Electricity Transmission: What Is the Role of the Federal Government?

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Electricity Transmission: What Is the Role of the Federal Government?

SUMMARY

Electricity transmission is central to the operation of the electricity system, and so has been of longstanding interest to Congress. Interest in electricity transmission has increased since the enactment of the Infrastructure Investment and Jobs Act (IIJA; P.L. 117-58) in 2021 and P.L. 117-169 (commonly known as the Inflation Reduction Act or IRA) in 2022. The Federal Energy Regulatory Commission (FERC) and other agencies have proposed changes to their electricity transmission policies. Any changes to federal electricity transmission policies could potentially have lasting impact on the U.S. electricity system given the long-lived nature (typically 50 years or more) of electricity transmission facilities.

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The Federal Power Act (FPA), the main governing statute for the electricity system, leaves decisions regarding the physical siting of most transmission facilities to the states. The Energy Policy Act of 2005 (P.L. 109-58) carved out a more significant federal role in certain transmission siting decisions, establishing what is commonly called a "backstop" siting authority for FERC. It authorized FERC to issue permits for the construction or modification of transmission facilities in certain circumstances in areas designated by the Secretary of Energy as "National Interest Electric Transmission Corridors." Two decisions in federal appellate courts in 2009 and 2011 undid efforts by FERC and the Department of Energy (DOE) to use the 2005 backstop siting authority, and the agencies largely abandoned their efforts. The IIJA amended Section 216 of the FPA to address, among other things, the issues identified in these decisions. In 2023, DOE and FERC proposed new rules to implement their amended authority. No corridors have been designated to date. Legislative proposals in the 118th Congress would make additional modifications to transmission siting authority, with some giving FERC primary siting authority for certain kinds of transmission facilities.

For transmission facilities on federal lands, the relevant federal agency managing that land generally must approve the construction and operation of the facility. The agency's review of any such requests must account for the broader land management plan for the area, environmental impacts, required cross-agency consultations, and other limitations and requirements placed on federal agencies by federal statutes

FERC transmission policies apply to most electricity transmission facilities (exceptions include facilities located in Alaska, Hawaii, or much of Texas). FERC requires transmission owners to conduct transmission planning, with a goal of promoting increased coordination in the development of transmission facilities that cross multiple transmission owners' service territories. These kinds of facilities, such as multi-state transmission lines, may be more efficient and cost effective in some cases compared to facilities that primarily serve a single transmission owner (and its customers).

As part of their planning process, transmission owners must decide how to allocate to customers the costs of constructing and operating transmission facilities. Cost allocation generally relies upon the *cost causation* principle of electricity ratemaking, sometimes expressed as *beneficiary pays*. This principle requires that the beneficiaries of an electricity asset cover its costs and, conversely, that electricity consumers that do not receive benefits do not cover any costs. Cost allocation can be a contentious issue because it directly affects consumers' rates. It can also affect siting decisions because state regulators may be more willing to site transmission lines if they believe the costs of the line have been allocated fairly (and vice versa).

In 2022, FERC proposed modifying its transmission planning and cost allocation policies with a goal of promoting increased investment in large, multi-state transmission lines and other facilities that may be more efficient and cost effective. Legislative proposals in the 118th Congress have also addressed transmission planning and cost allocation. Proposals include requirements for increased regional and interregional planning, as well as consideration of a broad set of transmission benefits for purposes of cost allocation.

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Introduction

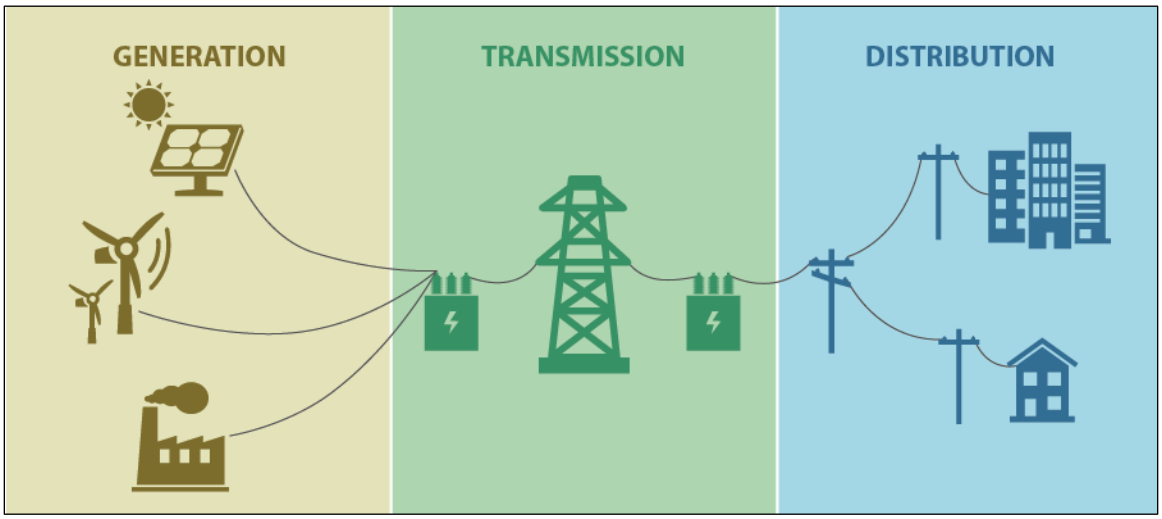
As the country's electricity needs expand and potential energy sources diversify, many observers believe America requires more and higher-capacity electricity transmission lines, often spanning two or more states. Construction of such lines is influenced by myriad factors, including state-level decisions, federal policy, and electricity industry developments. Recently enacted legislation has provided funding for infrastructure projects and attempted to address perceived delays in the federal permitting process. These developments have increased attention on the potential federal role in promoting expanded transmission capacity. This report discusses the role of the federal government in electricity transmission, with a focus on key issues in the 118th Congress.

Background

What Is the Electric Transmission System?[1]

Electric transmission systems are the lines, towers, transformers, and other equipment connecting power generation facilities to distribution systems that make final delivery of electricity to most customers (**Figure 1**).

Figure 1. Electric Power Sector System Schematic



Source: CRS, adapted from U.S.-Canada Power System Outage Task Force, *Final Report on the August 14, 2003, Blackout in the United States and Canada: Causes and Recommendations*, April 2004, p. 5.

Note: Not all types of components in each system are shown.

The U.S. transmission system includes hundreds of thousands of miles of conductors (i.e., power lines) that carry electricity at relatively high voltages. Transmission line voltages range from 230 thousand volts (kV) to 765 kV, though lower voltages can be used as well.[2] The higher the voltage, the more power can move through the line. Approximately 98% of the U.S. transmission system uses alternating current (AC) power, in which the direction of electrical charge changes 60

[1] For additional background on electricity transmission, see CRS In Focus IF12253, *Introduction to Electricity Transmission*, by Ashley J. Lawson, and CRS Report R47521, *Electricity: Overview and Issues for Congress*, by Ashley J. Lawson.

[2] U.S. Department of Energy (DOE), *United States Electricity Industry Primer*, July 2015, p. 14.

times per second.[3] The remainder uses direct current (DC), in which the direction of charge does not change. AC power can be converted relatively easily and cheaply between high and low voltages, making it more suitable for delivering it to customers that use low voltage AC (e.g., 120 V for most households). DC lines require expensive conversion stations, but they can be more efficient over very long distances and better suited for specialized applications, such as undersea cables.

The transmission system also includes thousands of transformers that change voltage levels, "stepping up" or "stepping down" voltages to higher or lower levels, respectively. Transformers also provide electric stability to the grid. High-voltage transformers vary in size (measured in input/output voltage or power levels) and typically are custom-built for specific locations in the transmission system. This report generally uses the term *facilities* to refer to transmission lines, transformers, and other related equipment.

How is the Electric Transmission System Regulated?

The Federal Power Act (FPA), enacted in 1920 as the Federal Water Power Act and amended to include interstate electricity transmission in 1935, granted the Federal Power Commission (the predecessor to the Federal Energy Regulatory Commission (FERC)) jurisdiction over wholesale electric power transactions and the interstate transmission of electric power.[4] Prior to passage of the FPA, electricity transmission services were regulated piecemeal by state and local government. Under the FPA, FERC regulates the rates companies charge for interstate transmission services and the planning processes used to develop most interstate transmission facilities (discussed below). Title II of the Federal Power Act generally limits FERC's authority to wholesale sales and interstate transmission, so some areas of the country are not subject to FERC's jurisdiction over transmission pricing under the act. Examples include Alaska, Hawaii, and much of Texas.[5] The states, for the most part, retain jurisdiction over the siting of generation and transmission facilities as well as the pricing of most retail electric power transactions.

Most transmission facilities are owned and operated by private companies, though some public entities—including federal entities—also own and operate transmission facilities. Federal entities authorized to own and operate transmission facilities include the Tennessee Valley Authority (TVA),[6] the Bonneville Power Administration (BPA),[7] the Southwestern Power Administration (SWPA),[8] and the Western Area Power Administration (WAPA).[9] Each of these federal entities is authorized by Congress for specific purposes, and has unique statutory obligations regarding transmission planning and financing. In general, most federal transmission policies overseen by FERC do not apply to these federal entities, though they may voluntarily opt in so long as they

[3] U.S. Government Accountability Office, *Transmission Lines: Issues Associated with High-Voltage Direct-Current Transmission Lines Along Transportation Rights of Way*, February 1, 2008, p. 8.

[4] 16 U.S.C. §824(b).

[5] Much of Texas is served by the Electric Reliability Council of Texas (ERCOT), which operates an independent transmission grid that is not electrically synchronized with neighboring states. As a result, electricity is not generally exchanged between ERCOT and neighboring states, so the power sales and transmission activity are not subject to much of FERC's electricity sector jurisdiction. Certain specific electricity transactions within ERCOT may fall under FERC's authority, pursuant to other sections of the Federal Power Act.

[6] 16 U.S.C. §831k.

[7] 16 U.S.C. §838b.

[8] 16 U.S.C. §825s.

[9] 42 U.S.C. §7152(a)(1)(D).

operate within the constraints of their authorizing statutes. In many cases, these federal entities have authority to site their own transmission facilities.

Electricity Transmission Siting Authority

For most of the 20th century, transmission facilities were generally constructed and operated by "vertically integrated" electric utilities; that is, state-authorized and state-regulated monopolies that owned power plants, transmission facilities, and local distribution systems, and which also sold electricity to retail customers. While transmission facilities were almost exclusively intrastate in nature at first, the transmission system expanded rapidly to include interstate lines.

As the mostly local electric power system began to interconnect into larger regional grids, interconnections were motivated by the reliability benefits of connecting a utility to its neighbors, opportunities for power sales, and joint ownership of increasingly large and expensive power plants. The development of higher-voltage transmission lines—which made it possible to transmit electricity long distances with relatively small losses—also spurred interconnection.

Throughout this expansion, the states continued to be the sole authority for most decisions about where to site electric power transmission facilities. As noted above, federal entities such as TVA generally are able to site the transmission lines they operate independent of state authority. In addition, publicly owned utilities such as rural electric cooperatives and municipal utilities generally have siting authority within their own territories. And while the vast majority of transmission facilities are constructed by investor-owned utilities under state jurisdiction, in the 21st century, interest has arisen in giving the federal government a role in siting transmission infrastructure.

The Energy Policy Act of 2005

The Energy Policy Act of 2005 (EPACT05; P.L. 109-58) established a more significant federal role in certain transmission siting decisions. Section 1221 of EPACT05 enacted a new Section 216 of the FPA, establishing what is commonly called a "backstop" siting authority for FERC. It authorized FERC to issue permits for the construction or modification of transmission facilities in certain circumstances in areas designated by the Secretary of Energy as "National Interest Electric Transmission Corridors" (NIETCs).[10] EPACT05 directed the Secretary of Energy to "conduct a study of electric transmission and congestion" and subsequently "issue a report, based on the study, which may designate any geographic area experiencing electric energy transmission capacity constraints or congestion that adversely affects consumers as a national interest electric transmission corridor."[11] According to EPACT05, the variables to be considered in establishing NIETCs include:

- whether the economic vitality and development of the corridor, or the end markets served by the corridor, may be constrained by lack of adequate or reasonably priced electricity;
- whether economic growth in the corridor warrants a diversification of energy supply;
- whether the energy independence of the United States would be served by the designation;

[10] 16 U.S.C. §824p.

[11] Ibid.

- whether the designation would be in the interest of national energy policy; and
- whether the designation would enhance national defense and homeland security.[12]

After passage of EPACT05, both FERC and the U.S. Department of Energy (DOE) initiated administrative proceedings as directed by Section 1221. FERC issued a Final Rule in December 2006,[13] while DOE conducted proceedings to determine and designate NIETCs in 2006 and 2007.[14] However, these administrative actions were undone by legal challenges.

Piedmont Environmental Council v. FERC

In a 2009 decision, *Piedmont Environmental Council v. FERC*,[15] the U.S. Court of Appeals for the Fourth Circuit interpreted the scope and meaning of Section 1221 of EPACT05 and held that FERC had exceeded its statutory authority. Section 1221 provided that FERC could exercise its backstop electricity transmission siting authority if "a State commission or other entity that has authority to approve the siting of the facilities has … withheld approval for more than 1 year."[16] In its final rule, FERC interpreted this authority to be applicable not only in cases in which the state agency has failed to act but also cases in which the state agency has denied or rejected a request for the required approval.[17]

The court disagreed, finding that the plain meaning of the statute indicated that Congress intended to make backstop federal siting authority available only where the state had not made any decision on proposed facilities, and not where the state had decided to deny the requested authorization.[18] The court interpreted the phrase "withheld approval for more than one year" to require continuous withholding. It held that a denial did not fit this description, as it is a final decision that "stops the running of time during which approval was withheld on a pending application."[19] This determination limited the reach of FERC's electricity transmission siting authority, as states retained full authority to reject any proposed facilities within their borders.

California Wilderness Coalition v. Department of Energy

Two years after *Piedmont*, a second appellate decision dealt another blow to the widespread implementation of backstop federal transmission siting authority. In *California Wilderness Coalition v. Department of Energy*,[20] the U.S. Court of Appeals for the Ninth Circuit held that DOE failed to consult with the state, as required by the statute, before it designated the Mid-Atlantic and Southwest NIETCs.[21] Section 1221(a)(1) directed the Secretary of Energy to perform a transmission congestion study to inform NIETC designations "in consultation with affected states."[22] DOE argued that it satisfied this statutory requirement by reaching out to the affected

[12] Ibid.

[13] "Regulations for Filing Applications for Permits to Site Interstate Electric Transmission Facilities (Order No. 689)," 71 *Federal Register* 69440, December 1, 2006.

[14] "National Electric Transmission Congestion Report," 72 *Federal Register* 56992, October 5, 2007.

[15] 558 F.3d 304 (4th Cir. 2009).

[16] EPACT05 (P.L. 109-58) at §1221.

[17] Order No. 689, 71 *Federal Register* 69444-69445.

[18] Piedmont, 558 F.3d at 313-315.

[19] Ibid. at 313.

[20] 621 F.3d 1072 (9th Cir. 2011).

[21] Ibid. at 1107.

[22] 16 U.S.C. §824p(a)(1).

states "through meetings with the National Association of Regulatory Utility Commissioners ('NARUC') and through other meetings and correspondence with individual State entities"[23] and by inviting the states to submit comments at various points during the process.[24] DOE also argued that "there are practical difficulties in conducting the level of consultation that some may prefer in the context of a study of this magnitude" and that it "is difficult to know which States are 'affected' until the conclusions of the congestion study are known."[25] The court rejected these efforts as insufficient to satisfy the statutory requirement for "consultation"[26] and focused in particular on DOE's failure to share relevant modeling data with the affected states.[27] The court vacated both the DOE Congestion Study and the NIETCs proposed as a result of the study and remanded them to DOE.[28]

After these decisions in federal appellate courts both limited FERC's transmission siting authority within NIETCs and required more robust consultation in DOE's efforts to establish NIETCs, federal backstop transmission authority was largely abandoned by the agencies and the industry. However, recent legislative efforts have revived interest and potentially allow for a more extensive federal role.

The Infrastructure Investment and Jobs Act

In 2021, Congress amended FERC's backstop siting authority in the Infrastructure Investment and Jobs Act (IIJA; P.L. 117-58) to address, among other things, the issues identified by the court of appeals decisions. The IIJA amended Section 216 of the FPA to explicitly authorize FERC to exercise its backstop transmission siting authority not only when a state authority has not made a determination regarding a proposed project or has placed unreasonable conditions on its authorization, but also when the state has denied the proposal. This provision effectively codified the expanded backstop electricity siting authority that FERC had asserted in its final rule in 2006,[29] which had been struck down by the Fourth Circuit in *Piedmont*.[30]

The IIJA amendments to Section 216 of the FPA spurred both FERC and DOE to administrative action. DOE renewed its efforts to designate NIETCs, proposing to "designate NIETCs that are 'route-specific,' meaning they encompass narrow areas that are under consideration for the location of specific potential project(s), and which are sufficient for the construction, maintenance, and safe operation thereof in accordance with any applicable regulatory requirements."[31]

FERC proposed a new set of regulations to implement its expanded backstop siting jurisdiction under the IIJA.[32] The new regulations would also allow for concurrent state and federal review of

[23] Calif. Wilderness Coalition, 621 F.3d at 1081.

[24] Ibid. at 1081-1082.

[25] Ibid.

[26] Ibid. at 1086-1090.

[27] Ibid. at 1089-1090.

[28] Ibid. at 1106.

[29] Order No. 689, 71 *Federal Register* 69440, December 1, 2006.

[30] 558 F.3d 304 (4th Cir. 2009).

[31] "Notice of Intent and Request for Information: Designation of National Interest Electric Transmission Corridors," 88 *Federal Register* 30956, 30957, May 15, 2023.

[32] "Applications for Permits to Site Interstate Electric Transmission Facilities," 88 *Federal Register* 2770, January 17, 2023.

proposed transmission projects,[33] would require applicants to demonstrate good faith efforts to acquire the relevant property interests prior to being granted eminent domain authority,[34] and would direct the agency to consider environmental justice in these permitting decisions, among other proposed changes.[35] The comment period for this proposed rule ended on May 17, 2023. FERC does not appear to have taken any further action on its proposal as of the date of this report.

Transmission Siting Proposals in the 118th Congress

Permitting reform has been a key topic of debate in the 118th Congress, including some proposals to modify FERC's backstop siting authority. One proposal would remove the requirement that DOE identify NIETCs, leaving FERC as the sole federal agency implementing the backstop siting authority. This proposal is included in S. 1399, the Building American Energy Security Act of 2023. Another proposal would give FERC siting authority over a broader range of proposed facilities, diminishing the state role in transmission siting. This proposal is included in, for example, a discussion draft of the Promoting Efficient and Engaged Reviews Act (PEER Act).[36]

Additional information is in CRS Report R47627, *Electricity Transmission Permitting Reform Proposals*, by Ashley J. Lawson.

Transmission Siting on Federal Land

Electric transmission facilities, particularly those needed to enhance grid reliability, often cover many miles and cross multiple jurisdictions, including federal, state, tribal, and private lands. To construct and operate electric transmission facilities on or through federal lands, project developers generally must secure authorizations from one or more federal agencies. This includes authorizations from the federal agency responsible for administering the land on which the proposed project is located or crosses.

Four federal land management agencies (FLMAs) administer the vast majority of land owned by the federal government.[37] These agencies (the Bureau of Land Management (BLM), the National Park Service (NPS), and the U.S. Fish and Wildlife Service (FWS), all in the Department of the Interior (DOI); and the Forest Service (FS) in the Department of Agriculture) administer lands pursuant to different management missions and statutory authorities. As a result, permitting processes—including those required to access, construct, and operate electric transmission facilities on federal lands—can vary across agencies.

BLM manages approximately 240 million surface acres of federal lands, almost entirely located in the western United States, constituting the majority of onshore federal land.[38] BLM manages lands under its jurisdiction for varied purposes relating to the preservation, use, and development of the lands and natural resources, in accordance with the Federal Land Policy and Management

[33] Ibid. at 2773.

[34] Ibid. at 2773-2774.

[35] Ibid. at 2774.

[36] The Promoting Efficient and Engaged Reviews Act (PEER Act) discussion draft is available at https://www.epw.senate.gov/public/index.cfm/2023/5/carper-schatz-unveil-environmental-review-and-permitting-reform-proposal.

[37] See CRS In Focus IF10585, *The Federal Land Management Agencies*, coordinated by Katie Hoover.

[38] BLM, *Public Land Statistics 2022*, Table 1-3, at https://www.blm.gov/sites/default/files/docs/2023-07/Public_Lands_Statistics_2022.pdf.

Act of 1976 (FLPMA).[39] Transmission facilities on BLM-managed lands must conform with FLPMA as well as land use planning documents, called "resource management plans," mandated under FLPMA.[40]

BLM processes requests to build and operate transmission facilities as linear rights-of-way pursuant to FLPMA.[41] FLPMA authorizes BLM to grant rights-of-way for "systems for generation, transmission, and distribution of electric energy" and notes that such systems must also comply with any applicable requirements promulgated by FERC pursuant to the FPA.[42] BLM regulations implementing these provisions of FLPMA provide more detailed guidance, articulating the factors that BLM will consider in designating right-of-way corridors, including corridors for high-voltage electric transmission facilities.[43] These factors include but are not limited to environmental impacts on cultural and natural resources, potential public health and safety hazards, social and economic impacts, and previously developed transportation and utility corridor studies.[44] BLM has proposed amendments to these regulations that would also allow for consideration of "access to electric transmission" and would highlight "areas for solar and wind energy development with low potential for conflict with resources."[45]

BLM also issued an Information Memorandum in 2016 for the issuance of rights-of-way for high-voltage transmission lines across federal lands.[46] This memorandum calls for a "landscape-style approach" to land use planning in general and the authorization of rights-of-way for electricity transmission facilities in particular. This approach includes consideration of "baseline conditions, reasonably foreseeable impacts, including impacts that extend beyond the BLM's administrative boundaries, and the application of the mitigation hierarchy in the context of the conditions and trends of resources, at all relevant scales, consistent with applicable law. It also requires consideration of both direct and indirect impacts from the proposed action."[47] The reference to "direct and indirect impacts" suggests that the agency will consider not just the environmental, economic, and other impacts attributable to the transmission facilities themselves, but also those attributable to any electricity generation or consumption that would be enabled by the proposed right-of-way.

Other federal land management agencies have their own permitting processes that may account for other priorities. For example, NPS authorizes rights-of-way if the Secretary of the Interior determines them to be in the public interest, but there are also statutory restrictions on rights-of-way across national parks.[48] The FS issues "special use authorizations" that authorize utilities to construct and operate utility rights-of-way for the lands under its purview.[49] While the majority of federal land is managed by BLM, it is important to be aware of the possibility that one or more

[39] 43 U.S.C. §§1701 et seq.

[40] 43 U.S.C. §1712.

[41] 43 U.S.C. §1761.

[42] 43 U.S.C. §1761(a)(4).

[43] Implementing regulations can be found at 43 C.F.R. Part 2800. Note that applicants for rights-of-way to construct and operate transmission lines with a capacity of 100kV or more must comply with additional application requirements. See 43 C.F.R. §2804.12(b).

[44] 43 C.F.R. §2802.11(b).

[45] Rights of Way, Leasing, and Options for Renewable Energy, 88 *Federal Register* 39726, 39756 (June 16, 2023).

[46] BLM, Instruction Memorandum (IM) No. 2017-02, *Policy Guidance for Processing Right-of-Way Applications for High-Voltage Electric Transmission Lines*, November 18, 2016. Available at https://www.blm.gov/policy/permanent-im-2017-002.

[47] Ibid.

[48] 54 U.S.C. §100902.

[49] 36 C.F.R. Part 251, Subpart B.

rights-of-way for transmission service may be needed from a different agency with a different set of priorities pursuant to a different legal framework.[50]

Transmission lines may also be built offshore, for example in conjunction with offshore wind projects, several of which are under development off the Atlantic coast. Siting for such lines is under the authority of DOI's Bureau of Ocean Energy Management, as discussed in CRS Report R46970, *U.S. Offshore Wind Energy Development: Overview and Issues for the 118th Congress*, by Laura B. Comay and Corrie E. Clark.

Transmission Planning

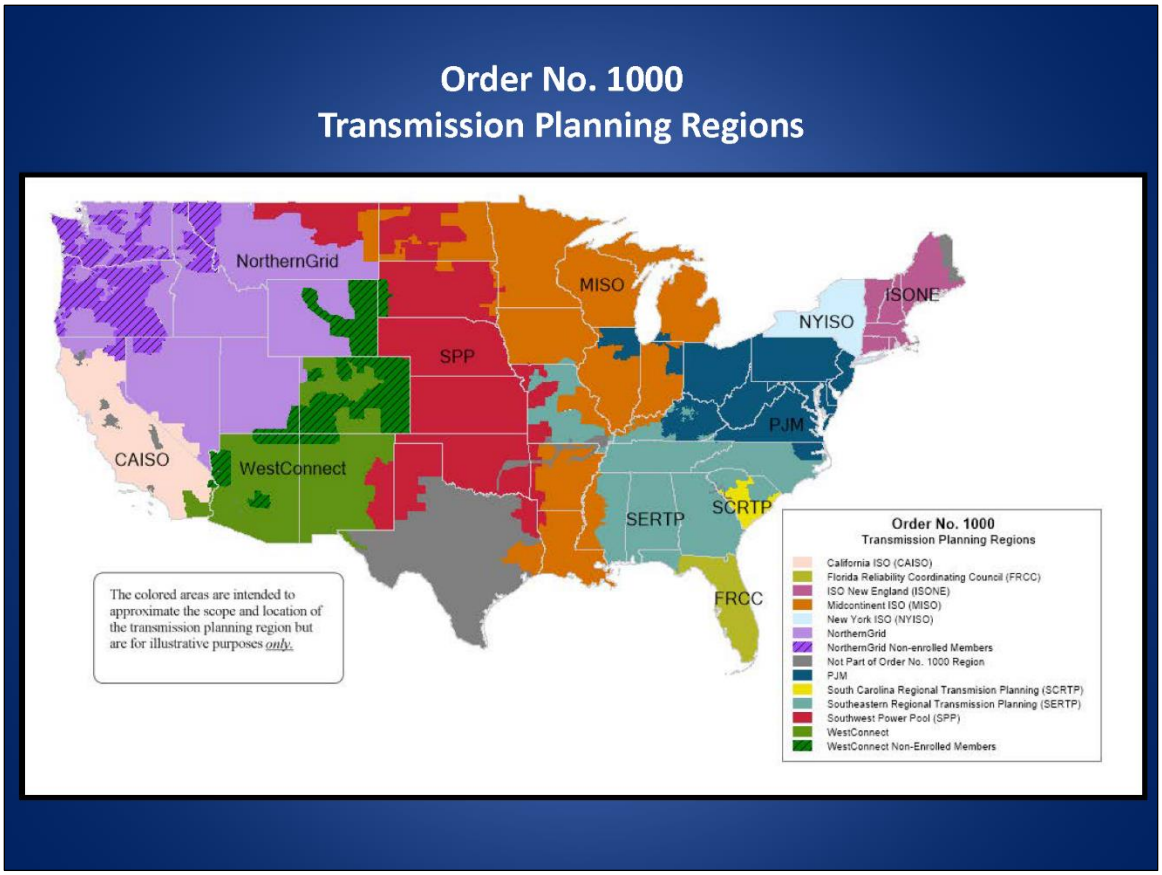
Before transmission lines can be sited, they must be planned. Transmission planning happens in both intrastate and interstate settings. It typically involves technical analysis projecting several years in the future to identify needed upgrades or expansions. Transmission planning might identify one or more types of system needs that new or expanded transmission lines could provide. Such needs include reliability improvements, opportunities for cost savings for customers, or requirements to achieve public policy goals (e.g., state renewable portfolio standards). Upgrades or expansions that fill those needs are sometimes referred to as reliability projects, economic projects, and public policy projects, respectively.

FERC oversees interstate transmission planning, primarily through Order No. 1000, issued in 2011.[51] That order requires coordinated, multistate regional transmission planning throughout much of the country (**Figure 2**). Order No. 1000 additionally requires coordination of interregional transmission planning for neighboring planning regions and a consideration of public policy needs. One goal of Order No. 1000 is to encourage the development of interstate transmission lines (i.e., regional projects) that often have cost savings and other consumer benefits compared to intrastate transmission lines (i.e., local projects). Some stakeholders argue Order No. 1000 has been ineffective at encouraging regional projects.

[50] See, for example, 54 U.S.C. §100902 (authorizing Interior to grant certain utility rights-of-way through the National Park System; Interior has delegated this authority to the National Park Service).

[51] "Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities (Order No. 1000)," 76 *Federal Register* 49842, August 11, 2011.

Figure 2. Order No. 1000 Transmission Planning Regions



Source: Federal Energy Regulatory Commission (FERC), https://www.ferc.gov/media/regions-map-printable-version-order-no-1000#.

Note: Alaska and Hawaii are not shown because they are outside FERC's jurisdiction for transmission planning.

FERC Proposal

In April 2022, FERC proposed changes to its transmission planning policies in a Notice of Proposed Rulemaking (NOPR) addressing several transmission-related topics (hereinafter, referred to as the Transmission NOPR).[52] The Transmission NOPR identified a number of deficiencies in FERC's current transmission policies, including (1) insufficient incentive for transmission developers to perform long-term assessment of transmission needs; (2) inadequate consideration of future transmission needs; and (3) failure to consider the broad potential benefits of transmission.[53] FERC asserts that these deficiencies lead to inefficient investments in transmission infrastructure, which ultimately lead to unnecessarily high costs for consumers.

One proposed change in the Transmission NOPR would address planning related to longer-term trends in the electricity system, including public policies (the Transmission NOPR does not

[52] "Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection, Notice of Proposed Rulemaking," 87 *Federal Register* 26504, May 4, 2022 (hereinafter, Transmission NOPR).

[53] Ibid. at 26511.

address planning related to reliability or economic projects). FERC proposed to require the use of Long-Term Regional Transmission Planning using a minimum 20-year planning horizon to consider possible changes in the resource mix and electricity demand.[54] Long-Term Regional Transmission Plans would be based on at least four Long-Term Scenarios that could vary by region but would include, at a minimum, seven factors prescribed by FERC. The proposed factors would include federal, state, and local laws, regulations, and goals; technology trends, including shifts towards electrification of end uses; and utility or consumer goals related to the electricity mix (e.g., decarbonization goals).

Another proposal in the Transmission NOPR would require transmission planners to explicitly consider two transmission technologies: dynamic line ratings and advanced power flow control devices.[55] These technologies can potentially allow more efficient use of existing transmission lines. In some cases, deploying these technologies could be a lower-cost option to meeting an identified transmission need.

Transmission Planning Proposals in the 118th Congress

Some legislative proposals would expand the requirements for regional transmission planning to broader geographic areas. For example, S. 1748, the Interregional Transmission Planning Improvement Act of 2023, would direct FERC to promulgate a rule addressing interregional planning (i.e., planning involving more than one region). S. 2480, the CHARGE Act of 2023, would direct FERC to require interconnection-wide transmission planning.

Additional information is in CRS Report R47627, *Electricity Transmission Permitting Reform Proposals*, by Ashley J. Lawson.

Cost Allocation

Cost allocation—determining which electricity consumers pay how much of the cost of building and operating a new transmission line—can be a contentious financing issue for new transmission lines. Cost allocation does not only directly affect consumers' rates, it can also affect siting decisions because state regulators may be more willing to site transmission lines if they believe the costs of the line have been allocated fairly (and vice versa).

Cost allocation generally relies upon the *cost causation* principle of electricity ratemaking, sometimes expressed as *beneficiary pays*. This principle requires that the beneficiaries of an electricity asset cover its costs and, conversely, that electricity consumers that do not receive benefits do not cover any costs. In practice, this means that cost allocation requires two steps. The first step is a determination of the beneficiaries of a transmission line. The second step is a determination of the share of costs that each beneficiary should pay. For transmission facilities affecting consumers within a small area, such as a single utility service territory, cost allocation is relatively straightforward because the benefits and costs are contained within that area. Transmission facilities crossing larger areas often have more complicated and more controversial cost allocation, especially when multiple states or planning regions are involved.

FERC has established principles for cost allocation, most recently in Order No. 1000.[56] The Order No. 1000 cost allocation principles apply to transmission lines selected through either a regional

[54] Ibid. at 26518-26533.

[55] Ibid. at 26552.

[56] "Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities (Order No. 1000)," 76 *Federal Register* 49842, August 11, 2011.

or interregional planning process. The Order No. 1000 cost allocation principles can be summarized as:

- Costs must be allocated "at least roughly commensurate with estimated benefits";
- Consumers that receive no benefit must not be involuntarily allocated any costs;
- If transmission planners use a benefit-to-cost ratio to select projects for which cost allocation applies, the threshold ratio for selection must not be too high;
- Costs must be allocated solely within the transmission planning region(s) in which the transmission line is selected, unless an entity outside the planning region(s) voluntarily agrees to assume a portion of the costs;
- The method and data used for cost allocation must be transparent;
- Transmission planning regions may use different cost allocation methods for different types of transmission investments.

FERC Proposal

The Transmission NOPR also addressed cost allocation. One proposed reform would identify a minimum set of transmission benefits that could be included in cost allocation methodologies. The proposed benefits are:

> (1) avoided or deferred reliability transmission projects and aging infrastructure replacement; (2) either reduced loss of load probability or reduced planning reserve margin; (3) production cost savings; (4) reduced transmission energy losses; (5) reduced congestion due to transmission outages; (6) mitigation of extreme events and system contingencies; (7) mitigation of weather and load uncertainty; (8) capacity cost benefits from reduced peak energy losses; (9) deferred generation capacity investments; (10) access to lower-cost generation; (11) increased competition; and (12) increased market liquidity.[57]

Another proposed reform would allow some interconnection-related upgrade costs to be eligible for regional cost allocation.[58] Interconnection-related upgrade costs are associated with some new power plants and occur when system upgrades may be required to protect the reliability of the system. Currently, many system operators require the proposed power plant to cover all or most of those upgrade costs. FERC's proposal would allow some upgrade costs to be spread among all consumers in a region under certain circumstances. The Transmission NOPR states this change would lower barriers to entry for new power plants (thus promoting competition) and help ensure that system costs are allocated in a manner at least roughly commensurate with estimated benefits (in line with the Order No. 1000 cost allocation principles).

A third proposed reform would encourage a portfolio-based evaluation of benefits, as opposed to evaluating the benefits of a single proposed transmission facility.[59] FERC believes this approach could result in a more stable or even distribution of benefits because it would be subject to less uncertainty than a project-specific analysis. Reduced uncertainty about benefits could facilitate agreement on regional cost allocation.

The Transmission NOPR additionally would require consultation with affected states in determining the processes for selecting projects for cost allocation and the method(s) for cost

[57] Transmission NOPR at 26539. [changing format to be consistent with above reference to FR pages]

[58] Ibid. at 26535-26538.

[59] Ibid. at 26546.

allocation.[60] It would also provide an opportunity for states to negotiate alternative cost allocation methods for individual projects.[61]

Transmission Cost Allocation Proposals in the 118th Congress

Some proposals in the 118th Congress would require FERC to enforce cost allocation based on a broad set of principles, generally in line with those FERC proposed in the Transmission NOPR. For example, S. 2480, the CHARGE Act of 2023, would direct FERC to adopt cost allocation policies accounting for 12 benefits of transmission stated in the bill. Additionally, the CHARGE Act of 2023 would prohibit, to the extent practicable, certain cost allocation methodologies such as those that "discourage distributed generation, energy efficiency, demand response, or energy storage if more economic than transmission."[62] In other words, this proposal aims to keep a level playing field between transmission expansion and non-transmission alternatives in the context of cost allocation.

Additional information is in CRS Report R47627, *Electricity Transmission Permitting Reform Proposals*, by Ashley J. Lawson .

Conclusion

Electricity transmission facilities are long-lived (typically 50 years or more), so investment decisions in the near term are likely to influence the nature of the U.S. electricity system through much of this century. While many decisions on siting and operation are left to state governments, federal policies affect the pace of investment and the decisions about what types of facilities to build, and recent legislation has given FERC an increased role as a backstop transmission siting authority. Agencies (such as FERC and BLM) have proposed changes to their transmission policies in the last few years, and legislative proposals in the 118th Congress would seek additional changes. Congress could evaluate the status of the U.S. electricity transmission system and consider whether policy changes are warranted.

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[60] Ibid. at 26557.

[61] Ibid. at 26558.

[62] S. 2480 §4(a)(1)(G)(i).

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