] Although FERC has already established incentive-based rate treatment for certain lines,[227] it has applied this authority too broadly. As we explained in Section III.C, Section 219 currently rewards utilities for participating in an RTO but does not tie incentives to the benefits a line creates.[228] That is because under Order No. 679, utilities are rewarded simply for participating in an RTO. In our opinion, FERC should

222. 16 U.S. Code § 824s(a).

223. *Comment of the Harvard Electricity Law Initiative*, *supra* note 140, at 20.

224. *Id.*

225. *See supra* Section III.B (discussing the problems intrinsic to formula rates); *see supra* Section III.A (discussing overinvestment in local lines); *see also* Lieberman, *supra* note 81, at 7; *Transmission Planning and Cost Management: Technical Conference* 224:7-24, FERC, Docket No. AD-22-8-000 (Oct. 6, 2022) (comment by Joshua Macey) (discussing perverse incentives created by formula rates).

226. Under § 219(c) of the FPA, FERC has authority to establish incentive-based rates to spur transmission investment. Federal Power Act, Pub. L. No. 117-58 § 219(c) (codified at 16 U.S.C. § 824s(c)).

227. *See* FERC Order No. 679, supra note 95.

228. *See supra* Section III.C.

both eliminate the presumption of prudence that currently applies to transmission investment and narrow the scope of Section 219 incentive-based rate treatment. For example, Section 219 should provide financial incentives for lines that go through the Order Nos. 1000 and 1920 planning process but not to all projects built in RTOs. FERC should also stipulate that lines are eligible for Section 219 incentives only if the benefit-to-cost ratio is above a certain threshold. Doing so would ensure that utilities have a financial incentive to go through the regional planning process and pursue projects that genuinely benefit the electric system.

Section 219 also allows FERC to authorize cost recovery for lines built in NIETCs. More specifically, Section 219(b)(4)(B) instructs FERC to provide cost recovery for "prudently incurred costs related to transmission development" in NIETCs. Even though FERC has used FPA Sections 205 and 206 to regulate cost allocation,[229] this authority is nevertheless helpful because it establishes that lines constructed in NIETCs should presumptively be able to recover their costs. Section 219(b)(4)(B) thus reduces the evidentiary burden the Commission would otherwise face when allocating the costs of transmission. Although interested parties can challenge the decision to designate a NIETC, they cannot litigate every cost allocation decision in designated transmission corridors.

4. A National Transmission Planning Authority

The most direct and ambitious way for FERC to promote grid development would be to create a National Transmission Planning Authority ("NTPA") using its § 206 authority. Such an NTPA would be in charge of planning the entirety of the national transmission system and be able to leverage the various benefits that arise from coordinated *interregional* planning in a way that RTOs are not able or willing to. The NTPA could either augment or wholly replace existing RTOs.

While ambitious, the development of an NTPA would be in line with FERC policy over the past three decades. The initial impetus behind the formation of RTOs was FERC's recognition that transmission developers favored their own generating units and unduly discriminated against competitors, leading to higher prices and worse reliability for consumers.[230]

Under § 206 of the FPA, FERC may "determine the just and reasonable rate, charge, classification, rule, regulation, practice, or contract to be . . . observed and in force" if it determines that the status quo has led to unjust or unreasonable rates.[231] Given the well-documented problems with transmission today,[232] FERC should be able to meet this standard.

229. *See* Order Nos. 1000 and 1920.

230. *See Order No. 888*, *supra* note 44, at 21541 (recognizing that transmission providers can "use monopoly power over transmission to unduly discriminate against others.").

231. 16 U.S.C. § 824e(a).

232. *See supra* Section III.

That said, creating an NTPA would create formidable challenges. The effort would almost certainly be met with well-funded legal challenges, brought in courts that are increasingly skeptical of aggressive administrative intervention.[233] Beyond these initial challenges, FERC would have to tackle the thorny question of governance for the NTPA. The Commission would have to decide which entities would control the new Authority, and which stakeholder processes to put into place to ensure the NTPA remains accountable to all interested parties. Finally, FERC would need to somehow persuade reluctant utilities and transmission owners to share their troves of congestion and grid use data, something that has proven difficult so far.[234]

D. Governance Reforms

As we have explained, one challenge with transmission planning is that incumbent utilities often design planning rules themselves. Addressing these governance issues would go a long way towards rationalizing transmission investment.

1. Restrict Overrepresentation of Large Utilities

Perhaps the most obvious governance reform is to ensure that RTOs and non-RTO transmission planning entities represent their actual constituents and not just the large utilities that provide transmission service in the region. Governance challenges can occur directly, as we described in Section III.D,[235] or they can occur in a more nuanced manner such as when transmission owners control data needed to plan transmission investments. As we explained in Section III, decision-making in RTOs is often a bottom-up process. Lower-level committees create task forces that propose solutions to problems, which are then sent "up" for consideration by senior committees.[236] Lower-level committees may not have final power to pass proposals, but they have an effective veto over what proposals come up for a vote at all. This structure gives large companies outsized influence. In PJM, for example, the Appalachian Power

233. *See, e.g.*, *Loper Bright Enterprises v. Raimondo*, 144 S. Ct. 2244 (2024) (overruling Chevron deference).

234. *See* U.S. Dep't of Energy, Nat'l Transmission Needs Study, *supra* note 205, at v.

235. *See supra* Table 1.

236. Simeone, *supra* note 144, at 3 ("The bulk of the creative process occurs in the lower-level where education takes place and creative solutions are proposed, negotiated, and culled. Proposed solutions must be majority vote-approved up through the chain (if applicable) of lower-level committees then forwarded to the higher-level."); *see also* Kyungjin Yoo & Seth Blumsack, *Can capacity markets be designed by democracy*, 53 J. Reg. Econ. 127, 129 (2018) ("Proposed changes to rules and practices [in PJM] are generally initiated by a stakeholder or a group of stakeholders in one of many lower-level committees. Issues eventually move up to higher-level committees.").

Company[237] has nineteen "affiliate members" represented.[238] These affiliates are either partly or wholly owned subsidiaries of Appalachian Power, and they can vote on a number of important matters. In PJM, affiliates can vote at senior task force and lower-level standing committee meetings, though they cannot vote at senior committee meetings.[239] And Appalachian Power is not an outlier. Duke Energy has six affiliates in PJM; BP Energy has twenty-four; Rolling Hills Generating (owned by LS Power) has thirty.[240]

Allowing affiliates to vote in subcommittees means that larger companies' interests are overrepresented at the lower levels of RTO decision-making. Furthermore, affiliate overrepresentation in PJM occurs disproportionately in the supply-side categories—namely, generator and transmission owners.[241] This creates "an overwhelming supply-side advantage at the lower-level that theoretically guarantees these interests can pass or block any proposal from the lower-level."[242] Load-side interests have a comparatively larger say in the higher levels of PJM's governance, where they can then veto supply-biased proposals. This results in a process that does not fairly represent stakeholders from either category, and it prevents constructive proposals from being considered at all. By contrast, SPP empowers large utilities more directly by allowing equal access to voting regardless of affiliate status.[243]

Some RTOs have gone further in limiting affiliate voting. For example, MISO, ISO-NE, and NYISO all consider affiliate members to be non-voting and offer voting rights only to the parent company.[244] PJM and SPP should adopt similar reforms.

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237. The Appalachian Power Company is wholly owned by American Electric Company, the eighth largest utility in the United States by market cap. *See American Electric Power Co. Inc.*, Wall St. J., https://perma.cc/92TE-3CKJ.

238. *Member List*, PJM (October 4, 2024), https://perma.cc/C4S9-L3VC.

239. *See Operating Agreement*, PJM (2010) §§ 1 (defining "voting member" as "(i) a Member as to which no other Member is an Affiliate or Related Party, or (ii) a Member together with any other Members as to which it is an Affiliate or Related Party"), 8.1.1 (holding that "each Voting Member shall have one vote" for purposes of "voting on the Senior Standing Committees."); *see also* Christina E. Simeone, *supra* note 144, at 3 ("At the higher-level committees, only 'voting members' may cast votes in their designated sectors, and affiliated businesses (i.e. subsidiary companies of the voting member parent company) are excluded from voting.").

240. *Member List*, PJM (Oct. 4, 2024), https://perma.cc/C4S9-L3VC.

241. *See* Simeone, *supra* note 144, at 4 (describing how in PJM, "the introduction of affiliate voting results in 88 % of total lower-level votes being from supply-side sectors").

242. *Id.*

243. This is true in all cases *except* for purposes of electing or removing representatives to the Members Committee and the Corporate Governance Committee. *See Governing Documents Tariff - Bylaws, First Revised Volume No. 4*, SPP (Nov. 8, 2022) §§ 5.1.2(c), 6.6, https://perma.cc/P7M4-C4Q6.

244. *See* Christopher A. Parent et al., *Governance Structure and Practices in the FERC – Jurisdictional ISOs/RTOs* 1-4. 2-2. 2-5. 3-3. 4-2. 5-2. 6-2. 7-2, NESCOE (Feb. 2021), https://perma.cc/Z32T-2H56.

2. *Minimum Participation in Stakeholder Votes*

Stakeholder processes function only where stakeholders actually make their voices heard. To date, RTOs have done too little to ensure robust member participation in voting, and quorum requirements are lenient in all regions. For example, in ISO-NE, a quorum in the Participants Committee "is the lesser of 50% of voting members or five or more voting members from the Participants Committee and three or more voting members from the technical committees."[245] MISO sets quorum requirements by committee,[246] but requires limited participation, especially for subcommittees.[247] NYISO has a complicated process: A quorum in a standing committee is confirmed when at least three sectors are present, with the fewer of five or 50% of members of the sectors present entitled to cast the entirety of the sector's share of the vote. Votes can occur without a quorum present, but the votes are weighted to be a fraction of the proportion of the sector present at the vote.[248] PJM has no quorum requirements except for board votes.[249] This might contribute to low participation rates: In PJM's standing committees, member participation rates hover around 20% and are lowest in the supply sectors.[250]

One explanation for low participation rates is the sheer amount of time and resources it takes to participate in RTO decision-making processes. Task forces and subcommittees meet frequently and produce large volumes of information for members to sift through. Smaller or less-resourced RTO members may not be willing to dedicate staff time to these processes, or they may simply be unaware of what exactly is going on inside the RTO. Larger utilities do not face these same hurdles to participation.

One solution to low participation is to increase quorum requirements. To alleviate the costs that would come with this change, RTOs could scale membership fees by company size, and have larger members partially subsidize participation for smaller market participants. Another solution is to increase staffing of RTOs so that RTO employees would themselves develop RTO rules. These employees would have to be independent of the utilities that are members of RTOs.

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245. *Id.* at 3-7n12.
246. MISO, *Stakeholder Governance Guide* § 3.1.
247. For its Advisory Committee, MISO requires "At least one Advisory Committee voting member or alternate representing at least six of the ten constituent stakeholder groups" to be present. *See* MISO, *Advisory Committee Charter* 2, https://perma.cc/P3T5-HRQQ. For its steering committee, a simple majority of members is a quorum, regardless of sector. MISO, *Steering Committee Charter* 1, https://perma.cc/R4MX-T4E4. Subcommittees have no quorum requirements. *See, e.g.,* MISO, *Resource Adequacy Subcommittee*, https://perma.cc/WAQ4-Y88E.
248. Christopher A. Parent et al., *Governance Structure and Practices in the FERC – Jurisdictional ISOs/RTOs*, *supra* note 1789, at 5-5.
249. *Id.* at 6–13.
250. *See* Simeone, *supra* note 144, at 4.

3. *Reduce Vote Dilution*

ISO-NE, MISO, NY-ISO, PJM, and SPP all decide on final proposals using a by-sector voting process.[251] The choice of sectors is determinative of which votes are overrepresented and which are diluted. In PJM, for example, the two supply-side categories ("Generation Owner" and "Other Supplier") contain 114 and 323 voting members, respectively. In contrast, the three remaining categories contain 75 members *total*.[252] Each sector gets weighed the same in final voting, so that supply-side votes are far more diluted than demand-side votes.

Vote dilution disadvantages renewables providers (who tend to be smaller and more numerous), since they vote in supply-side categories.[253] It also provides an advantage to vertically integrated utilities: Companies that could feasibly fit in more than one sector (e.g., those that have both a supply-side and a load-side interest) may choose which sector to vote in.[254] Hence, a utility that owns both transmission and generation (be it through affiliates or within one entity) can choose to vote in the transmission-owner sector. For PJM, each voting member in that sector controls around 7% of the sector vote. In contrast, members in the "Other Supplier" category each control only 0.3% of the sector vote. By switching sectors, vertically integrated companies are able to increase their voting power by a factor of 23.[255]

Other RTOs have similar issues, although to a lesser degree. For example, ISO-NE (through NEPOOL) divides members into "Supplier," "Generation," "Alternative Resources," "Publicly Owned Entity," "Transmission Owner," and "End User."[256] As of 2024, there were 29 members in the "Generation" sector and 18 members in the "Transmission Owner" sector, as compared to 52 in "Alternative Resources."[257] The latter category contains all renewable suppliers, who again get far less voting power than traditional generation owners or transmission owners.[258]

RTOs should recalibrate voting weights and rights periodically to adapt to the changing composition of their membership. If the current weights are not resulting in sufficient transmission being built (and thereby harming reliability and rates), RTOs are within their rights to resolve that.[259]

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251. Parent et al., *supra* note 178, at Table ES-6.
252. Simeone, *supra* note 144, at 4.
253. *See supra* Section III.C.1 (discussing vote dilution).
254. *See Membership & Sector Selection*, PJM, https://perma.cc/3KN3-S35E ("In order to vote, members must select a single sector that best represents their voting interests, even if they may qualify for more than one sector.").
255. Simeone, *supra* note 144, at 4.
256. *Second Restated NEPOOL Agreement* § 6.2, New England Power Pool (Oct. 1, 2019), https://perma.cc/VU42-D2BP.
257. *Participant Directory*, ISO-NE, https://perma.cc/WU2F-MWPU.
258. *See infra* Appendix for sector composition by RTO.
259. *See also* Simeone, *supra* note 144, at 6 (arguing that "Member and nonmember sectors should fully represent the diversity of RTO/ISO stakeholders. Voting rights and weights should be recalibrated periodically to reflect everchanging stakeholder composition.").

4. *Expand Filing Rights*

Under the FPA, FERC is placed in a mostly passive and reactive role.[260] It faces an asymmetrical burden of proof dependent on whether it is reviewing a filing or offering its own plans: Filings made before FERC must only be "just and reasonable," whereas FERC must show that rates are affirmatively "unjust and unreasonable" in order to fix rates itself.[261] Hence, it is in FERC's interest to have parties with interests aligned with the Commission's file proposals. One way to do this would be to grant filing rights to non-utilities, such as state utility commissions, consumer advocates, or renewable energy producers. This would provide FERC with more plans it can approve under § 205's "just and reasonable" standard, rather than having to rely on the more stringent standard of § 206.

ISO-NE already provides for such a "jump ball provision" in its Participants Agreement. The provision allows NEPOOL's Participants Committee to file a market rule proposal in tandem with the ISO's own proposal if it is supported by at least 60% of the Participants Committee.[262] In such a case, the ISO must describe the alternate market rule proposal in its own filing and explain why the ISO did not adopt it.[263] This description must be sufficiently detailed so as to allow "reasonable review" by FERC. FERC may then, in turn, adopt any or all of either the ISO's market rule or of the alternate rule.[264]

The Commission could require RTOs to add similar provisions to their tariffs covering a variety of groups, ranging from consumer advocates to the states themselves, so that pro-regional transmission parties are given a more direct voice. Doing so would offer FERC the option to choose between multiple proposals rather than seeing only the product of an incumbent-led stakeholder process. In effect, a jump ball provision sidesteps the thorny governance problems that lead to incumbent capture of RTO processes. These provisions offer an alternative solution to the problems that sector-weighted voting and low RTO participation rates by non-incumbents create. At the same time, federal review would ensure that these provisions would not unduly benefit the groups that are given filing rights. FERC is still given the option of going with the RTO's own proposal, and the RTO is able to explain in its filing why it believes its own proposal to be superior. Expanding the pool of parties that are given filing rights simply levels the playing field to a degree, and gives FERC the chance to hear from more non-incumbent voices.

260. *See Advanced Energy Management Alliance v. FERC*, 860 F.3d 656, 662 (D.C. Cir. 2017) (arguing that "when acting on a public utility's rate filing under section 205, the Commission undertakes 'an essentially passive and reactive role' and restricts itself to evaluating the confined proposal.") (internal citations omitted).

261. Federal Power Act, Pub. L. No. 117-58 § 205-206.

262. *Participants Agreement* § 11.1.5, ISO-NE (Sept. 24, 2024), https://perma.cc/WU2F-MWPU.

263. *Id.*

264. *Id.*

5. *Overturn* NRG Power Marketing

Although seemingly a technical reform (even by the standards of a paper on transmission planning!), Congress should overturn the 2017 case *NRG Power Marketing, LLC v. FERC*. There, the D.C. Circuit held that § 205 does not allow FERC to accept a filing subject to modifications if the modifications would "transform the proposal into an entirely new rate of FERC's own making."[265] FERC, the Court held, must play a "passive and reactive role."[266]

NRG both limited FERC's ability to directly address electricity rules and slowed down the rate filing process. As a result of *NRG*, FERC must either meet a higher evidentiary burden of affirmatively establishing that a rate is unjust and unreasonable, reject a filing and waiting for the utility to submit a revised tariff, or simply accept a filing in its entirety. This can result in a prolonged back-and-forth in which filings are repeatedly rejected. It also means that utilities are in the driver's seat when it comes to the design of utility tariffs and electricity market rules, since FERC must now remand filings found to be deficient back to utilities, which then have another opportunity to propose rules.

Congress should overturn *NRG* and clarify that the FPA grants FERC the right to modify rate filings either if the filing entity consents to those changes or if FERC establishes that the modification is just and reasonable. Doing so would empower the Commission to design electricity market rules itself rather than respond to rules submitted by incumbent utilities whose interests do not always align with the public's.

Conclusion

Although federal law is designed to encourage utilities to engage in forward-looking transmission planning that simultaneously considers the many benefits of new projects, most transmission investment today is made outside the regional planning process and in response to one-off needs. This is largely because utilities take advantage of exemptions to the regional process to avoid competition, protect their own financial interests, and minimize regulatory scrutiny. In our view, modest reforms to existing transmission planning processes are unlikely to lead to the kind of investment that is needed to support ambitious decarbonization goals or meaningfully improve grid reliability. As a result, we have proposed ambitious reforms that would allow the federal government to play a more active role in planning, paying for, and permitting new lines.

265. NRG Power Marketing, LLC. v. FERC, 862 F.3d 108, 110 (D.C. Cir. 2017).
266. *Id.* at 114 (citing Advanced Energy Management Alliance, 860 F.3d at 662).

State	kV Floor	Statutory Language	Governing Statute
Alabama		No plant, property or facility for the production, transmission, delivery or furnishing of gas, electricity, water or steam shall be constructed, *except ordinary extensions of existing systems in the usual course of business*, until written application is first made to the commission for the issuance of a certificate of convenience and necessity.	Ala. Code § 37-4-28
Alaska	69	A public utility . . . may not construct a large energy facility unless the commission determines that the facility is necessary . . . . [A] "large energy facility" means . . . a high-voltage, above-ground transmission line that (A) has a capacity of 69 kilovolts or more; and (B) is longer than 10 miles.	Alaska Stat. § 42.05.785(a); Alaska Stat. § 42.05.785(e)(2-3).
Arizona	115	Every utility planning to construct a . . . transmission line [in] this state shall first file with the commission an application for a certificate of environmental compatibility. "Transmission line" means five or more new . . . designed for the transmission of electric energy at nominal voltages of one hundred fifteen thousand volts or more.	Az. Rev. Stat. § 40-360.03; Az. Rev. Stat. § 40-360(10).

Arkansas	100 (lines longer than 10 miles); 170 (between 1 and 10 miles in length).	Except for persons exempted as provided in subsection (c) of this section and § 23-18-504(a) and § 23-18-508, a person shall not begin construction of a major utility facility in the state without first obtaining a certificate of environmental compatibility and public need. The replacement or expansion of an existing transmission facility with a similar facility in substantially the same location or the rebuilding, upgrading, modernizing, or reconstruction for the purposes of increasing capacity shall not constitute construction of a major utility facility if no increase in width of right-of-way is required. This subchapter does not require a certificate of environmental compatibility and public need [for] an electric transmission line and associated facilities including substations of a design voltage of one hundred kilovolts (100 kV) or more to be constructed or operated by a municipal electric utility system that is located within the territorial limits of the municipal electric utility system. For the sole purpose of requiring an environmental impact statement under this subchapter, an electric transmission line and associated facilities including substations of: • (i) A design voltage of one hundred kilovolts (100 kV) or more and extending a distance of more than ten (10) miles; or • (ii) A design voltage of one hundred seventy kilovolts (170 kV) or more and extending a distance of more than one (1) mile.	Ark. Code Ann. § 23-18-510(a)(1-2); Ark. Code Ann. § 23-18-503(6)(B).

California	200	[An] electrical corporation [shall not begin the construction of a line] without having first obtained from the commission a certificate [of public convenience and necessity]. The extension, expansion, upgrade, or other modification of an existing electrical transmission facility, including transmission lines and substations, does not require a certificate [of public convenience and necessity]. [A] transmission line is a line designed to operate at or above 200 kilovolts.	Cal. Pub. Util. Code § 1001(a-b); Cal. Pub. Util. Comm. General Order No. 131-D § 1.
Colorado	69	A public utility shall not begin the construction of a new facility, plant, or system or the extension of its facility, plant, or system without first obtaining from the commission a certificate [of public convenience and necessity]. [This section does not] require a corporation to secure a certificate for . . . I. An extension within any city and county, city, or town within which it has already lawfully commenced operations; II. An extension into territory, either within or outside of a city and county, city, or town, contiguous to its facility, line, plant, or system and not already served by a public utility providing the same commodity or service; III. An extension within or to territory already served by the corporation, as is necessary in the ordinary course of its business As used in this section . . . major electrical or natural gas facilities [includes] transmission lines operated at a nominal voltage of sixty-nine thousand volts or above	Col. Rev. Stat. § 40-5-101(1)(a); Col. Rev. Stat. § 29-20-108

Connecticut	69	No [public utility] shall acquire real property in contemplation of a possible future transmission facility, other than a facility for which the council has issued a certificate [of public necessity and convenience], except as provided in regulations adopted by the council. “Facility” means: (1) An electric transmission line of a design capacity of sixty-nine kilovolts or more . . .	Conn. Gen. Stat. 6 16-50z(a); Conn. Gen. Stat. 6 16-50i(a)
Delaware	34.5	[N]o person or entity shall begin the business of an electric transmission utility providing transmission facilities, as defined in § 1001(26) of this title, without having first obtained from the Commission a certificate [of public necessity and convenience]. This section shall not be construed to require any public utility to secure such a certificate for any construction, modifications, upgrades or extensions within the perimeter of any territory already served by it. “Transmission facilities” means electric facilities located in Delaware . . . that operate at voltages above 34,500 volts.	26 Del. Code § 203E(a); 26 Del. Code § 203A(a)(3); 26 Del. Code § 1001(26).
Florida	230	“Transmission line” or “electric transmission line” means structures, maintenance and access roads, and all other facilities . . . constructed, operated, or maintained for the purpose of conveying electric power . . . at 230 kilovolts or more. [C]onstruction of a transmission line may not be undertaken without first obtaining certification [of public convenience and necessity], but this act does not apply to a) Transmission lines for which development approval has been obtained under chapter 380 b) [ ] c) [ ] d) [T]ransmission lines that are less than 15 miles in length or are located in a single county within the state.	403 Florida Stat. § 524.

Georgia		No requirement to obtain a certificate of public convenience and necessity for transmission lines.	Ga. Code § 22-3-160.1
Hawai'i	46	No public utility, as defined in section 269-1, shall commence its business without first having obtained from the commission a certificate of public convenience and necessity. Whenever a public utility plans to place, construct, erect, or otherwise build a new 46 kilovolt or greater high-voltage electric transmission system above the surface of the ground through any residential area, the public utilities commission shall conduct a public hearing prior to its issuance of approval thereof.	HI Rev. Stat. § 269-7.5(a); HI Rev. Stat. § 269-27.5
Idaho		[No] electrical corporation . . . shall henceforth begin the construction of a street railroad, or of a line, plant, or system or of any extension of such street railroad, or line, plant, or system, without having first obtained from the commission a certificate [of public convenience and necessity]. The term "electric plant" [includes all] property for containing, holding or carrying conductors used or to be used for the transmission of electricity for light, heat or power.	Id. Code § 61-526;
Illinois		No exemptions or voltage floors.	220 Il. Stat. § 5/8-406.

Indiana		Except as provided in section 7 of this chapter, a public utility may not begin the construction, purchase, or lease of any steam, water, or other facility for the generation of electricity to be directly or indirectly used for the furnishing of public utility service, even though the facility is for furnishing the service already being rendered, without first obtaining from the commission a certificate that public convenience and necessity requires, or will require, such construction, purchase, or lease.	Ind. Code § 8-1-8.5-2;
Iowa	69	A person shall not construct, erect, maintain, or operate a transmission line, wire, or cable that is capable of operating at an electric voltage of sixty-nine kilovolts or more along, over, or across any public highway or grounds outside of cities for the transmission, distribution, or sale of electric current without first procuring from the utilities board a franchise . . . If the transmission line, wire, or cable is capable of operating only at an electric voltage of less than sixty-nine kilovolts, no franchise is required.	Iowa Code § 478.1
Kansas	230	No electric utility may begin site preparation for or construction of an electric transmission line, or exercise the right of eminent domain to acquire any interest in land in connection with the site preparation for a construction of any such line without first acquiring a siting permit from the commission. “Electric transmission lines” means any line or extension of a line which is at least five (5) miles in length and which is used for the bulk transfer of two hundred thirty (230) kilovolts or more of electricity;	66 Ks. Stat. 178(a); 66 Ks. Stat. 177(b)

Kentucky	138 (if an ordinary extension of an existing system).	For the purposes of this section, construction of any electric transmission line of one hundred thirty-eight (138) kilovolts or more and of more than five thousand two hundred eighty (5,280) feet in length shall not be considered an ordinary extension of an existing system in the usual course of business and shall require a certificate of public convenience and necessity. However, ordinary extensions of existing systems in the usual course of business not requiring such a certificate shall include: a) The replacement or upgrading of any existing electric transmission line; or b) The relocation of any existing electric transmission line to accommodate construction or expansion of a roadway or other transportation infrastructure; or c) (c) An electric transmission line that is constructed solely to serve a single customer and that will pass over no property other than that owned by the customer to be served.	Ky. Rev. Stat. § 278.020(2).
Louisiana		No public utility shall begin the construction of any new plant, equipment, property, or facility, which is not in substitution of an existing plan, property, equipment, or facility, nor shall it make any extension or addition to any existing plant, property, equipment, or facility which will cost over two per cent of the rate-making value of the property at the time the extension or addition is made, nor shall any indeterminate permit or franchise be granted, unless and until the governing authority of the city certifies that public convenience and necessity require the same.	La. Rev. Stat. 33:4406

Maine	69	A person may not construct any transmission project or subtransmission project without approval from the commission. For the purposes of this section, "transmission project" means any proposed new or upgraded transmission substation infrastructure that is capable of operating at 69 kilovolts or more.	35-A Me. Rev. Stat. § 3132-A.
Maryland	69	Unless a certificate of public convenience and necessity for the construction is first obtained from the Commission, an electric company may not begin construction of an overhead transmission line that is designed to carry a voltage in excess of 69,000 volts or exercise a right of condemnation with the construction.	Md. P.U.C. § 7-207(b)(3)
Massachusetts	69	[Defining transmission as] the delivery of power over lines that operate at a voltage level typically equal to or greater than 69,000 volts from generating facilities across interconnected high-voltage lines to where it enters a distribution system. The department [of public utilities], after notice and a public hearing in one or more of the towns affected, may determine that [a transmission] line is necessary for the purpose alleged, and will serve the public convenience and is consistent with the public interest.	164 Mass. Gen. Laws § 1; 164 Mass. Gen. Laws § 72;

Michigan	340	Except as otherwise provided in section 9, a certificate of public convenience and necessity under this act is not required for constructing a new transmission line other than a major transmission line or for reconstructing, repairing, replacing, or improving an existing transmission line, including the addition of circuits to an existing transmission line A [utility] may file an application with the commission for a certificate for a proposed transmission line other than a major transmission line . . . that certificate shall take precedence over a conflicting local ordinance, law, rule, regulation, policy, or practice that prohibits or regulates the location or construction of a transmission line for which the commission has issued a certificate. "Transmission line" means all structures, equipment, and real property necessary to transfer electricity at system bulk supply voltage of 100 kilovolts or more . . . "Major transmission line" means a transmission line of 5 miles or more in length wholly or partially owned by an electric utility, affiliated transmission company, or independent transmission company through which electricity is transferred at system bulk supply voltage of 345 kilovolts or more.	Mich. Comp. Laws § 460.560; Mich. Comp. Laws § 460.565; Mich. Comp. Laws §§ 460.569-70;

Minnesota	300 if more than 1 mile but less than 10 miles, 100 if longer than 10 miles.	No large energy facility shall be sited or constructed in Minnesota without the issuance of a certificate of need, [but this does not apply to] the upgrade to a higher voltage of an existing transmission line that serves the demand of a single customer that primarily uses existing rights-of-way; a high-voltage transmission line of one mile or less required to connect a new or upgraded substation to an existing, new, or upgraded high-voltage transmission line; transmission lines that directly interconnect large wind energy conversion systems, solar energy generating systems, or energy storage systems to the transmission system; relocation of an existing high-voltage transmission line to new right-of-way, provided that any new structures that are installed are not designed for and capable of operation at higher voltage. “Large energy facility” means: . . . any high-voltage transmission line with a capacity of 300 kilovolts or more and greater than one mile in length in Minnesota; any high-voltage transmission line with a capacity of 100 kilovolts or more with more than ten miles of its length in Minnesota.	Minn. Stat. 216B.24; Minn. Stat. 216B.2421
Mississippi		No exceptions.	Miss. Code § 77-3-11(2).
Missouri		No exceptions.	Mo. Code Regs. tit. 20 § 4240-20.045(2)

Montana	69 or 230 if less than ten miles in length	"Facility" means: each electric transmission line and associated facilities of a design capacity of more than 69 kilovolts, except that the term: • does not include an electric transmission line and associated facilities of a design capacity of 230 kilovolts or less and 10 miles or less in length; • does not include an upgrade to an existing transmission line of a design capacity of 50 kilovolts or more to increase that line's capacity, including construction outside the existing easement or right-of-way. [A] person may not commence to construct a facility in the state without first applying for and obtaining a certificate of compliance issued with respect to the facility by the department.	Mt. Ann. Code § 75-20-104(10); Mt. Ann. Code § 75-20-201
Nebraska	No exemptions	Before any electric generation facilities or any transmission lines or related facilities carrying more than seven hundred volts are constructed or acquired by any supplier, an application, filed with the board and containing such information as the board shall prescribe, shall be approved by the board, except that such approval shall not be required (a) for the construction or acquisition of a transmission line extension or related facilities within a supplier's own service area or for the construction or acquisition of a line not exceeding one-half mile outside its own service area when all owners of electric lines located within one-half mile of the extension consent thereto in writing and such consents are filed with the board . . . (c) for acquisition of transmission lines or related facilities, within the state, carrying one hundred fifteen thousand volts or less, if the current owner of the transmission lines or related facilities notifies the board of the lines or facilities involved in the transaction and the parties to the transaction.	Neb. Rev. Stat. § 70-1012(1)

Nevada	200	"Utility facility" means . . . Electric transmission lines and transmission substations that: are designed to operate at 200 kilovolts or more; are not required by local ordinance to be placed underground; and are constructed outside any incorporated city. A person, other than a local government, shall not commence to construct a utility facility in the State without first having obtained a permit therefor from the Commission.	Nev. Rev. Stat. § 704.860; Nev. Rev. Stat. § 704.864
New Hampshire	100 if over a new route; 200 if over an existing route.	No person shall commence to construct any energy facility within the state unless it has obtained a certificate pursuant to this chapter. "Energy facility" means: (c) An electric transmission line of design rating of 100 kilovolts or more, . . . over a route not already occupied by a transmission line or lines. (d) An electric transmission line of a design rating in excess of 100 kilovolts that is in excess of 10 miles in length, over a route not already occupied by a transmission line. (e) A new electric transmission line of design rating in excess of 200 kilovolts.	N.H. Rev. Stats. § 162-H:5; N.H. Rev. Stat. § 162-H:2
New Jersey	No exemptions		
New Mexico	No exemptions	No public utility shall begin the construction or operation of any public utility plant or system or of any extension of any plant or system without first obtaining from the commission a certificate that public convenience and necessity require or will require such construction or operation.	N.M. Stats § 62-9-1.

New York	100 if longer than ten miles, 125 if longer than a mile.	No person shall, after July first, nineteen hundred seventy, commence the preparation of the site for the construction of a major utility transmission facility in the state without having first obtained a certificate of environmental compatibility and public need. “Major utility transmission facility” means: (a) an electric transmission line of a design capacity of one hundred twenty-five kilovolts or more extending a distance of one mile or more, or of one hundred kilovolts or more and less than one hundred twenty-five kilovolts, extending a distance of ten miles or more.	N.Y. Pub. Serv. Laws § 120-121.
	161	No public utility or any other person may begin to construct a new transmission line without first obtaining from the Commission a certificate of environmental compatibility and public convenience and necessity. The term “transmission line” means an electric line designed with a capacity of at least 161 kilovolts.	N.C. Gen. Stats. § 62-100; N.C. Gen. Stats. § 62-101
North Dakota	115	An electric public utility may not begin construction or operation of a public utility plant or system, or of an extension of a plant or system without first obtaining from the commission a certificate that public convenience and necessity require or will require the construction and operation. “Electric transmission line” means facilities for conducting electric energy at a design voltage of one hundred fifteen kilovolts or greater phase to phase and more than one mile [1.61 kilometers] long.	N.D. Cent. Code § 49-03-01; N.D. Cent. Code § 49-03-01.5

Ohio	100	No person shall commence to construct a major utility facility in this state without first having obtained a certificate for the facility. The replacement of an existing facility with a like facility. . . shall not constitute construction of a major utility facility. Such replacement of a like facility is not exempt from any other requirements of state or local laws or regulations. Major utility facility means . . . An electric transmission line and associated facilities of a design capacity of one hundred kilovolts or more.	Ohio Rev. Code § 4906.04; Ohio Rev. Code § 4906.01
Oklahoma	No exemption		
Oregon	No exemption		
Pennsylvania	100	Upon the application of a public utility for authorization to locate and construct a HV transmission line or any portion thereof, upon approval of the application by the Commission first had and obtained, and upon compliance with existing laws, it shall be lawful for a public utility to commence construction of the HV transmission line or portion thereof. [Defines HV transmission line or HV line [as] an overhead electric supply line with a design voltage greater than 100,000 volts.	52 Pa. Code § 57.71; 52 Pa. Code § 57.1
Rhode Island	69	"Major energy facility" [is defined as] . . . transmission lines of sixty-nine (69) Kv or over. No person shall site, construct, or alter a major energy facility within the state without first obtaining a license from the siting board pursuant to this chapter.	R.I. Gen. Laws § 42-98-3; R.I. Gen. Laws § 42-98-4

South Carolina	125	No person shall commence to construct a major utility facility without first having obtained a certificate issued with respect to such facility by the Commission. The term "major utility facility" means . . . an electric transmission line and associated facilities of a designed operating voltage of one hundred twenty-five kilovolts or more; provided, however, that the words "major utility facility" shall not include electric distribution lines and associated facilities.	S.C. Ann. Stat. § 58-33-110; S.C. Ann. Stat. § 58-33-20
South Dakota	115	For the purposes of this chapter, a transmission facility is . . . An electric transmission line and associated facilities with a design of more than one hundred fifteen kilovolts. No utility may begin construction of a facility in the state on or after July 1, 1979, without first having obtained a permit issued with respect to such facility by the Public Utilities Commission pursuant to this chapter.	S.D. Cod. Laws § 49-41B-2.1; S.D. Cod. Laws § 49-41B-4
Tennessee	No exemptions		
Texas	No exemptions		
Utah	No exemptions		
Vermont	No exemptions		
Virginia	No exemptions		

Washington	115	No construction or reconstruction of . . . energy facilities may be undertaken, except as otherwise provided in this chapter, without first obtaining certification in the manner provided in this chapter. "Associated facilities" means storage, transmission, handling, or other related and supporting facilities connecting an energy plant with the existing energy supply, processing, or distribution system, including, but not limited to, communications, controls, mobilizing or maintenance equipment, instrumentation, and other types of ancillary transmission equipment, off-line storage or venting required for efficient operation or safety of the transmission system and overhead, and surface or subsurface lines of physical access for the inspection, maintenance, and safe operations of the transmission facility and new transmission lines constructed to operate at nominal voltages of at least 115,000 volts	Wash. Rev. Code § 80.50.010; Wash. Rev. Code § 80.50.060
West Virginia	200	No public utility, person or corporation may begin construction of a high-voltage transmission line of two hundred thousand volts or over, which line is not an ordinary extension of an existing system in the usual course of business as defined by the Public Service Commission, unless and until it or he or she has obtained from the Public Service Commission a certificate of public convenience and necessity approving the construction and proposed location of the transmission line.	W. Va. Code § 24-2-11a
Wisconsin	No exemptions		Wi. Admin. Code PSC
Wyoming	No exemptions		