STATE POLICIES TO ADVANCE TRANSMISSION MODERNIZATION AND EXPANSION

Americans for a Clean Energy Grid

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EXECUTIVE SUMMARY

Transmission is the backbone of the electric grid — needed to deliver electricity from where it is produced to where it is used. Transmission plays a central role in ensuring that electricity, one of the country's essential services,[1] remains affordable, reliable, and resilient. There is widespread acknowledgment that the U.S. transmission system is aging and must be expanded and modernized. In much of the country, the existing transmission network has insufficient capacity to meet evolving and growing energy demands and interconnect new generating sources. In many places, the existing network also is not robust enough to allow power imports from neighboring regions during severe weather events when local transmission is strained or inoperable. Despite these shortcomings, recent transmission development in much of the country has been inefficient at best — and in some areas, sporadic or nonexistent.

Americans for a Clean Energy Grid (ACEG) commissioned this report to explore the role that state policies can play in advancing cost-effective transmission modernization and expansion — particularly the legislative policies that can advance the high-capacity interstate transmission solutions needed to ensure reliable and affordable electric service. Although the federal government, through the Federal Energy Regulatory Commission (FERC), has jurisdiction over interstate electricity transmission, states have numerous reasons to act proactively to ensure transmission planning and development are comprehensive and cost-effective, including because insufficient and poorly planned transmission can have negative impacts on their citizens' health, safety, and welfare; energy affordability; and economic development. Most states are also responsible for reviewing transmission permit applications and making transmission siting decisions.

This report is designed for advocates that work with state policymakers, and for engaged state policymakers themselves, to help them better understand potential state policies that can be used to advance a cost-effective and robust transmission grid for the benefit of ratepayers. Through surveys and interviews, transmission experts — including advocates, utility staff, transmission developers, and engaged state legislators — were asked to identify the key state policies (including legislative,

1 Essential services are services that are needed to safeguard human health and that are central to a strong working economy, including electricity, water, and (particularly in cold weather areas) heat.

executive, and regulatory actions, whether existing, pending, or failed) that are or would be most impactful in terms of either advancing or hindering transmission expansion or modernization. This report presents the insights offered by these experts, highlighting policies and actions that other states can learn from and adapt to their situations.

Because the electric network is integrated — electrons travel over connected wires without regard to state borders — and because the greatest value comes from high-capacity regional and interregional transmission, one state's policies alone will not fully resolve all challenges facing transmission modernization and expansion. The experts surveyed for this report, however, agreed that states play a critical role in advancing interconnected high-capacity transmission by

- enacting helpful policies;
- engaging in collaborative discussions within the state; with neighboring and other electrically interconnected states; with transmission owners, transmission developers, energy customers, and other interested parties; with regional planners; and with the federal government;
- participating meaningfully in regional and interregional planning processes; and
- raising the level of awareness around transmission needs and benefits.

Experts noted that there is no single panacea for all states because the variations in players, factors, and regulatory structures affect which policies will be most impactful. Nevertheless, experts noted that the most impactful policies and discussions seek to:

- support the principles of reliability, resilience, and affordability;
- encourage collaboration at all levels — including within the state, with other jurisdictions, with regional planners, and with other interested parties — with the goal of planning and building a robust interconnected electric network;
- promote comprehensive and coordinated regional and interregional grid planning that fully considers transmission modernization technologies and transmission expansion options and employs longer time horizons (20+ years) to select the most cost-effective solutions for customers;
- recognize the full suite of benefits that transmission can provide and allocate costs equitably among beneficiaries; and
- facilitate robust and streamlined processes for siting transmission lines and to include in such processes early and meaningful engagement opportunities and support for potentially impacted communities and landowners.

Experts also noted that state policies, and the implementation of such policies, can create significant barriers that hinder the development of needed transmission

capacity. In particular, they called out policies that:

- plan only for short term needs, especially given that transmission lines have a 50+ year lifespan;
- fail to account for the benefits provided by an interconnected network and instead silo the state into considering only whether electrons are delivered within the state or seek to protect in-state generation resources at the expense of customers and grid reliability; and
- increase bureaucracy and inefficiencies, including by duplicating regulatory processes.

Notwithstanding the potential for state policies to erect barriers, experts surveyed for this report were excited about the opportunities for increased state engagement on transmission. They encouraged states to improve not only their own state policies but to collaborate with neighboring and other electrically interconnected states to adopt similar policies to amplify the impact on regional and interregional planning and development. This report is intended to support such action.

The report is divided into two parts and an appendix.

Part I provides background on the need for transmission expansion and modernization, key players in transmission development, and the authority and role of states in transmission.

Part II delves into the policies identified by the surveyed experts as playing critical roles in helping or hindering transmission development, in particular high-capacity interconnected transmission solutions, and provides specific examples where available. Table I provides a summary of the types of policies identified by experts. It is important to note that this report does not provide a comprehensive review of every potentially relevant existing state policy, nor even a comprehensive list of examples for the policy types covered. Rather, it provides an illustrative sample of policies that experts identified as central to supporting transmission development and expansion. In short, this report is meant to support policy development and inform conversations but is not an encyclopedia of state action.

The **appendix** provides excerpts of legislative and regulatory language from some of the state policies discussed in the report.

TABLE 1. **State Policies Identified by Experts as Key to Expanding Transmission Capacity.**

Category	Issue	Policy Types
Planning	Current planning processes are failing to result in the development of transmission needed to meet current and future electricity needs. Issues plaguing planning include inadequate coordination, myopic short-term timelines, and restricted inputs into the planning process.	• Support states in participating meaningfully in regional transmission planning processes • Promote the development of actionable, long-term transmission plans by including transmission considerations in utility integrated resource planning processes, pairing transmission planning with the identification of energy resource zones, and directing state agencies to conduct stand-alone statewide transmission studies that can help inform regional and interregional transmission planning processes • Encourage utilities and transmission planners to evolve transmission planning assumptions and selection factors to study multiple scenarios over longer timelines and to consider comprehensive benefits • Encourage greater coordination between state agencies and between neighboring and other electrically interconnected states on setting planning assumptions and conducting planning processes
Siting and Permitting	Bureaucratic processes and local opposition to projects can delay the development of transmission projects.	• Reduce duplication within a state and between: federal and state permitting processes, regional planning and state processes, and neighboring states • Maximize use of existing rights-of-way such as along highways or railroad tracks • Require early and collaborative engagement with communities and offer direct benefits for the communities that are hosting projects • Recognize and attach value to the full suite of benefits that the state can receive from a strong regional and interregional transmission network

Category	Issue	Policy Types
Costs and Financing	Transmission projects are capital intensive projects, the costs of which ultimately fall on end use customers.	• Engage proactively and productively in regional and interregional cost allocation discussions to develop methodologies that consider the full suite of benefits so costs are shared equitably • Provide public funding, or leverage public or public-private financing opportunities, to reduce the total project costs and, accordingly, the costs passed onto ratepayers
Strengthening State Agencies' Ability to Engage in Transmission Planning and Development	State engagement in transmission planning and development can be both bureaucratic and inadequate, raising barriers to participate in regional planning processes and causing delays in processing transmission proposals.	• Enhance staffing and technical resources available to state agencies • Coordinate transmission-related education and engagement between state agencies and with other interested parties • Consolidate transmission support and decision-making in a state transmission authority
Transmission Modernization	Upgrading existing lines can achieve significant benefits. Modernization entails the integration of advanced transmission technologies (ATTs), including grid enhancing technologies (GETs) and high-performance conductors, to help unlock greater capacity on the existing grid. ATTs, however, are not being deployed to the full extent possible.	• Direct utilities and relevant state authorities to study GETS and high-performance conductors in state-level planning or permitting processes • Where legally sustainable, provide financial incentives for investments in transmission modernization • Create an environment that encourages the implementation of ATTs, for example by exempting such action from permitting requirements or through setting operational standards in wildfire safety policies
Creating an Ecosystem that Supports Robust Transmission Planning and Cost-Effective Development	There are regulatory, economic, and other conditions that can indirectly impact transmission development. Other reforms can be helpful in supporting more robust planning and cost-effective transmission modernization and expansion.	• Address other state policies, e.g., economic development and clean energy policies, with cost-effective solutions such as more robust transmission planning • Reform state regulatory and regional planning processes • Enhance workforce capacity

TABLE OF CONTENTS

PART I
BACKGROUND

A. THE IMPORTANCE OF TRANSMISSION EXPANSION AND MODERNIZATION

1. Historical Context: Expansion of the Transmission Network

Transmission has long played an integral role in maintaining a reliable and affordable electric network. Over the course of the early to mid-1900s, the growth of the U.S. transmission network:

- **Enabled greater access to power and supported the growth of the U.S. economy** – Transmission allowed larger movements of power in quantities sufficient to meet the nation's growing power demands, bolstering economic growth. Moreover, because transmission is resource agnostic — it carries electricity regardless of the generating source — it has easily adapted to the growth and evolution of generation technologies.
- **Facilitated economies of scale** – Because transmission allows power to move over long distances, the growth of the transmission network enabled the development of large-scale generating sources located away from population centers. The larger units generated power at a lower overall cost per unit of energy than the original local small generators. Traditionally, each utility was obligated to build sufficient generation to meet the peak load (i.e., highest demand on any given day) in its footprint, plus additional generation to provide a margin of safety in case a generator went down. Through transmission interconnections, utilities were able to pool their resources and reduce the overall generation needed to meet these resource adequacy requirements.
- **Increased reliability and resiliency** – Transmission allowed neighboring utilities to integrate their electric networks, which not only let them pool their resources to build larger generating sources, but also enabled them to import power when needed, such as during disruptive weather events and when power demands increased due to extreme heat or cold.

OVERVIEW OF THE U.S. ELECTRIC SYSTEM

The U.S. electric network is comprised of three main components:

- **Generating facilities**, which convert an energy input — such as solar energy, wind energy, water (i.e., hydroelectric) power, nuclear power, or a fossil fuel (e.g., coal or gas) — into electricity;
- **Transmission facilities**, which include the higher-voltage wires and associated infrastructure used to move power from large generators to the distribution network; and
- **Distribution facilities**, which include the lower-voltage lines and associated infrastructure used to move power from transmission lines to the homes, businesses, and manufacturing facilities that use the power (known collectively as end use customers).

The delineation between transmission and distribution facilities is both a technical and legal question. On the technical end, electric lines with a voltage of 69 kilovolts (kV) or less (along with their associated facilities) tend to fall on the distribution side of the spectrum. Electric lines with a voltage greater than 69 up through 230 kV are usually referred to as lower-voltage transmission lines (not to be confused with low-voltage distribution lines), whereas lines with a voltage greater than 230 kV (e.g. 345, 500, and 765 kV) are referred to as high-voltage transmission.

On the legal end, the Federal Energy Regulatory Commission (FERC) uses a seven-factor test to determine if a facility is considered transmission or local distribution, considering factors such as proximity to retail customers, local usage of power, the extent to which power flows into versus out of a system, and the system voltage.[a] However, the seven factor test is not a bright-line rule, as FERC will also take into account "other case-specific factors in particular situations."[b]

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a Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission on Servs. by Pub. Utils.; Recovery of Stranded Costs by Pub. Utils. & Transmitting Utils., Order No. 888, 61 Fed. Reg. 21,540, 21,619-20, 21,620-21 (May 10, 1996), FERC Stats. & Regs. ¶ 31,036, at 31,760-763 (1996) (cross-referenced at 75 FERC ¶ 61,080)(Order No. 888), *order on reh'g*, Order No. 888-A, 62 FR 12274 (Mar. 14, 1997), FERC Stats. & Regs. ¶ 31,048 (cross-referenced at 78 FERC ¶ 61,220), *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part sub nom. Transmission Access Pol'y Study Grp. v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. N.Y.* v. FERC, 535 U.S. 1 (2002).

b So. Cal. Edison Cmpy, 153 FERC ¶ 61,384, at PP 3-4 (2015).

2. Why the Grid is Insufficient for Current Needs

Although the transmission network continues to play a vital role in supporting reliable and affordable electric service, the status quo transmission network is no longer sufficient to meet the nation's current and future needs because:

- **The network is aging** – Much of the transmission network was constructed in the 1950s and 1960s, with a 50-year lifespan.[2] These facilities have not only reached and exceeded their useful life, but they are also less efficient in transporting energy than modern technologies.
- **Extreme weather and wildfire events are increasing**[3] – Wildfires and extreme weather events (including winter storms, hurricanes, tornadoes, and dangerously high summer temperatures) can have negative impacts on generation. For example, the weather may prevent fuel that is needed to generate electricity from being available, or weather conditions may make it unsafe for units to operate. Transmission allows utilities to import power from electrically connected regions that are unaffected or less impacted, thereby helping to prevent system blackouts. Some regions, however, lack sufficient interties with their neighbors to import power when needed, which can result in energy price spikes, rolling blackouts, significant economic losses, and most tragically, loss of life.[4] Moreover, integration of advanced transmission technologies, which can help reduce the risk of a transmission line causing a wildfire, remains quite limited.
- **Electric demand is shifting and, in some areas of the country, increasing dramatically** – In the first two decades of this century, electricity demand was relatively flat in much of the United States,[5] but that is no longer the case. With a resurgence in domestic manufacturing, expansion of data centers, and the commercial, industrial, and transportation sectors' interest in electrification, electricity demand is on the rise. A recent report found that in 2023, grid planners "nearly doubled the 5-year load growth forecast" through 2028.[6] The existing transmission network does not have sufficient capacity available to accommodate these growing loads, and the time it takes to plan and construct new transmission infrastructure often lags behind the emergence of new demand. Moreover, because most of the country's transmission planning

2 American Society of Civil Engineers, "Policy Statement 484 - Electricity Generation and Transmission Infrastructure," Adopted by the Board of Direction on July 13, 2019; *see also* Department of Energy, "What does it take to modernize the U.S. electric grid?," (stating that "70 percent of transmission lines are … approaching the end of their typical 50–80-year lifecycle"), last accessed Aug. 15, 2024.

3 *See, e.g.* Kenward, Alyson, et al, "Power Off: Extreme Weather and Power Outages," Sept. 2020 (finding that major power outages from weather-related events increased 67% between 2000 and 2020).

4 *See, e.g.,* Goggin, Michael, "Transmission Makes the Power System Resilient to Extreme Weather," American Council on Renewable Energy, July 2021 and Goggin, Michael and Zach Zimmerman, "The Value of Transmission During Winter Storm Elliott," Feb 2023 (discussing the devastating impacts of Winter Storms Elliott and Uri and other extreme weather events).

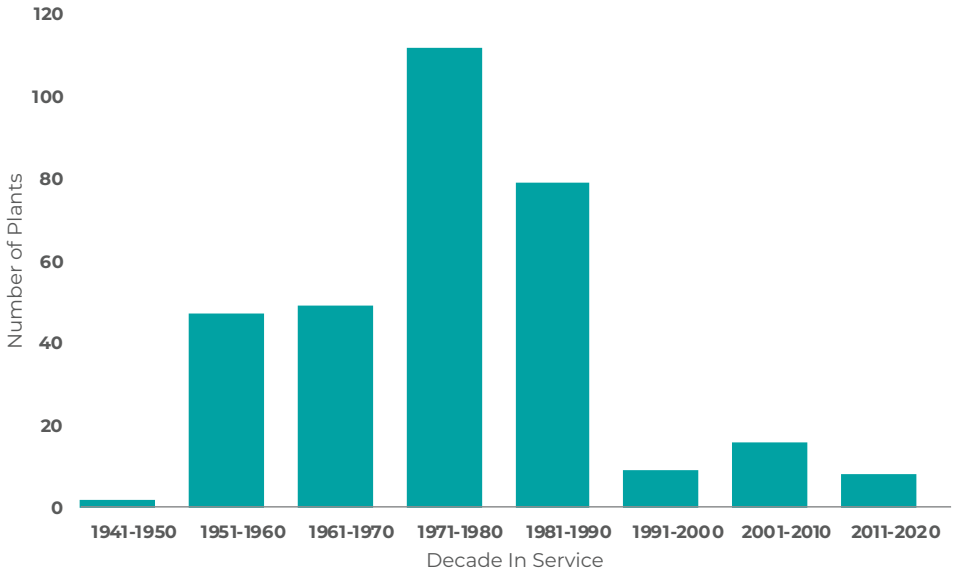
5 *See, e.g.,* U.S. Energy Information Administration, "Electricity Explained: U.S. electricity retail sales to major end-use sectors and electricity direct use by all sectors, 1950-2022," last accessed July 22, 2024.

6 Wilson, John D. and Zach Zimmerman, "The Era of Flat Power Demand is Over," Grid Strategies for the Clean Grid Initiative, Dec. 2023.

processes are reactive rather than proactive, many grid plans do not adequately account for these new load drivers.[7]

- **Traditional generating plants are aging, and customers are demanding domestically produced, cleaner energy sources** – Just as the transmission system is aging, so too are some of the large-scale, traditional generation facilities. For example, the majority of U.S. coal-fired plants were constructed more than 40 years ago (*see Figure 1*); this means most U.S. coal plants are reaching or are past their useful lifespan. Moreover, many customers (regardless of location or political affiliation) and states are demanding domestically produced electric energy sources, such as solar and wind generation, to decrease reliance on foreign energy supplies, to lower power costs as newer generation source are often less expensive than traditional generation sources, and to reduce carbon emissions arising from the electric grid.[8] New and expanded transmission must be built to interconnect the new generation sources (regardless of fuel type) needed to replace retiring generators and meet increased demand.

FIGURE 1. **In-Service Date of Conventional Steam Coal Electric Generation Plants Operating in the United States**



Data Source: EIA Form 860 Monthly Update, May 2024.

7 As explored further in the text box on Order No. 1920 (*see Part I.E*), FERC's recent transmission and cost allocation rulemaking aims to address the need for proactive, long-term transmission planning.

8 *See, e.g.* Wilson, Adam and Tony Lenoir, "Corporate Renewable Energy Outlook 2023," S&P Global Market Intelligence, March 2023.

- **The energy system must remain reliable and affordable** – The percentage of gross household income that is spent on energy services (i.e., "energy burden") varies by state and county; in some communities, it can be higher than 30%.[9] Failure to modernize existing transmission lines by incorporating advanced transmission technologies and to appropriately expand the system is exacerbating the energy burden that customers face. Due to insufficient transmission capacity, lower-cost generating resources cannot interconnect to the grid and reach customers.[10] In some regions, generating plants are seeking to retire, but transmission constraints mean such action would result in a generation shortage; consequently, customers are being required to pay hundreds of millions of dollars in reliability or power purchase contracts to continue to operate the uneconomic generating plants while waiting for the transmission constraint to be resolved.[11] Regions with persistent capacity constraints (i.e., areas where there is insufficient transmission capacity to allow for the full and needed flow of electrons) are subject to high congestion costs. Moreover, inefficient investment in transmission requires customers to pay more overall for multiple energy solutions than they would for one comprehensive solution.
- **Insufficient investment in high-capacity projects** – Investments in high-voltage transmission projects can offer a greater suite of benefits and solve electric system needs more cost-effectively, but can be challenging to plan, permit, and pay for. Due to the limitations in most current transmission planning processes — including with respect to how they approach planning timelines and transmission needs and benefits — very few high-voltage transmission facilities have been developed.[12]

B. ADDITIONAL TRANSMISSION CAPACITY NEEDS

To meet current and future needs, it is imperative to both unlock the full potential of the existing system (modernization) and build significant amounts of new transmission

9 *See, e.g.* Department of Energy, "Low-Income Energy Affordability Data (LEAD) Tool and Community Energy Solutions," last accessed July 22, 2024.

10 *See, e.g.* Lawrence Berkeley National Laboratory, "Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection," last accessed Aug. 15, 2024.

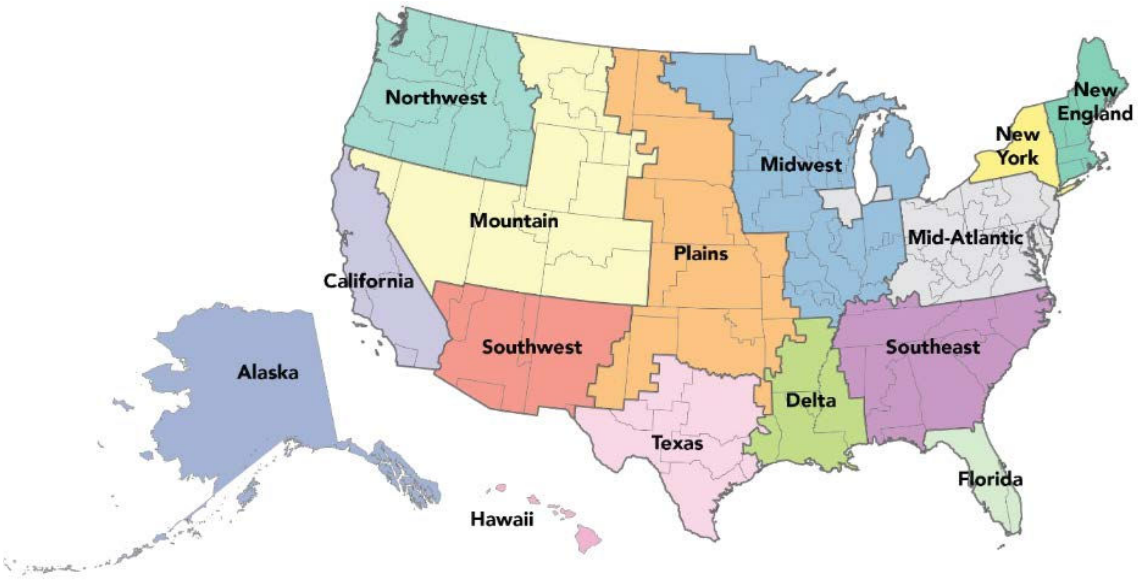
11 For example, in PJM, a generation owner's request to retire Brandon Shores, a coal-operated power plant that the generation owner found is no longer economically feasible to operate, would trigger the need for $785 million in transmission system upgrades that will likely take until December 2028 to complete. *PJM Interconnection LLC*, 185 FERC ¶ 61,107 (Nov. 8, 2023). PJM determined it must execute reliability must run agreements to keep the plant running while the upgrades are being completed, for which the generation owner is requesting a monthly fixed-cost charge of $14.6 million. *H.A. Wagner LLC and Brandon Shores LLC*, 187 FERC ¶ 61,176 (June 17, 2024) (as of Aug. 2024, this proceeding has been submitted to a FERC settlement judge, *see* FERC Docket No. ER24-1787 for more information).

12 Shreve, Nathan, Zachary Zimmerman, and Rob Gramlich, "Fewer New Miles: The US Transmission Grid in the 2020s," July 2024 (explaining that "90% of transmission investment is driven by lower voltage reliability needs, developed without regard for other values that can be served by transmission.").

(expansion). Experts have varying opinions on the amount of increased transmission capacity required, but analyses by the U.S. Department of Energy (DOE) provide a sense of the overall scale of the need.

In October 2023, DOE issued its latest National Transmission Study "to identify transmission needs that are currently harming customers or expected to do so in the future and that could be alleviated by transmission solutions."[13] DOE examined needs for both regional transmission and interregional transmission based on the regions shown in Figure 2.

FIGURE 2. **Geographic Regions Used in DOE's National Transmission Study**

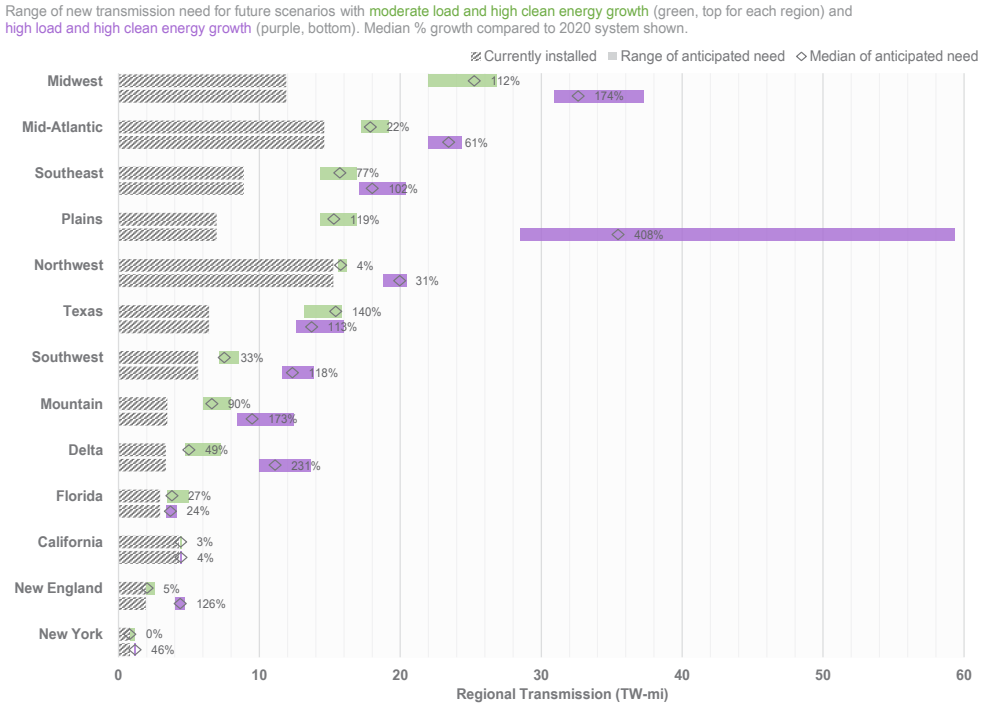


Source: U.S. Department of Energy, "National Transmission Needs Study," at iii, 2023.

DOE found that under both moderate and high load-growth scenarios (each of which factored in high levels of clean energy growth), significant regional (*Figure 3*) and interregional (*Figure 4*) transmission is needed throughout the country, particularly in the Plains and Midwest regions, as well as between the Plains and its neighbors to the east, the Midwest and Delta regions.

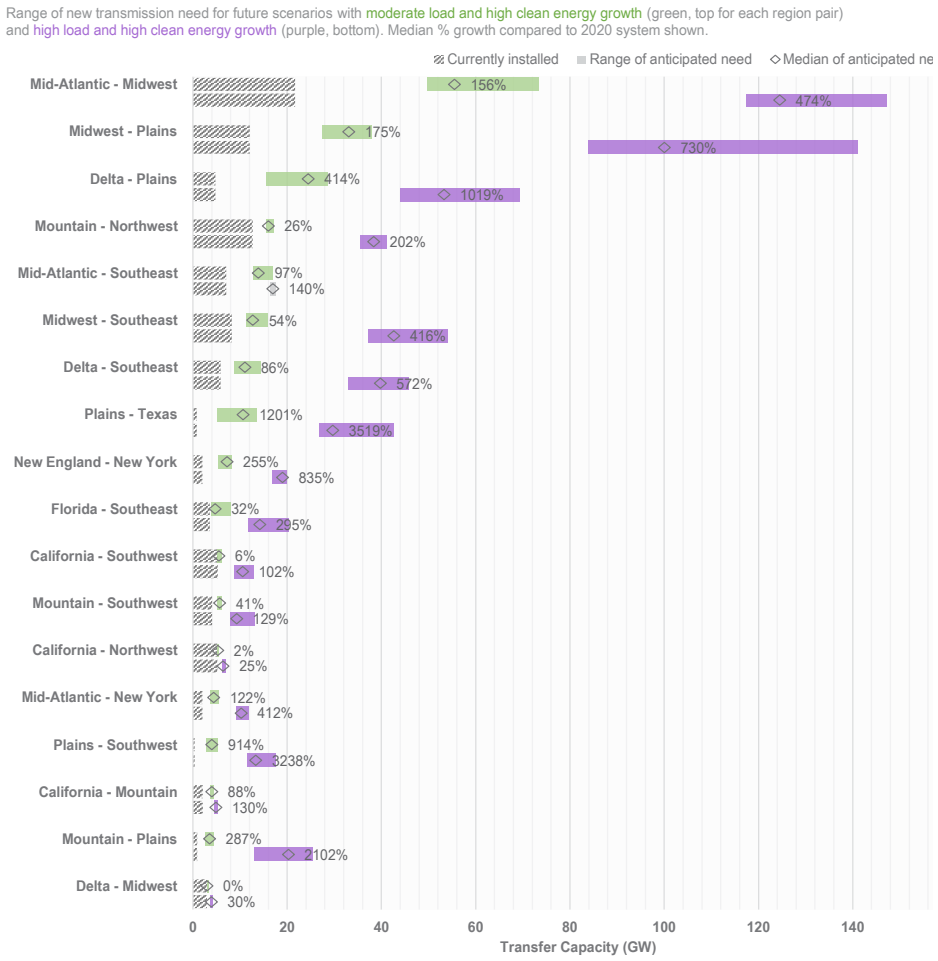
13 U.S. Department of Energy, "National Transmission Needs Study," at ii, 2023.

FIGURE 3. **Anticipated Regional Transmission Need in 2035**



Source: U.S. Department of Energy, "National Transmission Needs Study," at ix, 2023.

FIGURE 4. **Anticipated Interregional Transmission Need in 2035**



Source: U.S. Department of Energy, "National Transmission Needs Study," at ix, 2023.

C. ROADBLOCKS TO TRANSMISSION EXPANSION AND MODERNIZATION

There are several issues that can present barriers to cost-effective and timely transmission expansion and modernization. The most commonly discussed issues fall into categories that some experts refer to as the "three P's of transmission": planning, permitting, and paying.

- **Planning** refers to the processes used to analyze electric network system needs, determine how much additional transmission capacity is required to meet those

needs, and select the portfolio of projects that should be constructed. In much of the nation, planning processes are cursory and reactive, examining only past or near-term (three to five years) reliability problems. These planning processes fail to assess long-term transmission needs (e.g., what changes are expected over the 20-year estimate utilized to evaluate needed resources in most integrated resource plans or the 40+ year timeline that the transmission facilities will be in service) and the full suite of benefits that will accrue to customers if transmission is expanded and modernized. Moreover, when planning is siloed to examine needs only within one state or one utility footprint it can lead to the selection of projects with limited benefits that sideline the potential to develop more comprehensive solutions that both solve larger systems needs and are more cost-effective on a $/mile basis.

- **Permitting** refers to the processes that projects must undergo to receive all necessary federal and state permits before steel can be put in the ground. In much of the country, permitting processes tend to be protracted.[14] This category also includes siting processes, which refer to determining the actual locations of lines and the communities that lines will pass through. Historically, energy infrastructure has often been sited in marginalized and already overburdened communities without regard to the infrastructure's impacts and without adequate compensation for impacted communities.
- **Paying** refers to processes and decisions about who bears the costs for transmission projects, which are capital-intensive and which can have costs ranging into the billions of dollars. Although the benefits of well-planned transmission far outweigh the costs — and (as noted earlier) there are significant economic, health, and other costs associated with insufficient transmission build-out — allocating the costs of transmission has proven to be incredibly thorny. In particular, when transmission lines cross two or more transmission planning regions or two or more utility footprints within a planning region, transmission providers need to develop cost allocation formulas to determine how much of the project costs will be assigned to each utility whose customers benefit from that line.[15] This issue often boils down to which policies/system needs are assigned responsibility for "causing" the line to be built and who is purported to "benefit" from the lines. However, these determinations often are not very clear and can lead to protracted debates and accusations of inequities. Ultimately, the costs of developing and operating transmission lines are passed

14 For more information on permitting delays, *see* Niskanen Center and Clean Air Task Force, "Contextualizing electric transmission permitting: data from 2010 to 2020," pp.3, 6-7, 2024.

15 When a transmission line is built wholly within a single utility footprint, the entire cost of that line is generally assigned to customers in that footprint. If that single utility footprint crosses state borders, cost allocation is often based on the percentage of the utility's entire load located in each state.

through to end use customers, and, therefore, a key issue is whether steps are taken to help reduce the ratepayer burden (e.g., through robust planning and smart financing).

In addition to these three categories, there are several indirect or larger drivers that have hindered needed transmission development, including:

- **Inefficiencies arising from multiple interested parties who have a stake in the market process** – Transmission development is inherently buffeted by a myriad of competing forces because multiple entities with conflicting goals — primarily financial incentives — are working to advance their own interests. Their individual actions can be designed to, or have the impact of, undercutting transmission. For instance, a generator may profit from a region's lack of access to other low-cost resources, a transmission developer may seek to use regulatory mechanisms to gain an advantage over another, or one state may try to prefer generation within its own borders to provide local jobs.
- **Inefficiencies arising from shared responsibility over transmission planning and development** – Similar to the concern noted above, but even more specifically, multiple entities have a role in transmission planning and development, including federal and state agencies, private and government-owned utilities, transmission developers, regional transmission organizations (RTOs), regional planning organizations, landowners, and more. Their activities are often not well coordinated, leading to inefficiencies and conflicting understandings over the need for and the bottlenecks to transmission development. Additionally, the sharing of responsibility across federal, state, and local governments can raise contentious questions about preemptive authority and can result in inadequate oversight.
- **Politics** – Transmission modernization and expansion support electric reliability and resilience, national security, and affordable rates — all bipartisan issues — and additional transmission capacity is needed throughout the country to ensure these benefits. Nevertheless, because transmission facilitates the interconnection of new resources, including wind and solar resources, some have attempted to tightly link efforts to expand transmission capacity with advancing a climate and clean energy agenda, which has less bipartisan support. This political rhetoric has complicated efforts to improve transmission planning and permitting processes and advance cost allocation discussions.
- **Insufficient understanding of the transmission system** – Although electricity is needed for almost every aspect of modern life, few people think about or understand the inner workings of the electric system. Most people only think about electricity infrastructure when it fails them in some way (e.g., when

the lights do not turn on) and typically do not make the connection to the larger system. It is not surprising that, in some areas of the country, both state policymakers and the general public have a limited understanding of the need to expand the transmission system to provide safe and reliable service and the benefits that will accrue from a robust and well-planned transmission network. Given the technical, complicated nature of the electric system and the many years it can take to build transmission lines, state policymakers may give deference to the companies that traditionally own and operate lines to make decisions, which in some cases results in implementing only short-term fixes.

D. KEY PLAYERS IN TRANSMISSION DEVELOPMENT

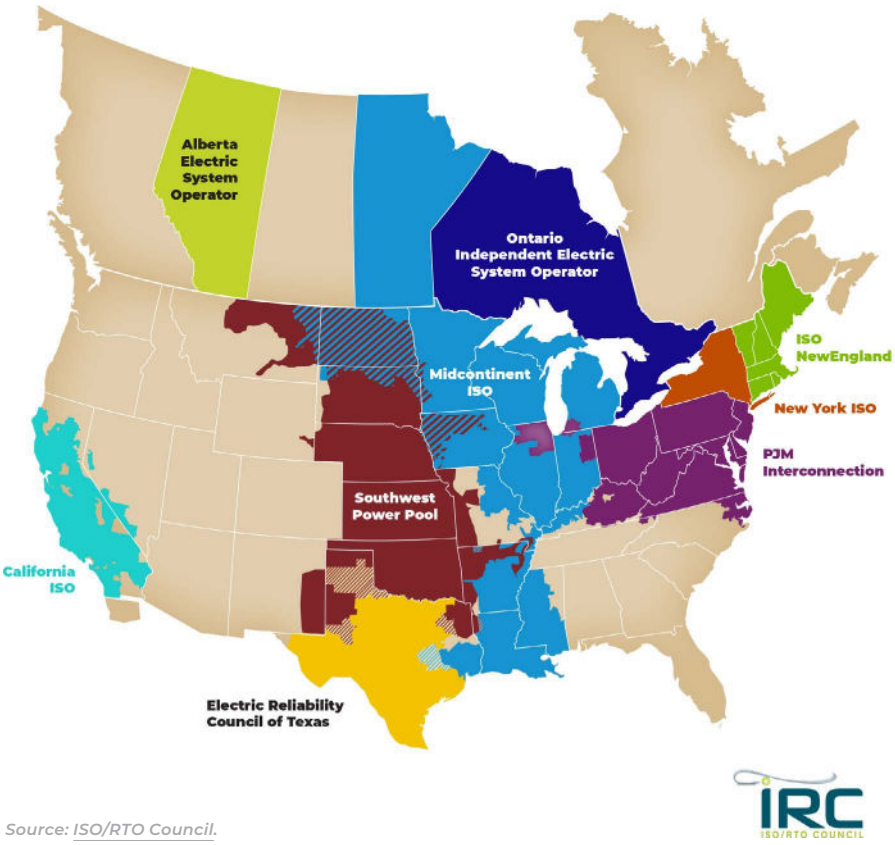
There are multiple players potentially involved in transmission planning and development. Who is involved varies widely depending on a host of factors related to the state (or sometimes the part of the state) in question. Below is a description of some of the major players in transmission planning and development.

Player	Role
Incumbent Utilities (also known as public utilities)	Utilities are the private, for-profit entities that have a franchise or other agreement to provide electricity service within a certain geographic footprint. Some utility footprints cross state borders. Historically, incumbent utilities were vertically integrated — owning the transmission, generation, and distribution resources needed to provide electricity service — but this structure has changed in some states. *With respect to transmission, utilities are subject to FERC jurisdiction over the rates, terms, and conditions of service and, in most cases, to state jurisdiction over permitting lines on non-federal and non-tribal land.*
Independent Transmission Companies	Independent transmission companies are for-profit companies that own and operate only transmission lines. Some formed when an incumbent utility spun off its transmission resources to a separate entity. In other instances, transmission-only developers seek to build lines, either based on their own due diligence or by competing for the ability to build a project. *Independent transmission companies are subject to FERC jurisdiction over the rates, terms, and conditions of transmission service and, in most cases, to state jurisdiction over permitting lines on non-federal and non-tribal land.*
Merchant Transmission Developers	Merchant developers are companies, usually private and for-profit, that do not have a set of captive ratepayers at the end of their lines. Some of these companies also own generation resources. They seek to recover the costs of their projects through private contracts with customers (also known as off-takers).

Player	Role
Municipal Utilities and Cooperatives	Also referred to as public power, municipal utilities (munis) and cooperative utilities (co-ops) are government-owned (in the case of munis) or governmentally-chartered and customer-owned (in the case of co-ops). Many munis and co-ops are transmission dependent, meaning that they own limited or no transmission and are dependent on neighboring utilities to move power to their customers. *Munis and co-ops are exempt from most federal jurisdiction and state commission jurisdiction.*
Power Marketing Administrations (PMAs)	There are four federal PMAs: Bonneville Power Administration, Southwestern Power Administration, Southeastern Power Administration, and Western Area Power Administration. The PMAs operate and sell power from large, federally owned hydroelectric systems and associated transmission and distribution systems. *PMAs are self-regulated by appointed Boards and are exempt from most FERC jurisdiction, notably jurisdiction to require transmission planning and cost allocation.*
End Use Customers	End use customers are the residential, commercial, and industrial entities that consume power, have the costs of transmission projects ultimately passed on to them, and bear the consequences when there is a lack of transmission. End use customers rely on FERC and state commissions to balance the public interest with the interest of private utilities to ensure that rates and service are just and reasonable and that utilities are economically viable.
Federal Energy Regulatory Commission (FERC)	FERC issues regulations on transmission planning to support the public interest and maintain just and reasonable rates, including its recently issued Order No. 1920 revising its planning and cost allocation rules. (*For more on Order No. 1920, see Part I.E.*) FERC has authority over the rates, terms, and conditions of transmission lines, but it does not have the authority to direct the selection or development of any particular lines.
Federal Agencies	If potential projects are located on or cross federal lands, the project will need to obtain permits from affected federal agencies (e.g., the Bureau of Land Management).
Tribal Governments	Tribal governments have a unique role in transmission development, as they have independent and autonomous governance authority, their citizens depend on the electric network, and land and cultural resources may be impacted by project siting. Their unique role is recognized by additional consideration and respect accorded through the government siting and permitting process. Additionally, some tribal governments have an ownership interest in transmission lines crossing their lands.
States and State Agencies	States have an inherent interest in ensuring a sufficient, cost-effective, reliable, and well-functioning grid to protect the health, safety, and welfare of its citizens and to promote a strong economy. Depending on the state, the state agencies that may play a role in supporting robust planning and/or regulating the development of transmission could include: state utility commissions, state energy offices, state siting boards, state transmission authorities, and state economic development agencies.

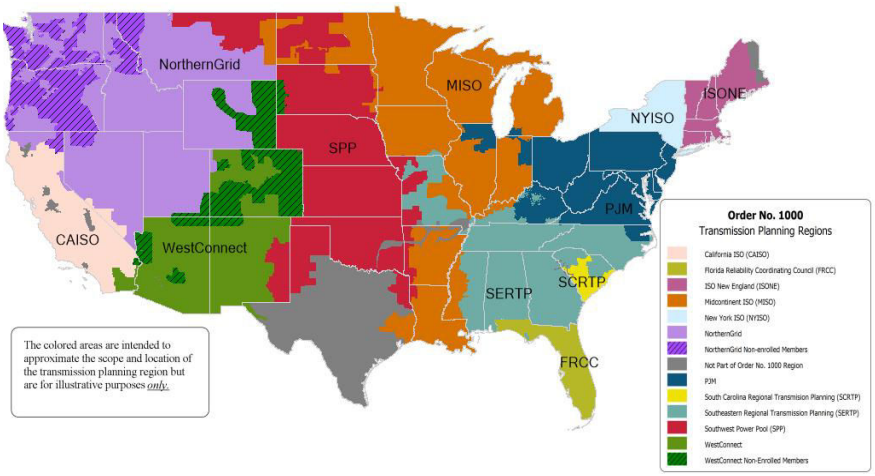
Player	Role
Local Governments	Local governments have an interest in ensuring that transmission is sited appropriately, taking cultural and economic resources into account, and that communities impacted by transmission development are adequately compensated. Additionally, in some states, the state has declined to exercise its authority over energy infrastructure-related land use decisions, thereby delegating its permitting authority to local governments.
Regional Transmission Organizations (RTOs)/ Independent System Operators (ISOs)	RTOs and ISOs were formed initially by neighboring utilities interested in pooling their transmission resources so they could be jointly and more efficiently operated. Over time, FERC issued orders that provided additional drivers for the formation of RTOs/ISOs (e.g., FERC Order No. 890). RTOs and ISOs operate but do not own transmission lines. There are three single-state ISOs (CAISO, ERCOT, and NYISO) and four multi-state RTOs (MISO, PJM, SPP, and ISO NE) (*see Figure 5*). With a few exceptions, the RTO/ISO boundaries do not align with state boundaries, and some states are divided among multiple RTOs/ISOs. In some states, part of the state is in an RTO/ISO and part is not. While all RTOs/ISOs are nongovernmental organizations, they vary considerably in structure. For instance, some are nonprofit organizations; others are not. Tariffs and governance structures for most RTOs/ISOs are reviewed and approved by FERC, but ERCOT is not fully interconnected to the rest of the U.S. grid so it is exempt from FERC jurisdiction for transmission planning and cost allocation, and conducts such processes exclusively under Texas state laws and regulations. Some RTOs/ISOs also manage energy, capacity, and/or ancillary service markets.
Regional Planners	In Order No. 1000, issued in 2011, FERC directed public utilities to engage in regional transmission planning. The planning regions overlap with RTO/ISO footprints, where they exist, while non-RTO areas are divided into their own planning regions (*see Figure 6*). Planning region boundaries often do not align with state boundaries. No two regional planning regions are alike. Some, such as MISO, take a more proactive role in transmission planning, while others, such as SERTP, take a more passive role and largely base the regional plan on what utilities identify as needed.
Generation Developers	Generation developers are independent developers who are building or planning to build utility-scale (i.e., large) generation projects, sometimes creating a need for additional transmission capacity. These entities are also referred to as independent power producers (IPPs).
Others	Additional interested parties can include tribal communities, agricultural communities, environmental, labor, and environmental justice groups, community and economic development organizations, local landowners, and more.

FIGURE 5. North American RTOs / ISOs



Source: ISO/RTO Council.

FIGURE 6. Order No. 1000 Transmission Planning Regions



Source: FERC, Order No. 1000 Transmission Planning Regions.

E. STATE AUTHORITY OVER AND ROLE IN TRANSMISSION EXPANSION AND MODERNIZATION

The state role in transmission expansion and development, and therefore the selection of effective state policies, is influenced by several factors:

- **The Federal Power Act (FPA)** – The FPA sets up a system of cooperative federalism under which the federal government and states share authority over the electric system. The FPA assigned the federal government authority over "the transmission of electric energy in interstate commerce and the sale of such energy at wholesale in interstate commerce," but federal regulation "extend[s] only to those matters which are not subject to regulation by the States."[16] This means that FERC regulates the rates, terms, and conditions of service for transmission lines owned by FERC-jurisdictional utilities, and states govern other issues such as the siting and permitting of transmission lines and the generation choices.

  However, these jurisdctional lines can get blurry. For example, although FERC reviews and approves all transmission costs that utilities are authorized to recover annually (known as utility transmission revenue requirements), vertically integrated utilities in some cases have "bundled" together the transmission charges and the generation charges for their retail customers, and those bundled rates are subject to state commission review. A state commission reviewing the bundled rate may decide how much of the FERC-approved revenue requirement may be passed onto retail customers; in these cases, FERC has declined to assert its jurisdiction over the transmission component of the bundled rates.[17] Conversely, although states generally have authority over transmission siting and permitting, Congress has given FERC backstop authority over permitting of transmission projects under certain conditions.[18]

- **Facility ownership** – As described above, there are several different forms of transmission facility ownership, some of which are subject to direct state regulation and some of which are not.

- **Regulated (vertically integrated) versus restructured (retail choice) states** – Historically, all incumbent utilities were vertically integrated, meaning they owned and operated the generation, transmission, and distribution systems

16 16 USC § 824.

17 *New York v. FERC*, 535 U.S. 1, 25-26 (2002) (finding that FERC provided "valid support" for its decision not to regulate bundled retail transmissions and that although "FERC chose not to assert such jurisdiction, … it did not hold itself powerless to claim such jurisdiction.") FERC's decision not to exercise its authority extends only to the transmission component of bundled rates; states do not have authority to conclude in setting retail rates that the FERC-approved wholesale rates are unreasonable. *Nantahala Power & Light Co. v. Thornburg,* 476 U.S. 953, 953 (1986) (FERC clearly has exclusive jurisdiction over the rates to be charged … [to] interstate wholesale customers).

18 16 USC § 824p.

within their footprints. In some states, incumbent utilities are still vertically integrated. In others, the state encouraged generation competition and directed their utilities to divest their generation. In these states, referred to as restructured, retail choice, or deregulated states, the incumbent utilities have either "functionally unbundled" their generation by owning/operating their generation resources through an affiliate or a functionally separate arm of the company, or they do not own any generation and own and provide service only over transmission and distribution wires.

- **Proactiveness of the regional planning organization** – Regional planning processes, and regional planner engagement, vary considerably. Generally, multi-state RTO/ISOs have more established processes to plan transmission on a regional basis, although the state role in these processes can also vary, especially as in some regions but not in others, state authorities have been granted voting rights in stakeholder processes.[19] Single-state RTO/ISOs tend to be more siloed with respect to planning interconnected transmission, but may coordinate well with other state agencies on matters related to energy goals, resource procurement, and load forecasting. In non-RTO/ISO regions, the strength of the regional planning also varies considerably and is even more complicated because there may not be a centralized and staffed entity to coordinate planning.

19 Compare MISO which grants certain voting rights in MISO's stakeholder process to state regulatory authorities on MISO's Advisory Committee to PJM where, with the exception of consumer advocates who represent end use customers, state authorities do not have a voting right. For more information on how individual regions perform on planning, see Americans for a Clean Energy Grid, "Transmission Planning and Development Regional Report Card," 2023.

FERC ORDER NO. 1920

In May 2024, FERC issued Order No. 1920, *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation*.[a] Among the rule's new elements are requirements for transmission providers to do the following:

- Produce long-term (at least 20-year) regional transmission plans at least every five years, which must utilize seven specific categories of forward-looking factors in scenarios, select projects based on seven specific economic and reliability benefits, and consider the use of grid-enhancing technologies.
- Open a six-month engagement period with relevant state entities regarding cost allocation before the transmission provider submits filings at FERC that propose a default method of cost allocation for long-term transmission facilities. Previously, transmission providers had no specific obligation to engage with states in determining cost allocation.
- Be more transparent about local transmission planning, including conducting local stakeholder meetings.

The rule also gives incumbent transmission owners a right of first refusal to develop "right-sized" replacements of existing transmission facilities to increase their capacity.

As of the writing of this report, the rule has been challenged in court by some states and defended by others. While the full impact of the rule is still being determined, experts suggested that two of the most important steps that states can take regarding Order No. 1920 are to: (1) codify the Order's planning guidelines, which represent best practice, in state policy, and (2) facilitate robust cost allocation discussions with the utilities and other states in their region.

a *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation*, Order No. 1920, 187 FERC ¶ 61,068 (May 13, 2024).

Given all the variations in players, factors, and regulatory structures, **there is no single clear answer (or set of answers) about what policies a particular state should adopt to accelerate transmission modernization and expansion — but there are important choices that will have a meaningful impact in overcoming the challenges that have hindered high-capacity transmission expansion and modernization**. The second part of this report covers the types of state policies that experts have identified as most impactful.

PART II
STATE POLICIES

To help policymakers think about their policy options and their roles (formal and informal), this section addresses the policies that experts identified as the most impactful for advancing expansion and modernization of U.S. transmission infrastructure.

A. PLANNING

Robust transmission planning is the cornerstone of maintaining a reliable, resilient, and cost-effective electric network that can meet changing electricity demands. Historically, utilities developed their transmission plans unilaterally, based on what was needed to support their generation sources and serve their end use customers. Through a series of orders, including Order Nos. 888, 890, 1000, and (most recently) 1920, FERC directed utilities to provide open and non-discriminatory access to their transmission systems, increase coordination and transparency in their planning processes, plan on a regional basis, use best available data, and engage in longer-term planning based on different scenarios. Notwithstanding FERC's actions, planning for high-capacity transmission remains inadequate in most regions of the country, due to factors such as insufficient coordination, truncated planning timelines, and restricted inputs into the planning process.

Many experts surveyed for this report emphasized that enhanced state engagement in transmission planning processes could help support cost-effective intra- and inter-regional transmission modernization and expansion to meet both current and future needs. In particular, experts noted that proactive and meaningful state engagement in regional transmission planning processes is needed to facilitate the development of robust regional plans and the selection of cost-effective portfolios of transmission projects. They further noted that when planning is restricted to only one state or one utility footprint, the resulting projects often provide a more limited benefit and can compound costs for customers when compared to the solutions derived from comprehensive regional and interregional long-term planning.

Experts suggested three types of policies that can help states enhance transmission planning efforts:

1. Promoting the development of actionable transmission plans that can help inform regional and interregional transmission planning processes.
2. Encouraging utilities and transmission planners to evolve transmission planning assumptions and selection factors to integrate multiple scenarios over longer timelines and to consider comprehensive benefits.
3. Encouraging greater coordination between state agencies and between neighboring and other electrically interconnected states on setting planning assumptions and conducting planning processes

1. Promoting the Development of Actionable Transmission Plans

Experts identified at least three ways that states can help advance the development of proactive and cost-effective transmission plans that provide a more holistic view of future electricity demand trends and generation changes:

- *By including transmission consideration in utility integrated resource plans;*
- *By pairing transmission planning with the identification of energy resource zones; and*
- *Through a stand-alone statewide transmission study that can help inform regional and interregional planning processes*

Experts also encouraged states to participate meaningfully in regional transmission planning processes and to share the results from their intrastate planning processes with regional planners to help encourage robust interstate transmission planning.

a) Utility Integrated Resource Plans

Integrated resource plans (IRPs) are utility-developed strategies focused on forecasting future energy needs, evaluating resource options, and planning cost-effective and reliable energy solutions. Not all states require IRPs; they tend to be required more in vertically integrated states and less in states that have moved to a retail choice model.[20] In states that do require IRPs, the IRP processes vary widely. One thing they generally have in common, though, is that the IRPs tend to focus on generation. If transmission is considered, It is usually examined only to the extent it is needed to support the generation choices, and/or there is an emphasis on minimizing transmission costs

20 The American Coalition of Competitive Energy Suppliers maintains an interactive map detailing whether a state is fully regulated or offers retail choice to some or all end use customers.

without considering the overall impact of that choice on which generation options will be available to the system or to the long-term health of the network and rate affordability.

Policymakers can play a direct role in shaping IRP requirements and the criteria that utility commissions should use to evaluate IRP proposals. Experts recommended that state policies integrate long-term transmission analyses into IRP requirements and ensure that the analyses co-optimize transmission and generation planning to find the right mix of solutions. For instance, experts pointed to a 2023 **Washington** law that updated the state's IRP requirements, directing utilities to include in their IRPs an assessment and 20-year forecast of regional generation and transmission capacity; the assessment must identify utilities' expected needs to develop new or expand/upgrade existing transmission facilities.[21]

Similarly, **Michigan** law requires utilities to file IRPs with five-, ten-, and fifteen-year projections of their load obligations and their plans to meet those obligations, including an analysis of new or upgraded transmission options.[22]

b) Pairing Transmission Planning with the Identification of Resource Zones

Several experts pointed to state policies that direct an examination of transmission needs in the context of developing energy resource zones. Energy resource zones are strategic locations where wind, solar, and/or other energy resources are abundant or areas where there are transmission constraints that prevent needed generation from coming online.

For example, experts pointed to **Texas**' Competitive Renewable Energy Zones (CREZ) policy (which was adopted in 2005 and repealed in 2023). The policy required the Texas Public Utilities Commission, in consultation with the Electric Reliability Council of Texas (ERCOT), to designate renewable energy zones and "develop a plan to construct transmission capacity necessary to deliver to electric customers, in a manner that is most beneficial and cost-effective to the customers, the electric output from renewable energy technologies in the competitive renewable energy zones."[23]

Experts also pointed to the Climate and Equitable Jobs Act (CEJA) in **Illinois**.[24] Through CEJA, Illinois directed the Commission to develop a Renewable Energy Access Plan (REAP) that includes designation of REAP zones and "a plan to achieve transmission capacity necessary to deliver the electric output from renewable energy technologies

21 Washington SSB 5165 (2023) (updating RCW 19.280.030).
22 MCL § 460.6t.
23 Texas SC 20, Sec. 3 (2005) (amending TX Utilities Code § 39.904, since repealed).
24 Illinois Public Act 102-0662.

in the [REAP] zones to customers in Illinois and other states in a manner that is most beneficial and cost-effective to customers."[25] Moreover, recognizing that Illinois is partially in MISO and partially in PJM, CEJA requires the Commission's REAP to "consider proposals to improve regional transmission organizations' regional and interregional system planning processes."[26]

In addition, experts mentioned a somewhat similar law in **Colorado**, which requires electric utilities, every two years, to designate "energy resource zones" where transmission constraints hinder the delivery of electricity and/or the development of new electricity generation; to develop plans for transmission facility construction or expansion needed to deliver energy resources in or near such zones; and to consider how provision of transmission could encourage local ownership of renewable energy facilities.[27]

Maryland likewise tied transmission planning to renewables development, albeit in a slightly different way. In 2023, Maryland enacted the Promoting Offshore Wind Energy Resources Act (POWER Act), which, among other things, required the Public Service Commission to ask PJM Interconnection to analyze options to upgrade and expand the transmission system to accommodate the desired buildout of offshore wind.[28]

c) Stand-Alone Statewide Transmission Studies

Beyond transmission studies tied specifically to IRPs or renewables development, experts also pointed to examples of policies requiring a holistic study of transmission needs in a state (including to access generation from outside the state) to support economic development, improve reliability, and reduce power costs. They recommended using such studies to improve regional planning processes. For example, in 2023, **Colorado** enacted a law directing the Colorado Electric Transmission Authority to study the need for expanded transmission capacity across the state, including the ability to build new lines, improve existing lines, and connect to organized wholesale markets.[29] The statute also requires the study to assess whether and how expanded transmission capacity could improve grid reliability, help the state achieve its emission reduction goals, meet future electricity needs, and reduce land-use impacts by using existing rights-of-way, co-locating multiple lines, reconductoring lines, and strategically siting new corridors. (*See PART II.B.2 for more on using existing rights-of-way, PART II.D.2 for more on transmission authorities, and PART II.E for more on reconductoring lines.*)

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25 220 ILCS 5/8-512(b)(1)-(2).
26 220 ILCS 5/8-512(b)(5).
27 CRS 40-2-126.
28 Maryland SB 781 (2023) (enacting Maryland Code, Public Utilities § 7–704.3).
29 CRS 40-42-109.

2. Encouraging the Evolution of Transmission Plan Assumptions and Selection Factors

With respect to how planning is conducted, experts suggested that states should adopt policies that emphasize using robust planning criteria, benefit analyses, and selection criteria, and that encourage states to participate meaningfully in regional planning processes. In particular, experts recommended that states consider policies to:

- *require utilities to plan transmission using the seven factors and seven benefits outlined in FERC Order No. 1920;*
- *require the use of best available data;*
- *require long-term planning timelines (20+ years);*
- *support the "right-sizing" of lines to plan capacity that will meet both the needs of today and the needs of the future; and*
- *move beyond focusing on selecting transmission projects simply because they have the lowest capital costs and instead consider a more comprehensive set of metrics that influence the ultimate cost of projects, such as savings from improving the technical efficacy of transmission lines (e.g., reducing line losses) and the benefits of limiting the exercise of eminent domain by siting in existing rights-of-way.*

3. Encouraging Greater Coordination on Planning

Given that much of the needed transmission infrastructure will touch multiple state agencies and utility territories, coordinated planning is crucial. The lack of alignment within and across states, however, has impeded progress and delayed necessary upgrades and infrastructure development.

a) Intrastate Coordination

Intrastate coordination policies should aim to streamline the various roles that different state agencies may have in informing transmission planning efforts. For example, experts pointed to the 2022 California Memorandum of Understanding between two state agencies, the California Public Utilities Commission (CPUC) and the California Energy Commission (CEC), and the regional planner, California Independent System Operator (CAISO). The Memorandum of Understanding, among other things, establishes collaborative efforts where:

- The CEC develops a ten-year electricity demand forecast, forming the basis for transmission and resource planning, and conducts long-term assessments to gauge the impacts of California's decarbonization goals and policies;

- The CPUC creates forward-looking resource portfolios;
- CAISO conducts transmission planning;
- The CPUC incorporates CAISO's assessment of transmission planning needs and the CEC's load forecasts and long-term statewide resource planning into its resource procurement and transmission planning processes;
- The CEC utilizes the CPUC's resource planning in its own planning; and
- CAISO considers and incorporates the scenarios and portfolios developed by the CPUC (with input from the CEC) into its transmission planning process [30]

As a result of this coordination, California can plan transmission with a better understanding of future energy demands, infrastructure requirements, and policy impacts, ensuring that transmission development strategies are effectively aligned with the state's clean energy goals and long-term reliability needs. Such intrastate coordination also helps to set the stage for better coordination with neighboring states.

b) Interstate Coordination

Policies that support interstate coordination are particularly important due to the interconnected nature of the transmission network. Some experts pointed to multi-state RTOs and ISOs as a ready forum for state authorities to engage in interstate coordination, especially as state authorities in these regions often participate in regional state committees. Experts noted, however, that the level of coordination varies among RTOs/ISOs, as does the comprehensiveness of planning. Experts further suggested that state policies should encourage state authorities to participate more extensively in the regional transmission planning processes regardless of whether there is an RTO/ISO.

Experts also pointed to the Carolinas Transmission Planning Collaborative (originally established in 2005) as an example of another potential model for interstate collaboration even though it was created through a utility agreement, not state policy.[31] The Carolinas Transmission Planning Collaborative aims to develop a coordinated transmission plan for the areas of **North and South Carolina** served by the Collaborative's participants (Duke Energy Carolinas, Duke Energy Progress, ElectriCities of North Carolina, and the North Carolina Electric Membership Corporation). The Collaborative also includes a Transmission Advisory Group, which allows interested stakeholders to offer advice and recommendations regarding the coordinated transmission plan.

30 Memorandum of Understanding between the California Public Utilities Commission (CPUC) and the California Energy Commission (CEC) and the California Independent System Operator (ISO) Regarding Transmission and Resource Planning and Implementation, 2022.
31 Carolinas Transmission Planning Collaborative.

In 2024, states in the Northeast and Mid-Atlantic established their own collaborative through a memorandum of understanding between **Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island,** and **Vermont**.[32] The Northeast States Collaborative on Interregional Transmission provides a framework for coordinating interregional transmission planning and development by sharing information, cooperating on infrastructure planning, establishing technical standards, and discussing strategies for engagement with key stakeholders such as DOE, FERC, and ISOs/RTOs. The Collaborative will also facilitate the sharing of technical expertise, staff, and necessary resources among states.

B. SITING AND PERMITTING

With some exceptions,[33] the current Federal Power Act leaves authority over siting and permitting transmission lines to states. Some states have declined to exercise their authority, leaving permitting decisions to local governments. Among states that have exercised this authority, each has its own approach to transmission siting and permitting. In some states, transmission permitting authority and siting oversight lie with the state utility commission, while other states have created a state siting board or assigned responsibility to another agency to review such decisions. In addition, sister agencies, such as environmental or natural resources agencies, may have a role in authorizing transmission project permits. In some states, the lead agency serves as the coordinating entity, while in others, developers are responsible for executing such coordination.

States' siting and permitting processes, while varied, are often delayed by similar types of issues, such as bureaucratic delays and local opposition to projects. Experts emphasized that states must find ways to speed things up, while still addressing local concerns.

> Experts proposed four buckets of policies that could accelerate or otherwise improve siting and permitting processes:
>
> 1. Reducing duplications between federal and state permitting processes, regional planning and state processes, and neighboring states, and within a state.
> 2. Maximizing use of existing rights-of-way.

32 Memorandum of Understanding: Northeast States Collaborative on Interregional Transmission ("Collaborative"), 2024.

33 16 USC § 824p (FERC backstop siting authority); *see also Applications for Permits to Site Interstate Electric Transmission Facilities*, Order No. 1977, 187 FERC ¶ 61,069 (May 13, 2024). As this report was being finalized, Senators Manchin and Barrasso introduced the Energy Permitting Reform Act of 2024, proposing to streamline the federal siting requirements for qualifying transmission lines. S.4753 § 401 (2024).

3. Requiring early and collaborative engagement with and support for communities impacted by projects.
4. Recognizing and attaching value to the full suite of benefits that the state can receive from a strong regional and interregional transmission network within permitting analyses.

1. Streamlining Bureaucracy

Duplicative, mismatched, or conflicting processes among the different governmental agencies involved in siting and permitting can add years to a transmission project's timeline for review and approval. Experts suggested that states can expedite review by better coordinating and harmonizing such processes.

a) Harmonizing Federal and State Processes

Some projects, especially those sited in states in the West, may need to obtain both federal and state permits to move forward. Currently, in most states, the state and federal processes are entirely independent of one another, requiring developers to undergo each process separately. Each process can have its own criteria and may even require different forms of data reporting for similar criteria. Worse, in some cases, a change directed by a state or federal agency could trigger a whole new review of the application.

Experts noted that state policymakers can mitigate these redundancies by implementing policies that align and coordinate state and federal reviews. For example, experts noted that in **California**, the regulations for implementing the California Environmental Quality Act (CEQA) allow for joint review of projects subject to both CEQA and the federal National Environmental Policy Act (NEPA).[34] When an Environmental Impact Statement under NEPA is completed before the CEQA process, state or local agencies can largely use the NEPA document instead of preparing a separate Environmental Impact Report under CEQA.

Experts likewise mentioned **Nevada** as a state with good coordination of federal and state reviews for transmission projects. Although Nevada law requires any transmission project undergoing federal review to wait and apply for state permits only after the federal review is done, experts noted that the two-step process is intended to streamline reviews, as the law also requires the Public Utilities Commission "to accept and incorporate the findings and conclusions" of federal environmental reviews and prohibits the Commission from conducting duplicative environmental reviews.[35]

34 Cal. Code Regs. Tit. 14, § 15220 et seq.
35 NRS 704.834, 704.870, and 704.877.

Experts cited **Oregon** as an example of a state on the other end of the spectrum. Oregon law establishes timelines for permitting decisions and directs the Energy Facility Siting Council to avoid duplication, ensure consistency, and align timeframes whenever feasible for any projects also undergoing NEPA review.[36] However, experts indicated that, in practice, projects in Oregon encounter lengthy permitting review timelines due to the state process starting only after the federal review is complete. In 2024, some Oregon legislators proposed reforms somewhat similar to California, introducing a bill to exempt transmission projects that are sited wholly on federal land and undergoing NEPA review from additional review by the Siting Council, but the bill failed to pass the Oregon Senate.[37]

b) Coordinating Regional Planning and State Permitting

Many states require the transmission-developing entity to obtain a certificate of public convenience and necessity (CPCN) prior to commencing construction. Generally, to grant a CPCN, the state will consider whether the project is in the public interest and meets the state's criteria for respecting environmental, cultural, and other resources. The processes that a state uses to evaluate a project's necessity can have a significant impact on the timeline of transmission projects as streamlined processes will help facilitate transmission development.

For example, experts explained that in 2023, **California** passed legislation that required the CPUC to establish a rebuttable presumption in favor of the need for a CAISO-approved transmission project (if certain conditions are met).[38] Prior to the adoption of this policy, the CPUC's review of the need for transmission projects awarded out of the CAISO planning process took several years and was duplicative of CAISO's process. Similarly, experts encouraged states to adopt permitting policies that accord deference to a regional plan's finding of need if the project in question was identified through a FERC-compliant regional planning process and selected for regional cost allocation.

c) Coordinating Interstate Processes

When transmission lines span more than one state, the project developers may need to obtain permits from each state that the project passes through, which can each have different information and data requirements and different decisional timelines. Experts noted that states can accelerate project deployment by reducing their share of the administrative burden for at least some interstate projects. For example, experts mentioned that **Minnesota's** 2024 energy infrastructure permitting reform legislation

36 ORS 469.370(13).
37 Oregon HB 4090 (2024).
38 CA Pub. Util. Code § 1001.1 (2023).

includes, among other things, an exemption from certificate of need requirements for any cross-state transmission line with a capacity of 100 kV or more if 10 miles or less of its length is within Minnesota (as well as any line with a capacity of 300 kV or more if less than 1 mile of its length is in Minnesota).[39]

Experts also indicated that states could enter into collaborations (through memorandums of understanding or other formal[40] or informal processes) that allow for streamlined reviews by:

- *aligning, as much as possible, the criteria under which a permit will be issued;*
- *offering a one-stop shop to make project filings and to monitor progress on reviews and approvals, which also ensures that states all have access to the same data and analyses on a project and that developers and other interested parties have transparency on the status of project review;*
- *coordinating review and timing of the project filings; and*
- *issuing joint orders.*

d) Reducing Intrastate Inefficiencies

Even within a state, permitting jurisdiction can be fragmented; both state and local governments, and sometimes multiple state agencies, may have authority over siting and permitting. In states where local governments control the siting decisions, one local government's opposition can upend the development of a line that is hundreds of miles long. Experts highlighted state policies that streamline state processes or that expedite the local review process by preempting local authority or by offering additional support to local governments.

Streamlining State Processes: Experts highlighted the importance of reducing fragmentation of siting and permitting authority at the state level. For example, experts pointed to **New York**'s RAPID Act (2024), which shifted and consolidated the state's transmission siting authority into a one-stop shop in the new Office of Renewable Energy Siting and Electric Transmission (ORES) at the Department of Public Service.[41] Among other things, the RAPID Act requires ORES, in consultation with other state agencies, to establish a set of uniform siting, design, construction, and operation standards for major transmission facilities, and the Act sets deadline for ORES to determine an application is complete and issue draft permit conditions for public

39 Minn. SF 4942 (Chapter 126) Article 8, Section 1 (2024) (amending Minn. Stat. §§ 216B.2421, 216B.243).

40 *See, e.g.* 16 USC § 824p(i) (authorizing three or more contiguous States to enter an interstate compact and establish a regional siting agency to facilitate siting of transmission lines).

41 NY Assembly Bill A8808–A, Part O (adding Section 3-C to New York Consolidated Laws, Public Service Chapter 48, Article 8).

comment and issue a final decision.[42]

Preempting Local Authority: Several states have taken action to limit the potential for local opposition to derail projects. **New Jersey**, for example, enacted an offshore wind law in 2022 that, among other things, provides developers of offshore wind-related transmission facilities approved by the state Board of Public Utilities with the right to build on or under any local jurisdiction's streets, thoroughfares, and rights-of-way — and if any such facility is unable to obtain an easement, right-of-way, or other needed property interest in any other real property owned by a local government, the Board of Public Utilities will have the authority to approve it.[43]

Similarly, experts mentioned that **Massachusetts** Executive Order 620 established a Commission on Energy Infrastructure Siting and Permitting to advise the Governor on siting and permitting reform to accelerate deployment of clean energy infrastructure, including transmission.[44] The Commission issued recommendations in 2024 that included a permitting process for both large and small transmission projects that would consolidate all necessary local, regional, and state approvals.[45] Legislation to implement these and other permitting reforms failed to make it out of conference committee during the Massachusetts legislature's 2024 session.[46]

Experts acknowledged that preempting local authority can be controversial, and they recommended ensuring avenues remain open for local governments to engage and have their concerns heard. For example, although local governments are prohibited under **New York** law from requiring separate approvals, permits, or certificates for transmission facilities,[47] ORES must provide opportunity for the local governments in which proposed transmission facilities are to be located to "indicat[e] whether the proposed facility is designed to be sited, constructed and operated in compliance with applicable local laws and regulations, if any, concerning the environment, or public health and safety."[48]

Offering Additional Support to Local Authorities: Experts also indicated that some state policies use a softer method aimed at influencing local governments to streamline their processes. For example, in May 2024, **Colorado** enacted a law requiring the Colorado Energy Office, in cooperation with other state departments, to develop a repository of codes and ordinances that support transmission facilities for the purpose

42 *Id.*
43 NJ Rev Stat § 48:3-87.1.
44 Mass. Exec. Order No. 620 (2023).
45 Commonwealth of Massachusetts, "Recommendations to Governor Maura Healey on Clean Energy Infrastructure Siting and Permitting Reform," Mar. 29, 2024.
46 *See, e.g.,* Mass. H.B. 4884 § 51 (2024).
47 NY Consolidated Laws Public Service Chapter 48, Article 8, § 144.
48 NY Consolidated Laws, Pub. Service Chapter 48, Article 8, § 143 (added by the RAPID ACT, NY Assembly Bill A8808–A, Part O).

of "providing conceptual frameworks that local governments and Tribal governments may consider and adapt to suit local circumstances."[49] The Colorado Energy Office was also directed to conduct an evaluation of local government transmission siting processes and report its results to the General Assembly.[50]

2. Leveraging Existing Rights-of-Way

Transmission lines that are sited on greenspace or that require the developer to site on private land can be quite contentious, raising concerns about environmental and cultural impacts, private land rights, and just compensation; in turn, these concerns can lead to protracted permitting processes. Conversely, siting transmission projects on existing rights-of-way — such as along highways or railroad tracks — can reduce permitting requirements and expedite environmental reviews, as the land has already been disturbed and, in the case of highways, designated for use for public purposes. Siting in existing rights-of-way may also face less local opposition because communities are likely already accustomed to the existing infrastructure in those corridors.

Experts encouraged states to adopt policies that facilitate the siting of transmission in existing rights-of-way — recognizing, however, that such policies should be crafted and implemented in a manner that is respectful of communities that already host infrastructure on those rights-of-way and that ensures those communities have an opportunity to meaningfully engage with projects considered for co-location. Experts noted that particular attention should be paid when siting in highway rights-of-way, as historical practices in siting highways divided some communities, largely impacting minority and marginalized communities.

While federal law no longer prohibits the installation of electricity infrastructure next to highways, and in fact now encourages such use, many states still have policies on the books that make such siting difficult. Experts suggested that states should look to adopt policies that make clear that projects should prioritize siting in existing rights-of-way when selecting corridors. **Wisconsin** law, for example, establishes an explicit prioritization of corridors for siting new transmission, in the following order: existing utility corridors, highway and railroad corridors, recreational trails (if the facilities can be constructed underground), and new corridors.[51] Experts likewise pointed to **Minnesota**, which adopted legislation in 2024 authorizing high-voltage transmission to be constructed along highways or roadways.[52]

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49 CO Senate Bill 24-212 (2024) (amending Colorado Revised Statues, Title 29, Article 20).
50 *Id.*
51 Wis. Stat. § 1.12(6).
52 HF 5247, (Chapter 127), Article 3, Section 17 et seq. (2024) (amending Minn. Stat. § 161.45, subd. 4).

3. Requiring Early and Collaborative Engagement With and Support for Communities Impacted by Projects

Local impacts of transmission development (and other major infrastructure projects) can be a major roadblock to siting and permitting, especially when it results in opposition from local communities. To help offset the impacts of development and reduce potential opposition, experts encouraged the adoption of policies that require early and collaborative engagement with communities and that offer direct benefits for the communities that are hosting projects.[53]

For example, **Wisconsin** law provides financial compensation to the towns or municipalities that host transmission projects.[54] Transmission owners pay an annual impact fee that is equivalent to 0.3% of the project cost in addition to a one-time environmental impact fee that is 5.0% of the project cost.[55] The state then distributes half of this money among the counties and the other half among the municipalities that host the transmission line.

4. Considering the Broader Benefits of Regional Transmission in Siting Processes

Experts highlighted the importance of having state policies recognize the full suite of benefits that the state can receive from a strong regional and interregional transmission network. Relatedly, it is important that the broad benefits of transmission be well defined in the planning process and that state policymakers are educated on how those benefits manifest.

For example, experts pointed to a 2024 **Louisiana** law that limits the power to exercise eminent domain to transmission projects that demonstrate that most of the electricity being transmitted over that project will be delivered to end users in Louisiana.[56] Quite reasonably, states are interested in ensuring that their citizens benefit from any infrastructure they are asked to fund and host. Due to the interconnected and multifaceted nature of transmission, however, the benefits to a state extend beyond just the delivery of power. Restrictive criteria can result in blocking lines that are needed to deliver other benefits that transmission can bring to a state.

53 For more information on these issues, please see ACEG's soon-to-be-released report on best practices for community engagement.
54 Wisc. Stat. § 196.491(3)(gm) and (3g).
55 Wisc. Stat. § 19.969.
56 Louisiana Rev. Stat. § 19:2(7) (amended by SB108 (2024)).

C. COSTS AND FINANCING

Transmission — particularly the long, high-capacity transmission lines needed to strengthen the electric network — involves major capital investment. The costs of these investments all eventually flow down to utility ratepayers. (As discussed in Part I, ratepayers also ultimately bear the costs of the impacts that come from failing to expand and modernize the transmission system.) Because all roads lead to the ratepayer, it is important that transmission investments are cost-effective and that the costs imposed on ratepayers be just and reasonable. It is also important to figure out how to allocate those costs and, where possible, to reduce them.

> Experts identified two key types of state policies related to transmission costs:
>
> 1. Engaging proactively and productively in regional and interregional cost allocation discussions to develop methodologies that consider the full suite of transmission benefits so project costs are shared equitably.
> 2. Providing public funding, or leveraging public or public-private financing opportunities, to reduce the total project costs and, accordingly, the costs passed onto ratepayers.

1. Engaging on Interstate Cost Allocation and Transmission Benefits

Federal law applies the principle of "cost causation" — a bedrock principle of energy regulation — to mean that utility providers must allocate transmission costs in a way that is "roughly commensurate" with the benefits received.[57] Few states/customers are willing to raise their hand to take on greater cost obligations if they do not believe they benefit from a transmission line or if they believe it was spurred by another state's policies or objectives that they did not participate in forming or with which they disagree. There is also a perverse incentive to be a free-rider and benefit from a transmission project without having to pay for it. The allocation of cost responsibilities can become quite contentious, and the contentiousness is only exacerbated when the criteria used to determine benefits are not clear or are restricted to a subset of the benefits that transmission provides.

Since the largest cost allocation challenge is when a project crosses state borders, a single state policy will likely not overcome this hurdle. Still, while it is the responsibility of transmission providers to propose cost allocation formulas to FERC, state input

57 *Preventing Undue Discrimination & Preference in Transmission Serv.*, Order No. 890, 118 FERC ¶ 61,119, PP 622, 637, 72 Fed. Reg. 12,226, *order on reh'g*, Order No. 890-A, 121 FERC ¶ 61,297 (2007), *order on reh'g*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g*, Order No. 890-C, 126 FERC ¶ 61,228, *order on clarification*, Order No. 890-D, 129 FERC ¶ 61,126 (2009); *Transmission Planning & Cost Allocation by Transmission Owning & Operating Pub. Utils.*, Order No. 1000, 76 Fed. Reg. 49842 (Aug. 11, 2011), 136 FERC ¶ 61,051 (2011), *order on reh'g*, Order No. 1000-A, 77 Fed. Reg. 32184 (May 31, 2012), 139 FERC ¶ 61,132, *order on reh'g and clarification*, Order No. 1000 -B, 141 FERC ¶ 61,044 (2012), *aff'd sub nom. S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41 (D.C. Cir. 2014); *see also Illinois Commerce Commission v. FERC*, 576 F.3d 470, 476 (7th Cir., 2009).

and support are critical in determining whether projects will move forward or will be stalled by disagreements over who will pay. Experts suggested that a set of principles or recommendations on cost allocation, agreed upon by a group of states, could be critical to developing interstate transmission (and could serve as the basis for state-level policies).

For example, experts noted that regional transmission expansion processes in the MISO North region are leading to development. They credit a 2010 letter from Midwest governors to MISO for jumpstarting MISO's interest in working proactively.[58] Conversely, experts noted that transmission expansion in the MISO South region is hindered by a lack of consensus among states on how costs should be allocated.

Experts emphasized that the importance of states engaging with each other on cost allocation, whether under direction of a state policy or through voluntary coordination, is even greater in the wake of FERC Order No. 1920. Examples of such engagement could include:

- *In RTO/ISO regions, working within regional state committees (e.g., Organization of the PJM States, Organization of MISO States);*
- *In all regions, procuring an independent facilitator to help states, utilities, and other interested parties develop consensus around cost allocation principles that recognize the full suite of benefits that transmission provides; and*
- *In all regions, increasing common understanding of cost allocation issues and options by bringing in third-party technical experts to share information.*

In addition, as mentioned in the siting and permitting CPCN discussion, experts also agreed that policies that specifically include consideration of regional benefits, as opposed to consideration primarily of in-state benefits, are much more supportive and reflective of the value of regional transmission expansion and modernization.

58 Midwest Governors Association, Letter to Mr. John Bear, Oct. 18, 2010 (stating that "A well-designed regional transmission system is essential to realizing the full potential of the new energy economy, will help our states grow jobs and also will help to meet the MGA's renewable energy goals in a well planned and cost effective manner."); *see also* Whitmer, G., Pritzker, J.B., Walz, T., Evers, T,"RE: Support for MISO's Long-Range Transmission Planning Effort to Cost-Effectively Maintain System Reliability in the Face of a Changing Climate," (2021).

2. Providing Public Funding and Financing for Transmission Projects

Apart from allocating the costs of transmission, the high capital cost of transmission infrastructure presents its own challenge. Experts noted that state policies could address this barrier by funding projects directly or leveraging public or public-private financing opportunities.

Experts pointed, for example, to **California**, which established the Eligible Energy Resource Central Procurement Fund in 2023.[59] Under this framework, the Department of Water Resources, if requested by the Public Utilities Commission, can use resources in the fund to cover the costs of energy resources and transmission centrally procured by the state.

Experts also pointed to the role that state transmission authorities can play in providing financing to develop transmission projects. **New Mexico**, for example, as part of the establishment of the Renewable Energy Transmission Authority, empowered the Authority to provide financing for transmission projects it deems necessary.[60] Similarly, in **North Dakota**, the North Dakota Transmission Authority can provide bond financing for transmission projects to foster in-state energy production.[61] (*See PART II.D.2 below, for more on transmission authorities.*)

D. STRENGTHENING THE ABILITY OF STATE AGENCIES TO ENGAGE IN TRANSMISSION PLANNING AND DEVELOPMENT

State engagement in and oversight of transmission planning and development are frequently hindered by bureaucracy and inadequate clarity on roles and responsibilities, raising barriers to participate in regional planning processes and causing delays in processing transmission proposals.

> Experts raised three categories of policies that can help state agencies to better engage with transmission planning and to process transmission proposals more quickly:
>
> 1. Enhancing staffing and technical resources available to state agencies.
> 2. Coordinate transmission-related education across and engagement between state agencies and with other interested parties
> 3. Consolidating transmission support and decision-making in a state transmission authority.

59 CA Water Code § 80830.
60 NM Statutes §§ 62-16A-2 et seq.
61 ND Century Code Chapter 17 § 05.

1. Enhancing Resources Available to State Agencies

In most states, the entities assigned to engage with transmission planning and development (e.g., utility commissions, energy offices, siting boards) are often stretched thin, balancing a broad range of regulatory responsibilities. They frequently do not have the budgets to support the specialized expertise, training, staff, and resources necessary to fully oversee the maintenance and development of transmission systems, much less to meaningfully engage in the interstate planning processes that are critical to the creation of strong transmission systems. These constraints are further compounded by staff turnover and loss of expertise, especially as transmission projects can arise less frequently than other issues these entities regularly face.

Experts suggested that a basic but essential way to address these challenges is for states to enhance the effectiveness of their state utility commissions (and/or other relevant entities) by strategically allocating additional resources and budget. With expanded budgets, they could hire more transmission experts to help inform decision-making processes and engage more effectively in planning processes at FERC and at the regional level. Some experts noted, however, that there is a generalized shortage of transmission planning engineers in the United States and that longer-term workforce development programs may be needed to support improved state engagement in transmission development. (*Workforce development is discussed in Section F*).

2. Coordinating Transmission-Related Education Between State Agencies and With Other Interested Parties

These issues can also be managed through policies that call for coordinated education and engagement on transmission issues. As an example, experts pointed to **Nevada**'s Regional Transmission Coordination Task Force that was created through legislation in 2021 and charged with advising the governor and legislature on, among other things, the potential costs and benefits of forming or joining an RTO, policies to site transmission facilities needed to achieve Nevada's clean energy and economic development goals, and potential areas within Nevada where "growth in demand for electricity or growth in renewable energy generation would be accommodated by additional transmission or regional market opportunities."[62] The Task Force includes, among other entities, representatives from the Office of Energy, the Office of Economic Development, the Department of Native American Affairs, and the Public Utilities Commission, as well as representatives from incumbent utilities, transmission line developers, public power, geothermal and large-scale solar energy industries, data center and gaming businesses, the mining industry, and labor and environmental organizations.

62 NRS 704.79881 et seq. More information on the Regional Transmission Coordination Task Force can be found on its website.

In a similar vein, in **New York**, the Public Service Commission, using its regulatory authority, authorized utilities within the state and the Long Island Power Authority to conduct a Coordinated Grid Planning Process to coordinate on long-term transmission planning, including with respect to data collection processes, modeling, system studies, and solutions development. In so doing, the Commission also established an Energy Policy Planning Advisory Council (EPPAC) comprised of, among other entities, representatives of the NYISO, the New York State Energy Research and Development Authority (NYSERDA), the Department of Public Service, generation and storage associations, the New York Power Authority, the Office of Renewable Energy Siting, the Utility Intervention Unit of the New York Department of State, the City of New York, and environmental justice organizations. The EPPAC has a role in establishing the assumptions and developing the scenarios that will be used in the planning process.[63]

Experts also referenced **Delaware**, where a state legislator has convened a voluntary standing working group of the state agencies and other interested parties that impact energy issues and decision-making in the state. This Energy Stakeholders Group meets every other week to develop a common high-level understanding of energy issues of importance.

3. Consolidating Transmission Support and Decision-Making In a State Transmission Authority

Another way to manage these issues is through the development of a dedicated state transmission authority that can serve as a centralized body to address many of the issues discussed throughout this report, including enhancing planning strategies, streamlining siting and permitting, and providing funding and/or financing to transmission projects. A well-structured transmission authority can also coordinate with various stakeholders and develop comprehensive long-term transmission development strategies that align with a state's energy goals.

Examples of transmission authorities that experts indicated have been successful in advancing transmission development include the **Colorado** Electric Transmission Authority (CETA),[64] the **New Mexico** Renewable Energy Transmission Authority (RETA),[65] and the **North Dakota** Transmission Authority (NDTA).[66] While their specific functions and powers vary to some degree, there are notable similarities regarding these authorities' central roles, including transmission planning, providing financing for projects, and inter- and intra-state coordination. Some authorities, including in

63 NY PSC, Case 20-E-0197, *Proceeding on Motion of the Commission to Implement Transmission Planning Pursuant to the Accelerated Renewable Energy Growth and Community Benefit Act*, Order Approving a Coordinated Grid Planning Process, issued Aug. 17, 2023.

64 The CETA was created in 2021 through Senate Bill 21-072 (CRS 40-42-101 et seq.).

65 The New Mexico RETA was created in 2007 through House Bill 188 (NM Statutes §§ 62-16A-2 et seq.).

66 The NDTA was created in 2005 (ND Century Code Chapter 17 § 05).

Colorado and New Mexico, also have the power of eminent domain to acquire property or rights-of-way for transmission projects.

Other states have also been exploring the creation of a state transmission authority. For example, experts noted that **Maryland** legislators introduced a bill in 2024 to create a transmission authority.[67] Although the bill was ultimately withdrawn by its sponsor, it is still notable in its thinking on how a transmission authority would function within a large RTO footprint in a deregulated state. The proposed Maryland authority was designed to research, evaluate, and identify critical issues in electricity transmission — and to work alongside PJM to facilitate effective planning, siting, and permitting of transmission projects.

E. TRANSMISSION MODERNIZATION

While transmission expansion is critical, it is also imperative to leverage all available technologies to unlock the full capacity of existing transmission infrastructure. There are two main categories of technologies used for transmission modernization: grid-enhancing technologies (GETs) and high-performance conductors, together known as advanced transmission technologies or ATTs.

Advanced transmission technologies offer several advantages compared to one-to-one replacements of existing systems or plans to build only new transmission, including:

- The technologies can be integrated into existing transmission facilities to unlock additional capacity and improve network performance, at lower levels of capital expenditures than building new transmission.
- The technologies have shorter deployment timelines than new transmission.
- The technologies can be installed on existing rights-of-way (reducing the need to obtain new greenspace) and in some cases can be installed remotely without the need for onsite crews.
- The technologies offer technical efficiency and reliability benefits that allow operators to safely maximize the power transferred over a line. High-performance conductors offer additional capacity that can be used to help relieve locational constraints to reduce congestion and potentially reduce locational resource adequacy requirements. High-performance conductors also reduce or eliminate thermal sag, thereby reducing the risk of sparking a wildfire. GETs provide access to new data that can deliver real-time insights and unlock more dynamic capabilities of transmission lines.

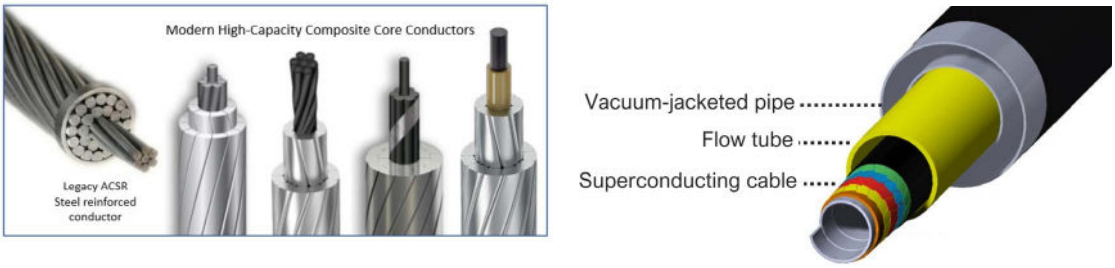
67 MD SB 920 (2024).

MINI-EXPLAINER | ADVANCED TRANSMISSION TECHNOLOGIES

Grid-enhancing technology is a general term that refers to technologies that "maximize the transmission of electricity across the existing system."[a] These include:

- **Dynamic line ratings (DLR)**, which adjust the capacity of a line based on weather conditions. Lines are traditionally operated at a static rating to ensure safe operations regardless of the ambient air temperature. Dynamic line rating technologies allow operators to adjust capacity flows in real-time and maximize the capabilities of lines, which can deliver 50% or more energy than labeled limits in cold or windy conditions as the risk of overheating is lower than on hot days;
- **Advanced power flow control**, which uses hardware to reroute electricity based on congestion and maximize the full capacity of the network; and
- **Topology optimization**, which uses software that evaluates the best use of the grid based on generation, demand, and the status of grid infrastructure and reroutes power accordingly.[b]

FIGURE 7. **Examples of Traditional Conductor (Box, Left), Advanced Composite Core Conductor (Box, Right), and Superconductor (Right)**



Source: CTC Global (traditional conductor and advanced composite core conductor) and VEIR (superconductor)

High-performance conductors are present and future transmission line technologies with exponentially greater power flow capacities compared to conventional transmission line technologies over equivalent voltage lines. Traditional conductors have a core of cylindrical steel strands to provide strength to the line, surrounded by cylindrical aluminum strands that conduct electricity (*see Figure 7*). Due to the configuration of circular shapes that are bundled together, there are open areas that limit the overall carrying capacity of the line. Moreover, under high heat conditions, the steel core will start to sag, increasing wildfire risk and limiting how much power can be carried safely. High-performance conductors — which can be used in new transmission

projects or in reconductoring projects (i.e., installed on existing transmission infrastructure that is in good condition) — offer significant potential for improvement. For example:

- **Composite core conductors** have a composite core that is lighter and stronger than conventional steel, surrounded by trapezoidal-shaped annealed aluminum wires that conduct electricity (*see Figure 7*). Compared to traditional conductors, these differences effectively double the carrying capacity, increase efficiency, and result in less sag in hot weather conditions (allowing for more power to be carried safely).[c]
- **Superconductors** "use a class of metallic compounds that exhibit negligible resistance when cooled using liquid nitrogen, enabling very low losses and high power-flow capacities"[d] (*see Figure 7*). Compared to traditional conductors, superconductors offer five times the carrying capacity of traditional lines, are 50% more energy efficient, and do not sag in high heat conditions.

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a DOE, "Grid-Enhancing Technologies: A Case Study of Ratepayer Impact," 2022.
b Watt Coalition, "What are Grid Enhancing Technologies?" last accessed Jul. 2024.
c Breakthrough Energy, "Both/And—We Should Boost Existing Transmission Today and Build New Lines for Tomorrow," Apr. 9, 2024.
d AMP and WATT Coalition, "Unlocking the Grid with Advanced Transmission Technologies," 2024.

Even though GETs and high-performance conductors offer measurable customer benefits, there is still some reluctance to install these technologies. Experts flagged a few reasons for this, including the following:

- Some economic analyses of utility investment options tend to examine only capital costs, and high-performance conductors can be more expensive than their traditional counterparts on a per-mile basis. However, these analyses do not account for the additional savings that could result from integrating modernized technologies, including energy efficiencies, avoided investments to otherwise increase transmission capacity, and lower congestion charges from operational efficiencies.
- The utility industry generally tends to be risk averse and slow to change. For example, the technology for the traditional aluminum conductor steel-reinforced (ACSR) cable was invented in the early 1900s. Moreover, traditionally, the grid is operated on a "static" basis, based on a set of safe operating conditions. The unlocking of dynamic capabilities of the grid through GETs may require a complete cultural shift, operator retraining, and the development of new operational procedures.

- Because many planning processes react to immediate or near-term reliability concerns, rather than looking at the longer time horizon, projects that propose high-performance conductors may be accused of "gold-plating" (i.e., spending more than necessary to reasonably serve customers) to increase revenue.
- Traditional utility incentives, which offer a return on capital investment projects but not on non-capital projects that improve operations or maintenance, do not incentivize a utility to proactively implement modernized transmission technologies.

Experts highlighted three categories of state policies to encourage deployment of advanced transmission technologies:

1. Directing utilities and relevant state authorities to study GETs and high-performance conductors in state-level planning or permitting processes.
2. Providing financial incentives or reducing financial risk for investments in transmission modernization where such action is legally sufficient and sustainable.
3. Creating an environment that encourages the implementation of GETs and high-performance conductors.

TRANSMISSION MODERNIZATION POLICY LANGUAGE CONSIDERATION

Experts caution that because not all GETs and high-performance conductors are created equal, it is important that any policy aimed at advancing these technologies include defined performance criteria to ensure that the desired grid benefits materialize and that project developers cannot game the system. Experts gave the example of a 2023 law in **Montana** that includes the following efficiency performance criteria in its definition of advanced conductor:

> an overhead electricity conductor installed in a transmission or distribution project that has a direct current electrical resistance at least 10% lower than existing conductors of a similar diameter on the system.[a]

The law also outlined technical criteria for how to measure the efficiency savings, stating that "cost-effectiveness criteria … must be based on established direct current resistance at standard pressure and a temperature of 20 degrees Celsius."

a Montana Code § 69-3-714.

1. Issuing Directives to Study GETs and High-Performance Conductors in State-Level Planning or Permitting Processes

a) Utility Studies

Experts noted that some states have passed, or are considering, policies to accelerate deployment of modernization technologies by requiring utilities to evaluate their ability to increase capacity and the associated cost effectiveness. For example, experts pointed to **Virginia**, where legislation was passed and enacted in April 2024 requiring utilities to include in their IRP filings "a comprehensive assessment of the potential application" of advanced transmission technologies and to provide a detailed explanation if such technologies are not included in the IRP.[68] Additionally, **California**, as of mid-July 2024, has legislation pending that would require utilities to conduct every two years a study on the feasibility of deploying GETs and every four years a study on which transmission lines can be reconductored using high-performance conductors.[69] It also requires that the utilities submit the studies to CAISO and make the studies publicly available.

Experts also noted that states could require consideration of advanced transmission technologies through their state CPCN processes as a condition of granting the permit.

b) Other Studies

Experts noted that in lieu of tasking utilities with studying advanced transmission technologies, some state policies assign this responsibility to themselves or, if they have the authority to do so, the transmission planners. For example, **Maine** passed legislation in 2024 requiring the Public Utilities Commission to conduct a review every five years of available grid-enhancing technologies "that could be implemented by a large investor-owned transmission and distribution utility to reduce or defer the need for investment in grid infrastructure in the State."[70] **California** has pending legislation that would require CAISO to provide reports to the Legislature detailing grid-enhancing technology deployments and associated cost and efficiency savings.[71]

2. Providing Financial Incentives or Reducing Financial Risk for Transmission Modernization Investments

In discussing the importance of modernization, several experts identified financial incentive policies as a positive development, explaining that utilities often respond

68 VA HB 862 (enacted April 5, 2024) (amending VA Code §§ 56-597 and 56-599).
69 California Senate Bill 1006 (2024).
70 Maine Senate Paper 257, Section 1 (enacting 35-A MRSA §3148) (2024).
71 California Assembly Bill 2779 (2024).

more positively to "carrots" than "sticks." However, several experts also expressed concern that state policies that provide financial incentives or authorize cost recovery for advanced transmission technologies could face litigation risk if they encroach, or are perceived as encroaching, on FERC's jurisdiction to set the rates, terms, and conditions for transmission. Some of the same experts also explained that because the financial incentives that are offered to utilities are then incorporated into the utility's rates and recovered from ratepayers, such incentives may also generate concerns about the total impact on affordability. As such, in developing financial-related policies, it is important to conduct a legal review of the policy from the lens of federal-state jurisdiction and to align the incentive with customer benefits and (if measurable) cost savings that would result from installing the modernized technologies.

a) Incentivizing ATTs through a Return on Equity Bump

Several experts raised **Montana**'s 2023 legislation, which allows the Public Service Commission to authorize "cost-effectiveness criteria for advanced conductor projects that may be placed into a utility's rate base", essentially allowing for a bump in a utility's return on equity if it includes qualifying advanced conductor technology in its transmission or distribution project.[72] The structure of this policy was based on Montana's existing demand-side program, which offers utilities a return on equity adder for realizing efficiency savings.

b) Incentivizing ATTs through Performance Incentive Mechanisms

Experts also mentioned performance incentive mechanisms, which ultimately tend to translate to return on equity adders, although the mechanism for calculating such an adder may be different than a direct return on equity bump. For example, there was a bill in the **New York** legislature in 2024 (which had some success but did not make it to the governor) that would have allowed a utility proposing capital improvements or additions to the transmission system to conduct a cost-effectiveness analysis of grid-enhancing technologies and advanced reconductors.[73] If the utility found that the modernized technologies, alone or in combination with other capital investments, were more cost-effective than traditional technologies at achieving the utility's transmission goals, the utility could request a performance incentive mechanism for deploying the proposed GETs or high-performance conductors.

c) Incentivizing ATTs by Authorizing Cost Recovery

While states generally allow cost recovery for infrastructure investments, some state utility commissions may be hesitant to direct their utilities to incorporate GETs and

72 Montana Code § 69-3-714.
73 NY SB 7868 / AB 9105A (2024).

high-performance conductors into their capital improvement plans and/or to allow cost recovery for GETs and high-performance conductor projects without express authorization and encouragement from their legislatures.

Experts pointed to a few states that have issued policies making it explicit that their utilities should include investment in advanced transmission technologies as part of their resource or capital investment plans, and that any such technologies that are cost-effective are eligible for cost recovery. For example, **Minnesota** passed legislation in May 2024 that directs any entity that owns more than 750 miles of transmission lines in the state to submit every two years a technical and cost-effectiveness evaluation of grid-enhancing technologies that can be used to solve certain grid concerns.[74] Specifically, the transmission owners must:

- identify areas of congestion over the past three years and projected congestion for the upcoming five years;
- project the increased cost to ratepayers due to congestion;
- estimate the feasibility, cost, and cost-effectiveness of installing GETs to address congestion; and
- propose an implementation plan to install GETs at congestion points.

The policy explicitly authorizes the Minnesota commission to approve cost recovery, including a rate of return, on "any prudent and reasonable investments made or expenses incurred" in administering and implementing the GETs implementation plan.

Utah similarly considered (ultimately unsuccessful) legislation in 2024 that would have directed utilities proposing additions to or expansion of the transmission system to include in such proposals an analysis of the cost-effectiveness of deploying GETs to meet electric system needs; the bill also would have authorized the Public Service Commission to approve cost recovery if it deemed the deployment of the identified advanced technologies to be cost-effective.[75]

3. Creating an Environment Encouraging the Integration of GETs and High-Performance Conductors

Experts identified a set of policies that would facilitate or indirectly encourage the integration of advanced transmission technologies. **California** has been particularly active in this regard. For example, it has pending legislation that would exempt utilities from permitting requirements for advanced reconductoring and instead only require

74 Minnesota SF 4942 (Chapter 126) Article 6, § 52 (2024)
75 Utah Senate Bill 191 (2024).

utilities to notify the California Public Utilities Commission through the more informal process of filing an advice letter.[76]

California also has pending legislation that recognizes that some advanced transmission technologies have lower wildfire risk than traditional transmission.[77] For example, as noted earlier, high-performance conductors sag less than their traditional counterparts during high-temperature weather. Experts noted that policies setting technical standards for wildfire prevention could establish levels that would limit consideration of traditional transmission lines and instead favor the installation of modernized technologies.

F. CREATING AN ECOSYSTEM THAT SUPPORTS ROBUST TRANSMISSION PLANNING AND COST-EFFECTIVE TRANSMISSION DEVELOPMENT

In addition to policies that have a direct impact on transmission expansion and modernization, experts noted that there are policies that can indirectly support effective transmission development by creating the conditions, processes, and capacity needed to foster a robust evaluation of transmission solutions and the development of beneficial projects.

> Experts highlighted three categories of broader state policies that could help advance transmission modernization and expansion:
>
> 1. Addressing other state policies, such as economic development and clean energy policies, with cost-effective solutions such as more robust transmission planning.
> 2. Reforming regional and state processes to promote transparency and meaningful engagement.
> 3. Enhancing workforce capacity.

1. Addressing Other State Policies, Such As Economic Development And Clean Energy Policies, With Cost-Effective Solutions Such as More Robust Transmission Planning

There are a range of state policies that require robust and thoughtful energy deployment, which, in turn, necessitates more comprehensive transmission planning, streamlined permitting, and equitable cost allocation. For example, policies to attract industries with heavy electricity loads (e.g., data centers), to promote beneficial

76 California Assembly Bill 3246 (2024).
77 California Senate Bill 1006 (2024).

electrification, and to onshore manufacturing can lead to an increase in customer electricity demand that requires improved transmission planning and development to identify the most cost-effective long-term solutions with the least impact on customers. Well-planned transmission must be part of any long-term energy solution. Experts noted, for instance, that 2024 legislation enacted in **Maine** required the Efficiency Maine Trust to develop a three-year beneficial electrification plan for end uses of energy and directed the Trust to seek input from transmission utilities and to consider integrating with and informing the commission's consideration of grid planning priorities.[78] Experts also pointed to state policies that mandate large expansions of clean energy generation, such as renewable portfolio standards and clean energy standards, as underpinning the need to better plan the transmission network to ensure there is sufficient capacity available to facilitate interconnection of clean energy generation to the grid.

2. Reforming State Regulatory and Regional Planning Processes

There are regional and state processes focused on issues much broader than just transmission that, if enhanced, could improve the planning, development, and management of transmission. For example, some experts highlighted the potential for states to adopt policies that increase transparency around regional planning processes. In 2024, legislators in **Illinois**,[79] **Maryland**,[80] **Virginia**,[81] and **West Virginia**[82] proposed bills to require their utilities to report publicly their votes at PJM. Supporters of these policies explained that these requirements would improve ISO/RTO governance and help states and interested parties create pressure for better and more comprehensive decision-making on transmission. Others disagree that such modifications are needed, explaining that current PJM rules that aggregate voting at lower committee levels allow for stakeholders to engage in consensus building exercises. They also expressed a further concern that if such rules do not apply across all states and all members that it would be discriminatory and could have a chilling effect on participation.

Experts also noted that it would be helpful for regional planners, both in RTO and non-RTO regions, to be subject to broader information-sharing requirements, similar to the Sunshine Act and Freedom of Information Act requirements for federal, state, and local governments. This would allow stakeholders to better assess, among other things, how planning is conducted, including whether the best available data is being used, whether the most cost-effective solutions are being selected, and whether there is undue influence on the process.

78 Maine SP 257, Section 3 (amending 35-A MRSA §3803) (2024).
79 Illinois HB4747 (2024).
80 MD HB0505 (2024), cross-filed with SB0682.
81 Virginia HB 109 (2024).
82 West Virginia HB5101 (2024).

Within states, experts noted the wide range of ways states utilize IRPs and suggested that transmission development (and long-term energy planning in general) would be improved if there were more robust IRP processes — including formal reviews, public comment periods, discovery, expert testimony, and evidentiary hearings — before a state utility commission issues a final decision.

3. Enhancing Workforce Capacity

Experts flagged workforce adequacy as a necessary condition for energy infrastructure deployment, including transmission expansion and modernization. Workforce needs extend across the labor chain, from trained electricians and lineworkers who are provided enhanced training around modern transmission technologies, to planners who develop the needs and solutions assessments, to community engagement specialists who can facilitate meaningful and informed conversations between impacted landowners and developers, to attorneys, economists, accountants, policy experts, and others who can review and assess whether projects are cost-effective and the costs passed to ratepayers are reasonable and prudent.

Effective, high-quality training programs, including apprenticeship initiatives and equitable labor agreements, could help to address some of the challenges of workforce availability and readiness. For example, experts identified the **California** Workforce Development Board's (CWDB) High Road Training Partnership, an industry-based training partnership, as a model for other states seeking to enhance workforce capacity. The High Road Training Partnership grew out of a legislative directive requiring the CWDB to report on workforce development and job training opportunities to help industry, workers, and communities transition in a green economy and ensure employers have a skilled workforce.[83] The Board provides funding for skilled internship and apprenticeship programs, including, for example, $4.7 million in grants to the Line Clearance Tree Trimmer certification program run by the California-Nevada Joint Apprenticeship Training Committee to address one of the root causes of wildfires.[84] Similarly, in 2023, **Colorado** adopted statutory provisions emphasizing the importance of training and apprenticeship programs alongside improved wage standards — to ensure workers receive living wages and to create a more prepared workforce for energy sector public works projects, including transmission.[85]

83 California Health and Safety Code § 38951.3.

84 California Workforce Development Board, "High Road: Line Clearance Tree Trimmer Education and Long Term Success," 2023; IBEW1245, "Celebrating the Grand Opening of the New Cal-Nev JATC Training Center in Woodland," Dec. 30, 2021.

85 Colorado Revised Statutes §§ 24-92-301 et seq.

G. A NOTE ON COMPETITION AND RIGHTS OF FIRST REFUSAL (ROFR)

A right of first refusal (ROFR) is a legal right that grants a person or company the opportunity to accept an offer on a deal before it is presented to any other potential party. In the context of transmission development, ROFR laws give incumbent transmission operators or utilities the first chance to build new or upgrade existing transmission lines before other companies are given the chance to propose a project to meet the identified need. In jurisdictions that lack ROFR, a regional project may be subject to a competitive solicitation process to determine who gets to develop it. In 2011, the Federal Energy Regulatory Commission barred ROFRs in federal tariffs for regionally cost-allocated projects, but states are still permitted to enact ROFRs as applied to transmission development within their states.

Numerous experts flagged state ROFR laws as having an important impact on transmission development and modernization, but there was not agreement on whether that impact was positive or negative. Experts pointed, for instance, to states (such as **Indiana**,[86] **Michigan**,[87] and **Minnesota**[88]) that have recently enacted laws supporting ROFRs, as well as to others (such as **Illinois**,[89] **Iowa**,[90] **Missouri**,[91] and **Wisconsin**[92]) where such legislation failed to advance. Experts disagreed as to whether the enactment of ROFR laws is beneficial or a hindrance to accelerating the buildout and modernization of transmission infrastructure.

Those in favor of state ROFRs assert that providing incumbent utilities with this right would result in more collaborative planning between utilities and regional planners, reduced project development timelines, and increased certainty. They emphasized that competitive solicitation processes add time to the development process – both in selecting a developer and after the developer is selected – which can lead to significant delays.[93] Additionally, they argue that cost-savings that were expected to be associated with these solicitations have not always materialized.[94]

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86 Indiana Code § 8-1-38-9.
87 Michigan Compiled Laws § 460.593.
88 Minnesota Stat. § 216B.246.
89 Illinois House Bill 3445 (2023).
90 Iowa House File 2551 (2024).
91 Missouri Senate Bill 568 (2023).
92 Wisconsin Senate Bill 481 (2023).
93 Concentric Energy Advisors, "Experience To-Date Shows Order No. 1000 Solicitations Fail to Show Benefits," August 2022 ("Concentric Report"); Dierker, B, "Building New Critical Infrastructure: No Time to Waste. Evaluating Cost Transparency between a Federal Right of First Refusal and Competitive Bidding in Electric Transmission Infrastructure Expansion," at 15-16, Alliance for Innovation and Infrastructure, July 2024 (citing Joskow, P., "Competition for Electric Transmission Projects in the USA FERC Order 1000," Massachusetts Institute for Technology, 2019).
94 Concentric Report.

On the other hand, those who oppose state ROFRs assert that competition encourages more innovative and cost-effective solutions, spurs greater development, and leads to lower estimates of costs associated with transmission development, though it was worth noting that the referenced estimates were based on projects that had not yet been developed.[95]

Others viewed the ROFR debate as a distraction from larger underlying issues.

CONCLUSION

This report is intended to explain the importance of transmission expansion and modernization, share state practices, spur conversations, and in some cases, flag types of legislation that could potentially hinder transmission development. ACEG welcomes comments and feedback on the policies discussed in this report and, just as importantly, any vital policies not discussed.

95 Pfeifenberger, J. et al., "Cost Savings Offered by Competition in Electric Transmission Experience to Date and the Potential for Additional Customer Value," The Brattle Group, April 2019.

APPENDIX
EXCERPTS OF STATE POLICIES

California Admin. Code Tit. 14 § 15220 et seq

Report Section II.B.1.a – *Siting and Permitting*, Streamlining Bureaucracy, Harmonizing Federal and State Processes

§ 15220. This article applies to projects that are subject to both CEQA and NEPA. NEPA applies to projects which are carried out, financed, or approved in whole or in part by federal agencies. Accordingly, this article applies to projects which involve one or more state or local agencies and one or more federal agencies.

§ 15221. NEPA Document Ready Before CEQA Document.

(a) When a project will require compliance with both CEQA and NEPA, state or local agencies should use the EIS or finding of no significant impact rather than preparing an EIR or negative declaration if the following two conditions occur:

(1) An EIS or finding of no significant impact will be prepared before an EIR or negative declaration would otherwise be completed for the project; and

(2) The EIS or finding of no significant impact complies with the provisions of these guidelines.

(b) Because NEPA does not require separate discussion of mitigation measures or growth inducing impacts, these points of analysis will need to be added, supplemented, or identified before the EIS can be used as an EIR.

§ 15222. Preparation of Joint Documents. If a lead agency finds that an EIS or finding of no significant impact for a project would not be prepared by the federal agency by the time when the lead agency will need to consider an EIR or negative declaration, the lead agency should try to prepare a combined EIR-EIS or negative declaration-finding of no significant impact. To avoid the need for the federal agency to prepare a separate document for the same project, the lead agency must involve the federal agency in the preparation of the joint document. The lead agency may also enter into a Memorandum of Understanding with the federal agency to ensure that both federal and state requirements are met. This involvement is necessary because federal law generally prohibits a federal agency from using an EIR prepared by a state agency unless the federal agency was involved in the preparation of the document.

California Pub. Util. Code § 1001.1

Report Section II.B.1.b – *Siting and Permitting*, Streamlining Bureaucracy, Coordinating Regional Planning and State Permitting

In a proceeding evaluating the issuance of a certificate of public convenience and necessity for a proposed transmission project, the commission shall establish a rebuttable presumption with regard to need for the proposed transmission project in favor of an Independent System Operator governing board-approved need evaluation if all of the following are satisfied:

(a) The Independent System Operator governing board has made explicit findings regarding the need for the proposed transmission project and has determined that the proposed project is the most cost-effective transmission solution.

(b) The Independent System Operator is a party to the proceeding.

(c) The Independent System Operator governing board-approved need evaluation is submitted to the commission within sufficient time to be included within the scope of the proceeding.

(d) There has been no substantial change to the scope, estimated cost, or timeline of the proposed transmission project as approved by the Independent System Operator governing board.

California Water Code § 80830

Report Section II.C.2 – *Costs and Financing*, Providing Public Funding and Financing for Transmission Projects

(a) There is hereby established in the State Treasury the Eligible Energy Resource Central Procurement Fund. . . all moneys in the fund are continuously appropriated, without regard to fiscal year, to the department for purposes of this division.

. . .

(d) Payments from the fund may be made only for the following purposes:

(1) Payment of any bonds or other contractual obligations authorized by this division.

(2) The cost of energy and transmission, scheduling, and other related expenses incurred by the department.

(3) The expenses incurred by the department in administering this division, including costs of personnel, contracts, or arrangements to carry out the department's duties and responsibilities pursuant to this division. . .

California Health and Safety Code § 38951.3

Report Part II.F.3 – *Creating an Ecosystem that Fosters Robust Evaluation and Development of Cost-Effective Transmission Solutions*, Enhancing Workforce Capacity

(a) . . . California Workforce Development Board, in consultation with the state board, shall report to the Legislature on the need for increased education, career technical education, job training, and workforce development resources or capacity to help industry, workers, and communities transition to economic and labor-market changes related to statewide greenhouse gas emissions reduction goals. . .

(b) The report to the Legislature shall address all of the following:

(1) Creating and retaining jobs and stimulating economic activity in the state.

(2) Imbedding workforce training and employment services in infrastructure investments so that services more directly connect to the jobs created.

(3) The use of community benefits agreements, community workforce agreements, and project labor agreements that connect workforce services and job training directly to jobs impacted or jobs created.

(4) Preparing the state's students with relevant career technical education that responds to business and industry demands.

(5) Developing worker retraining programs to assist the existing workforce with the necessary tools to upgrade their skills.

(6) Responding to the job creation and workforce needs of the state's new and emerging industries, including emerging technologies that will result in greater greenhouse gas emissions reductions. . .

(10) Identifying and leveraging state and federal funding resources to implement the recommendations made in the report consistent with the regulatory purposes of this division. . .

Colorado CRS § 40-42-109

Report Section II.A.1.c – *Planning,* Promoting the Development of Actionable Transmission Plans, Stand-Alone Statewide Transmission Studies

(1) The [Colorado Electric Transmission] authority shall expend money from the operational fund . . . to study the need for expanded transmission capacity in the state, including:

(a) The ability to expand capacity through the construction of new transmission lines, improvements to existing transmission lines, and connections to organized wholesale markets. . .;

(b) Whether and how expanded transmission capacity will:

(I) Improve the system reliability of the electric grid and provide optimal utilization of electricity flows in the state;

(II) Support the state's emission reduction goals . . .;

(III) Support the state's forecasted electricity needs; and

(IV) Reduce land impacts by using existing rights-of-way, including for large capacity transmission lines; co-locating multiple transmission lines; reconductoring transmission lines; and strategically siting new transmission corridors. . .

Colorado CRS § 40-42-101 et seq. (Article 42)

Report Section II.D.3 – *Strengthening the Ability of State Agencies to Engage in Transmission Planning and Development*, Consolidating Transmission Support and Decision-Making in a State Transmission Authority

Section 40-42-103. Authority - creation - board - open meetings and open records.

(1) The Colorado electric transmission authority is hereby created as an independent public body politic and corporate. The authority is a public instrumentality, and its exercise of the powers as authorized by this article 42 is the performance of an essential public function. The authority is a political subdivision of the state, is not an agency of state government, and is not subject to administrative direction by any department, commission, board, or agency of the state.

. . .

Section 40-42-104. General and specific powers and duties of the authority.

(1) . . . the authority, acting through the board, has the power to:. . .

(g) Make and enter into all contracts, leases, and agreements, including intergovernmental agreements and assignments of payments to host landowners, that are necessary or incidental to the performance of its duties and the exercise of its powers under this article 42, including:

(I) Contracts to purchase and dispose of eligible facilities;

(II) Contracts for the lease and operation by the authority of eligible facilities owned by an electric utility or other private person;

(III) Contracts for leasing eligible facilities owned by the authority, subject to the requirement that the authority deposit any revenue derived pursuant to the lease into the electric transmission bonding fund; and

(IV) Contracts for powerline trails pursuant to section 33-45-103;

. . .

(l) Enter into partnerships with public or private entities;

(m) Identify and establish corridors for the transmission of electricity within the state, subject to siting and land use approval by the local government with siting and land use authority pursuant to article 65.1 of title 24;

(n) Through participation in appropriate regional transmission forums and other organizations, including organized wholesale markets. . .coordinate, investigate, plan, priority ze, and negotiate with entities within and outside Colorado for the establishment of interstate transmission corridors and engage in other transmission planning activities that would increase grid reliability, help Colorado meet its clean energy goals, promote the construction and maintenance of powerline trails throughout the state, and aid in economic and community development;

(o) . . . conduct a transparent and competitive process to select a qualified transmission operator, as defined by the commission, to assume the responsibility to carry out all required financing, planning, acquisition, maintenance, and operation of eligible facilities necessary or useful for the accomplishment of the purposes of this article 42;

(p) . . . have and exercise the power of eminent domain for acquiring any property or rights-of-way, except property of an electric utility or property or rights-of-way owned by a local government, necessary for projects. . .

(r) Issue bonds as necessary to undertake a project;

(s) Collect payments of reasonable rates, fees, interest, or other charges from persons using eligible facilities to finance eligible facilities and for other services rendered by the authority. . .;

(t) Make determinations about the efficient use of existing rights-of-way on projects it proposes to develop as a precondition to pioneering new rights-of-way for such projects;

(u) Consider options and alternatives, including through studies contracted with independent expert analysts, to increase the efficient use of the transmission system and relieve constraints on the transmission system, which options and alternatives may include storage and advanced transmission technologies;. . .

Illinois 220 ILCS 5/8-512

Report Section II.A.1.b – *Planning*, Promoting the Development of Actionable Transmission Plans, Pairing Transmission Planning with the Identification of Resource Zones

(a) It is the policy of this State to promote cost-effective transmission system development that ensures reliability of the electric transmission system, lowers carbon emissions, minimizes long-term costs for consumers, and supports the electric policy goals of this State. The General Assembly finds that:

(1) Transmission planning, primarily for reliability purposes, but also for economic and public policy reasons is conducted by regional transmission organizations in which transmission-owning Illinois utilities and other stakeholders are members.

(2) Order No. 1000 of the Federal Energy Regulatory Commission requires regional transmission organizations to plan for transmission system needs in light of State public policies and to accept input from states during the transmission system planning processes.

(3) The State of Illinois does not currently have a comprehensive power and environmental policy planning process to identify transmission infrastructure needs that can serve as a vital input into the regional and interregional transmission organization planning processes conducted under Order No. 1000 and other laws and regulations.

(4) This State is an electricity generation and power transmission hub, and can leverage that position to invest in infrastructure that enables new and existing Illinois generators to meet the public policy goals of the State of Illinois and of interconnected states while cost-effectively supporting tens of thousands of jobs in the renewable energy sector in this State.

(5) The nation has a need to readily access this State's low-cost, clean electric power, and this State also desires access to clean energy resources in other states to develop and support its low-carbon economy and keep electricity prices low in Illinois and interconnected States.

(6) Existing transmission infrastructure may constrain the State's achievement of 100% renewable energy by 2050, the accelerated adoption of electric vehicles in a just and equitable way, and electrification of additional sectors of the Illinois economy.

(7) Transmission system congestion within this State and the regional transmission organizations serving this State limits the ability of this State's existing and new electric generation facilities that do not emit carbon dioxide, including renewable energy resources and zero emission facilities, to serve the public policy goals of this State and other states, which constrains investment in this State. . .

(9) Creating a forward-looking plan for this State's electric transmission infrastructure, as opposed to relying on case-by-case development and repeated marginal upgrades, will achieve a lower-cost system for Illinois' electricity customers. A forward-looking plan can also help integrate and achieve a comprehensive set of objectives and multiple state, regional, and national policy goals.

(10) Alternatives to overhead electric transmission lines can achieve cost-effective resolution of system impacts and warrant investigation of the circumstances under which those alternatives should be considered and approved. The alternatives are likely to be beneficial as investment in electric transmission infrastructure moves forward.

(11) Because transmission planning is conducted primarily by the regional transmission organizations, the Commission should be advocating for the State's interests at the regional transmission organizations to ensure that such planning facilitates the State's policies and goals, including overall consumer savings, power system reliability, economic development, environmental improvement, and carbon reduction.

(b) Consistent with the findings identified in subsection (a), the Commission shall open an investigation to develop and adopt a renewable energy access plan. . .To assist and support the Commission in the development of the plan, the Commission shall retain the services of technical and policy experts with relevant fields of expertise, solicit technical and policy analysis from the public, and provide for a 120-day open public comment period after publication of a draft report, which shall be published no later than 90 days after the comment period ends. The plan shall, at a minimum, do the following:

. . .

(2) develop a plan to achieve transmission capacity necessary to deliver the electric output from renewable energy technologies in the renewable energy access plan zones to customers in Illinois and other states in a manner that is most beneficial and cost-effective to customers;

. . .

(4) consider programs, policies, and electric transmission projects that can be adopted within this State that promote the cost-effective delivery of power from renewable energy resources interconnected to the bulk electric system to meet the renewable portfolio standard targets under subsection (c) of Section 1-75 of the Illinois Power Agency Act;

(5) consider proposals to improve regional transmission organizations' regional and interregional system planning processes, especially proposals that reduce costs and emissions, create jobs, and increase State and regional power system reliability to prevent high-cost outages that can endanger lives, and analyze of how those proposals would improve reliability and cost-effective delivery of electricity in Illinois and the region; . . .

Louisiana SB108 (2024) amending Rev. Stat. §19:2(7)

Report Section II.B.4 – *Siting and Permitting*, Considering the Broader Benefits of Regional Transmission in Siting Processes

Section 1. R.S. 19:2(7) is hereby amended and reenacted to read as follows:

§2. Expropriation by state or certain corporations, limited liability companies, or other legal entities

Prior to filing an expropriation suit, an expropriating authority shall attempt in good faith to reach an agreement as to compensation with the owner of the property sought to be taken . . . If unable to reach an agreement with the owner as to compensation, any of the following may expropriate needed property:

(7) Any domestic or foreign corporation, limited liability company, or other legal entity created for the purpose of, or engaged in, generating, transmitting, and distributing or for transmitting or distributing electricity and steam for power, lighting, heating, or other such uses subject to the following qualifications. Property located in Louisiana may be expropriated exclusively by an electric public utility as defined in R.S. 45:121 or an affiliated entity either for a transmission or generation project that is approved and included in a multi=state regional transmission organization's or independent system operator's transmission expansion plan or identified by such regional transmission organization or independent system operator as necessary for the reliability of the electric system or necessary for the interconnection of a generator, or for generating plants, buildings, transmission lines, stations or substations, distribution lines, or other associated facilities if a majority of the electricity or steam power to be generated, transmitted, or distributed in connection with these intended facilities will be delivered to end-users located within Louisiana. . . .The terms "Regional Transmission Organization" and "Independent System Operator" shall have the meanings provided by 16 U.S.C. 796. In the event that any provision or provisions of this Paragraph are declared invalid or unenforceable by any court of competent jurisdiction, the remaining terms and provisions that are not affected thereby shall remain in full force and effect.

Maryland Pub.Util. Code § 7-704.3

Report Section II.A.1.b – *Planning*, Promoting the Development of Actionable Transmission Plans, Pairing Transmission Planning with the Identification of Resource Zones

(a) The General Assembly finds and declares that it is in the public interest to upgrade and expand the transmission system to accommodate the buildout of at least 8,500 megawatts of offshore wind energy from qualified offshore wind projects serving the State by 2031.

(b) (1) To meet the goals established under § 7–703 of this subtitle and subsection (a) of this section, the Commission, in consultation with the Maryland Energy Administration, shall request that PJM Interconnection conduct an analysis of transmission system upgrade and expansion options that take into consideration both onshore and offshore infrastructure.

(2) The Commission: (i) shall consult with other states served by PJM Interconnection to evaluate regional transmission cooperation that could help achieve the State's renewable energy and offshore wind energy goals with greater efficiency;. . . (iii) may consult with owners of transmission facilities in the State to gather relevant technical information.

(3) The Commission may enter into any necessary agreements with PJM Interconnection for transmission planning to: (i) initiate PJM Interconnection's analysis; or (ii) assist with the solicitation of proposals for offshore wind transmission projects. . .

(c) (1) On or before July 1, 2025, the Commission shall issue, or request that PJM Interconnection issue, one or more competitive solicitations for proposals for open access offshore wind transmission facilities and complementary onshore transmission upgrades and expansions.

(2) The Commission may issue, or request that PJM Interconnection issue, further solicitations for proposals after this date if determined necessary by the Commission.

(d) In developing criteria for selecting a proposal under this section, the Commission:

(1) shall consider the analysis required under subsection (b) of this section, including a consideration of potential interconnection points;

(2) shall evaluate the potential for cooperating with other states in the PJM region to maximize consumer benefits that will best achieve the State's renewable energy and offshore wind energy goals; and

(3) may consult with the Administration, electric companies, transmission facility owners, and other states or entities designated by those states in developing or coordinating equivalent standards for the approval of transmission projects under this section that will facilitate the integration of multiple offshore wind energy projects and potential multistate offshore wind transmission projects.

. . .

(j) If the Commission finds that none of the proposals adequately support the goals established under this section or demonstrate net benefits to ratepayers in the State when compared with an alternative baseline scenario under subsection (e)(1)(v) of this section, then the Commission may end the solicitation process without selecting a proposal.

(k). . .(2) The requirement to obtain a certificate of public convenience and necessity . . . does not apply to a proposal selected . . .

(3) An order selecting a proposal . . . constitutes authorization by the Commission to construct and operate facilities that would otherwise require a certificate of public convenience and necessity. . .

Michigan MCL § 460.6t

Report Section II.A.1.a – *Planning*, Promoting the Development of Actionable Transmission Plans, Utility Integrated Resource Plans

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(3) Not later than April 20, 2019, each electric utility whose rates are regulated by the commission shall file with the commission an integrated resource plan that provides a 5-year, 10-year, and 15-year projection of the utility's load obligations and a plan to meet those obligations, to meet the utility's requirements to provide generation reliability. . .

(5) An integrated resource plan must include all of the following:

. . .

(g) An analysis of potential new or upgraded electric transmission options for the electric utility.

(h) Data regarding the utility's current generation portfolio, including the age, capacity factor, licensing status, and remaining estimated time of operation for each facility in the portfolio.

(i) Plans for meeting current and future capacity needs with the cost estimates for all proposed construction and major investments, including any transmission or distribution infrastructure that would be required to support the proposed construction or investment, and power purchase agreements.. . .

Minnesota SF 4942 (Chapter 126) Art. 8, Section 1 (2024), amending Stat. § 216B.2421 and Stat. § 216B.2423

Report Section II.B.1.c – *Planning*, Streamlining Bureaucracy, Coordinating Interstate Processes

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216B.2421 DEFINITION OF LARGE ENERGY FACILITY.

Subd. 2.Large energy facility. "Large energy facility" means: . . .

(2) any high-voltage transmission line with a capacity of 200 300 kilovolts or more and greater than 1,500

feet one mile in length in Minnesota;

(3) any high-voltage transmission line with a capacity of 100 kilovolts or more with more than ten miles of its length in Minnesota or that crosses a state line; . . .

216B.243 CERTIFICATE OF NEED FOR LARGE ENERGY FACILITY.

Subd. 2. Certificate required.

No large energy facility shall be sited or constructed in Minnesota without the issuance of a certificate of need by the commission pursuant to sections 216C.05 to 216C.30 and this section and consistent with the criteria for assessment of need.

Subd. 3. Showing required for construction.
No proposed large energy facility shall be certified for construction unless the applicant can show that demand for electricity cannot be met more cost effectively through energy conservation and load-management measures and unless the applicant has otherwise justified its need. In assessing need, the commission shall evaluate:

(1) the accuracy of the long-range energy demand forecasts on which the necessity for the facility is based;

(2) the effect of existing or possible energy conservation programs under sections 216C.05 to 216C.30 and this section or other federal or state legislation on long-term energy demand;

(3) the relationship of the proposed facility to overall state energy needs. . .or in the case of a high-voltage transmission line, the relationship of the proposed line to regional energy needs. . .;

(4) promotional activities that may have given rise to the demand for this facility;

(5) benefits of this facility, including its uses to protect or enhance environmental quality, and to increase reliability of energy supply in Minnesota and the region;

(6) possible alternatives for satisfying the energy demand or transmission needs including but not limited to potential for increased efficiency and upgrading of existing energy generation and transmission facilities, load-management programs, and distributed generation, except that the commission must not require evaluation of alternative end points for a high-voltage transmission line qualifying as a large energy facility unless the alternative end points are (i) consistent with end points identified in a federally registered planning authority transmission plan, or (ii) otherwise agreed to for further evaluation by the applicant;

. . .

(9) with respect to a high-voltage transmission line, the benefits of enhanced regional reliability, access, or deliverability to the extent these factors improve the robustness of the transmission system or lower costs for electric consumers in Minnesota;. . .

Minnesota HF 5247 (Chapter 127), Article 3, Section 17-19 (2024), amending Minn. Stat. § 161.45

Report Section II.B.2 – *Siting and Permitting*, Leveraging Existing Rights-of-Way

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section 161.45, is amended by adding [] subdivision[s] to read:

Subd. 4. High voltage transmission; placement in right-of-way.

. . .

(b) . . .high voltage transmission lines under the laws of this state or the ordinance of any city or county may be constructed, placed, or maintained across or along any trunk highway, including an interstate highway and a trunk highway that is an expressway or a freeway, except as deemed necessary by the commissioner of transportation to protect public safety or ensure the proper function of the trunk highway system.

(c) If the commissioner denies a high voltage electric line colocation request, the reasons for the denial must

be submitted for review within 90 days of the commissioner's denial to the chairs and ranking minority members of the legislative committees with jurisdiction over energy and transportation, the Public Utilities Commission executive secretary, and the commissioner of commerce.

Subd. 5. High voltage transmission; coordination required. Upon written request, the commissioner must engage in coordination activities with a utility or transmission line developer to review requested highway corridors for potential permitted locations for transmission lines. The commissioner must assign a project coordinator within 30 days of receiving the written request. The commissioner must share all known plans with affected utilities or transmission line developers on potential future projects in the highway corridor if the potential highway project impacts the placement or siting of high voltage transmission lines.

Subd. 6. High voltage transmission; constructability report; advance notice.

(a) If the commissioner and a utility or transmission line developer identify a permittable route along a trunk highway corridor for possible colocation of transmission lines, a constructability report must be prepared by the utility or transmission line developer in consultation with the commissioner. A constructability report developed under this subdivision must be used by both parties to plan and approve colocation projects.

(b) A constructability report developed under this section between the commissioner and the parties seeking colocation must include terms and conditions for building the colocation project. Notwithstanding the requirements in subdivision 1, the report must be approved by the commissioner and the party or parties seeking colocation prior to the commissioner approving and issuing a permit for use of the trunk highway right-of-way.

(c) A constructability report must include an agreed upon time frame for which there may not be a request from the commissioner for relocation of the transmission line. If the commissioner determines that relocation of a transmission line in the trunk highway right-of-way is necessary, the commissioner, as much as practicable, must give a four-year advance notice.

(d) . . . if the commissioner requires the relocation of a transmission line in the interstate highway right-of-way earlier than the agreed upon time frame in paragraph (c) in the constructability report or provides less than a four-year notice of relocation in the agreed upon constructability report, the commissioner is responsible for 75 percent of the relocation costs.

Minnesota SF 4942, (Chapter 126) Article 6, Section 52 (2024)

Report Section II.E.3 – *Transmission Modernization*, Creating an Environment Encouraging GETs and High-Performance Conductors

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Subdivision 1. Definitions. (a) For the purposes of this section, the following terms have the meanings given.

(b) "Capacity" means the maximum amount of electricity that can flow through a transmission line while observing industry safety standards.

(c) "Congestion" means a condition in which a lack of transmission line capacity prevents the delivery of the lowest-cost electricity dispatched to meet load at a specific location.

(d) "Dynamic line rating" means hardware or software used to calculate the thermal limit of existing transmission lines at a specific point in time by incorporating information on real-time and forecasted weather conditions.

(e) "Grid enhancing technology" means hardware or software that reduces congestion or enhances the flexibility of the transmission system by increasing the capacity of a high-voltage transmission line or rerouting electricity from overloaded to uncongested lines, while maintaining industry safety standards. Grid enhancing technologies include but are not limited to dynamic line rating, advanced power flow controllers, and topology optimization.

(f) "Line rating methodology" means a methodology used to calculate the maximum amount of electricity

that can be carried by a transmission line without exceeding thermal limits designed to ensure safety.

(g) "Power flow controller" means hardware and software used to reroute electricity from overloaded transmission lines to underutilized transmission lines.

(h) "Thermal limit" means the temperature a transmission line reaches when heat from the electric current flow within the transmission line causes excessive sagging of the transmission line.

(i) "Topology optimization" means a software technology that uses mathematical models to identify reconfigurations in the transmission grid in order to reroute electricity from overloaded transmission lines to underutilized transmission lines.

(j) "Transmission line" has the meaning given to "high-voltage transmission line" . . .

(k) "Transmission system" means a network of high-voltage transmission lines owned or operated by an entity subject to this section that transports electricity to Minnesota customers.

Subd. 2. Report; content. An entity that owns more than 750 miles of transmission lines in Minnesota. . . must include in that report information that:

(1) identifies, during each of the last three years, locations that experienced 168 hours or more of congestion, or the ten locations at which the most costly congestion occurred, whichever measure produces the greater number of locations;

(2) estimates the frequency of congestion at each location and the increased cost to ratepayers resulting from the substitution of higher-priced electricity;

(3) identifies locations on each transmission system that are likely to experience high levels of congestion during the next five years;

(4) evaluates the technical feasibility and estimates the cost of installing one or more grid enhancing technologies to address each instance of grid congestion identified in clause (1), and projects the grid enhancing technology's efficacy in reducing congestion;

(5) analyzes the cost-effectiveness of installing grid enhancing technologies to address each instance of congestion identified in clause (1) by using the information developed in clause (2) to calculate the payback period of each installation, using a methodology developed by the commission;

(6) proposes an implementation plan, including a schedule and cost estimate, to install grid enhancing technologies at each congestion point identified in clause (1) at which the payback period is less than or equal to a value determined by the commission, in order to maximize transmission system capacity; and

(7) explains the transmission owner's current line rating methodology.

Subd. 3. Commission review; order.

(a) The commission must review the implementation plans proposed by each reporting entity . . .and must:

(1) review, and may approve, reject, or modify, the plan; and

(2) issue an order requiring implementation of an approved plan.

(b) Within 90 days of the date the commission issues an order under this subdivision each public utility must file with the commission a plan containing a workplan, cost estimate, and schedule to implement the elements of the plan approved by the commission that are located within the public utility's electric service area. For each entity required to report under this section that is not a public utility, the commission's order is advisory.

Subd. 4. Cost recovery. Notwithstanding any other provision of this chapter, the commission may approve cost recovery under Minnesota Statutes, section 216B.16, including an appropriate rate of return, of any prudent and reasonable investments made or expenses incurred by a public utility to administer and implement a grid enhancing technologies plan approved by the commission under this section.

Montana Code § 69-3-714

Report Section II.E.3 – *Transmission Modernization*, Providing Financial Incentives or Reducing Financial Risk for Transmission Modernization Investments, Incentivizing Advanced Transmission Technologies through a Return on Equity Bump

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Criteria for allowable advanced conductor programs.

(1) The commission may approve cost-effectiveness criteria for advanced conductor projects that may be placed into a utility's rate base under this part.

(2) Criteria must be based on established direct current resistance at standard pressure and a temperature of 20 degrees Celsius.

(3) As used in this section, "advanced conductor" means an overhead electricity conductor installed in a transmission or distribution project that has a direct current electrical resistance at least 10% lower than existing conductors of a similar diameter on the system.

(4) In establishing cost-effectiveness criteria, the commission may consider decreased electrical losses and any other relevant consumer, environmental, and system benefits provided by advanced conductors.

Nevada NRS 704.834, 704.870, and 704.877

Report Section II.B.1.a – *Siting and Permitting*, Streamlining Bureaucracy, Harmonizing Federal and State Processes

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NRS 704.834 "Appropriate federal agency" defined. "Appropriate federal agency" means a federal agency responsible for the enforcement of environmental laws whose approval is required for the construction of a utility facility.

NRS 704.870 Requirements for filing application: Form and contents; procedure when federal agency is required to conduct environmental analysis; time for filing application; service; public notice.

. . .

2. If a person wishes to obtain a permit for a utility facility and a federal agency is required to conduct an environmental analysis of the proposed utility facility, the person must:

(a) Not later than the date on which the person files with the appropriate federal agency an application for approval for the construction of the utility facility, file with the Commission and each other permitting entity a notice, in such a form as the Commission or other permitting entity prescribes; and

(b) Not later than 30 days after the issuance by the appropriate federal agency of either the final environmental assessment or final environmental impact statement, but not the record of decision or similar document, relating to the construction of the utility facility:

(1) File with the Commission an application that complies with the provisions of subsection 1; and

(2) File with each other permitting entity an application for a permit, license or other approval for the construction of the utility facility. . .

NRS 704.877 Duty to accept and incorporate findings and conclusions of environmental review that already has been conducted; duplicative review prohibited; exception; duty to cooperate and coordinate to avoid duplication of activities.

1. Except as otherwise provided in this subsection, if an environmental review relating to the construction of a utility facility in its entirety, or to the construction of any portion of a utility facility, has already been conducted by an appropriate federal agency or by a state, regional or local agency, the Commission and each other permitting entity:

(a) Shall accept and incorporate the findings and conclusions made in that review into any application

for a permit, license or other approval for the construction of the utility facility which is filed with the Commission or other permitting entity; and

(b) Shall not conduct any duplicative environmental review on the application.

>The Commission or other permitting entity need not comply with the provisions of this subsection if the Commission or other permitting entity has already completed its own environmental review.

2. The Commission and other permitting entities shall cooperate with each other and the appropriate federal agencies on applications for permits, licenses and other approvals to construct a utility facility and coordinate their activities, including, without limitation, conducting hearings or environmental reviews, to avoid duplication of activities.

New Mexico Statutes §§ 62-16A-2 et seq.

Report Section II.D.3 – *Strengthening the Ability of State Agencies to Engage in Transmission Planning and Development*, Consolidating Transmission Support and Decision-Making in a State Transmission **Authority and Report Section II.C.2** – *Costs and Financing*, Providing Public Funding and Financing for Transmission Projects

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62-16A-3.A. The "New Mexico renewable energy transmission authority" is created as a public body, politic and corporate, separate and apart from the state, constituting a governmental instrumentality for the performance of essential public functions . . .

62-16A-4. Authority; duties and powers . . .B. The authority may:. . .

(2) enter into contractual agreements with respect to one or more projects upon the terms and conditions the authority considers advisable;. . .

(4) enter into partnerships with public or private entities;

(5) identify and establish corridors for the transmission of electricity within the state;.

(6) through participation in appropriate regional transmission forums, coordinate, investigate, plan, prioritize and negotiate with entities within and outside the state for the establishment of interstate transmission corridors;

(7) . . . finance or plan, acquire, maintain and operate eligible facilities necessary or useful for the accomplishment of the purposes of the New Mexico Renewable Energy Transmission Authority Act;

(8) . . .exercise the power of eminent domain for acquiring property or rights of way for public use if needed for projects if such action does not involve taking utility property or does not materially diminish electric service reliability of the transmission system in New Mexico. . .;

(9) receive by gift, grant, donation or otherwise, any sum of money, aid or assistance from the United States, the state of New Mexico, any other state, any political subdivision or any other public or private entity;

(11) issue bonds pursuant to the New Mexico Renewable Energy Transmission Authority Act as necessary to undertake a project;

(12) enter into contracts for the lease and operation by the authority of eligible facilities owned by a public utility or other private person;

(13) enter into contracts for leasing eligible facilities owned by the authority. . .;

(14) collect payments of reasonable rates, fees, interest or other charges from persons using eligible facilities to finance eligible facilities and for other services rendered by the authority. . .;

(15) borrow money necessary to carry out the purposes of the New Mexico Renewable Energy Transmission Authority Act and mortgage and pledge any leases, loans or contracts executed and delivered by the authority;

New York Consolidated Laws Pub. Service Chapter 48, Art. 1 § 3-C

Report Section II.B.1.d – *Siting and Permitting*, Streamlining Bureaucracy, Reducing Intrastate Inefficiencies

§ 3-c. Office of renewable energy siting and electric transmission.

. . .

2. General powers and responsibilities. (a) There is hereby established in the department [of Public Service] an office of renewable energy siting and electric transmission.

(b) ORES shall accept applications and evaluate, issue, amend, and approve the assignment and/or transfer of siting permits pursuant to article VIII of this chapter. ORES shall exercise its authority by and through the executive director.

(c) ORES, by and through the executive director, shall be authorized to conduct hearings and dispute resolution proceedings, issue permits, and adopt, subject to the approval of the public service commission, such rules, regulations and procedures as may be necessary, or any amendments or modifications thereto, convenient, or desirable to effectuate the purposes of this section and article VIII of this chapter.

(d) ORES shall, among other things, continue unimpeded the work of the office of renewable energy siting established under the former section ninety-four-c of the executive law. All permits issued by the former office of renewable energy siting, established pursuant to former section ninety-four-c of the executive law, and all certificates of environmental compatibility and public need issued by the commission pursuant to article VII of this chapter shall be considered for all legal purposes to be permits issued by ORES.

(e) All final siting permits issued by ORES or heretofore issued by the office of renewable energy siting established pursuant to the former section ninety-four-c of the executive law are hereby enforceable by ORES and the department pursuant to section twenty-four, section twenty-five, and section twenty-six of this article as if issued by the commission, except that such permits issued to combination gas and electric corporations are also enforceable by ORES and the department pursuant to section twenty-five-a of this article. ORES and the department shall monitor, enforce, and administer compliance with any terms and conditions set forth in a siting permit issued pursuant to article VIII of this chapter and in doing so may use and rely on authority provided to the commission otherwise available under this chapter. . . .

(f) At the request of ORES, all other state agencies and authorities are hereby authorized to provide support and render services to the office within their respective functions.

New York Consolidated Laws Pub. Service Chapter 48, Article 8, §§ 143, 144

Report Section II.B.1.d – *Siting and Permitting*, Streamlining Bureaucracy, Reducing Intrastate Inefficiencies

§ 143. Application, notice, and review relating to major electric transmission facility siting.

1. Notwithstanding any law to the contrary, ORES shall, within one hundred twenty days after its receipt of an application for a siting permit with respect to a major electric transmission facility, determine whether the application is complete and notify the applicant of its determination. If ORES does not deem the application complete, it shall set forth in writing delivered to the applicant the reasons why it has determined the application to be incomplete. If ORES fails to make a determination within the foregoing one hundred twenty day time period, the application shall be deemed complete; provided, however, that the applicant may consent to an extension of the one hundred twenty day time period for determining application completeness. Provided, further, that no application may be complete without proof of consultation with the municipality or political subdivision where the project is proposed to be located, or an agency thereof, prior to submission of an application to ORES, related to procedural and substantive requirements of local law.

. . .

3. To the greatest extent practicable, each landowner of land on which any portion of such proposed facility is to be located shall be served by first class mail with a notice that such landowner's property may be impacted by a project and an explanation of how to file with ORES a notice of intent to be a party in the permit application proceedings and the timeframe for filing such application.

4. No later than sixty days following the date upon which an application has been deemed complete, and following consultation with any relevant state agency or authority, ORES shall publish for public comment draft permit conditions prepared by the office of renewable energy siting and electric transmissions, which comment period shall be for a minimum of sixty days from public notice thereof. . .

5. For any municipality, political subdivision or an agency thereof that has received notice of the filing of an application. . the municipality or political subdivision or agency thereof shall within the timeframes established by this act submit a statement to ORES indicating whether the proposed facility is designed to be sited, constructed and operated in compliance with applicable local laws and regulations, if any, concerning the environment, or public health and safety. In the event that a municipality, political subdivision or an agency thereof submits a statement to ORES that the proposed facility is not designed to be sited, constructed or operated in compliance with local laws and regulations and ORES determines not to hold an adjudicatory hearing on the application, ORES shall hold a non-adjudicatory public hearing in the affected municipality or political subdivision.

6. If public comments on a draft permit condition published by ORES pursuant to this section, including comments provided by a municipality or political subdivision or agency thereof, landowners, or members of the public, raise a substantive and significant issue, as defined in regulations adopted pursuant to this article, that requires adjudication, ORES shall promptly fix a date for an adjudicatory hearing to hear arguments and consider evidence with respect thereto. . . In any such adjudicatory hearing, ORES or the department, shall designate members of its staff to represent the public interest, including with respect to the application of local and state laws.

7. Following the expiration of the public comment period set forth in this section, and following the conclusion of a hearing . . . ORES shall, in the case of a public comment period, issue a written summary of public comments and an assessment of comments received, and in the case of an adjudicatory hearing, the executive officer or any person to whom the executive director has delegated such authority shall issue a final written hearing report. A final siting permit may only be issued if ORES makes a finding that the proposed project, together with any applicable uniform and site-specific standards and conditions, would comply with applicable laws and regulations. In making a final siting permit determination with respect to a major renewable energy facility or a major electric transmission facility, ORES may elect not to apply, in whole or in part, any local law or ordinance that would otherwise be applicable if it makes a finding that, as applied to the proposed facility, it is unreasonably burdensome in view of the CLCPA targets, the environmental benefits, and in the case of a transmission facility, the public need for the proposed project.

8. Notwithstanding any other deadline made applicable by this section, ORES shall make a final decision on a siting permit within one year from the date the application was deemed complete. Unless ORES and the applicant have agreed to an extension and if a final siting permit decision has not been made by ORES within such time period, then such siting permit shall be deemed to have been automatically granted for all purposes set forth in this article and all uniform conditions or site specific permit conditions issued for public comment shall constitute enforceable provisions of the siting permit; provided, however, that with respect to a final siting permit decision related to a major electric transmission facility, any portion of which is to be located on the land of a landowner for which the applicant lacks an existing right-of-way agreement and in which ORES has not made a public need determination, no such permit shall be automatically granted.

9. For a major electric transmission facility that would be constructed substantially within existing rights-of-way that possess existing major electric transmission infrastructure, the office of renewable energy siting

and electric transmission may include within its regulations a framework that relieves certain requirements of this article, provided that such relief is reasonable and does not impair any rights of municipalities established under this article or limit requirements relating to public notice or the finding of public need.

§ 144. Powers of municipalities and state agencies and authorities.

1. Applicants shall, prior to filing an application, conduct meetings with the respective chief executive officer of all municipalities in which the proposed major renewable generation facility or major electric transmission facility will be located. The applicant shall provide as part of the application presentation materials and a summary of questions raised, and responses provided during such meetings with municipalities. In the event the applicant is unable to secure a meeting with a relevant municipality the application shall contain a detailed explanation of all of the applicant's best efforts and reasonable attempts to secure such meeting, including, but not limited to, written communications between the applicant and the municipality.

2. Notwithstanding any other provision of law, . . . no other state agency, department or authority, or any municipality or political subdivision or any agency thereof may, except as expressly authorized under this article or the rules and regulations promulgated under this article, require any approval, consent, permit, certificate, contract, agreement, or other condition for the development, design, construction, operation, or decommissioning of . . a major electric transmission facility with respect to which an application for a siting permit has been filed, provided in the case of a municipality, political subdivision or an agency thereof, such entity has received notice of the filing of the application therefor. Notwithstanding the foregoing, the department of environmental conservation shall be the permitting agency for permits issued pursuant to federally delegated or federally approved programs.

North Dakota Century Code Chapter 17 § 05

Report Section II.D.3 – *Strengthening the Ability of State Agencies to Engage in Transmission Planning and Development*, Consolidating Transmission Support and Decision-Making in a State Transmission Authority **and Report Section II.C.2** – *Costs and Financing*, Providing Public Funding and Financing for Transmission Projects

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17-05-02. North Dakota transmission authority. There is created the North Dakota transmission authority ["authority"], which shall be governed by the industrial commission.

. . .

17-05-05. Powers. The authority has all powers necessary to carry out the purposes of this chapter, including the power to:

1. Make grants or loans and to provide other forms of financial assistance as necessary or appropriate for the purposes of this chapter; . . .

3. Borrow money and issue evidences of indebtedness as provided in this chapter;
4. Receive and accept aid, grants, or contributions of money or other things of value from any source, including aid, grants, or contributions from any department, agency, or instrumentality of the United States, subject to the conditions upon which the aid, grants, or contributions are made and consistent with the provisions of this chapter;

. . .

10. To the extent and for the period of time necessary for the accomplishment of the purposes for which the authority was created, plan, finance, develop, acquire, own in whole or in part, lease, rent, and dispose of transmission facilities;

11. Enter contracts to construct, maintain, and operate transmission facilities;

12. Consult with the public service commission, regional organizations, and a

other relevant state or federal authority or persons as necessary and establish reasonable fees, rates, tariffs, or other charges for transmission facilities and all services rendered by the authority;

13. Lease, rent, and dispose of transmission facilities owned pursuant to this chapter;

14. Investigate, plan, prioritize, and propose corridors of the transmission of electricity;

15. Participate in and join regional transmission organizations;

16. Participate in studies of transmission options for the purpose of identifying opportunities for private transmission investment or private public investment options in transmission which will increase opportunity for export from the state consistent with maintaining a stable grid for the load serving entities in North Dakota; . . .

17-05-06. Authority may act. 1. The authority shall coordinate its plans for transmission facilities with regional organizations having transmission planning responsibilities for the project area. . .

17-05-07. Authority may participate upon request. The authority may participate in a transmission facility through financing, planning, joint ownership, or other arrangements at the request of a person giving a notice of intent.

Oregon ORS 469.370(13)

Report Section II.B.1.a – *Siting and Permitting*, Streamlining Bureaucracy, Harmonizing Federal and State Processes

(13) For a facility that is subject to and has been or will be reviewed by a federal agency under the National Environmental Policy Act, 42 U.S.C. Section 4321, et seq., the council shall conduct its site certificate review, to the maximum extent feasible, in a manner that is consistent with and does not duplicate the federal agency review. Such coordination shall include, but need not be limited to:

(a) Elimination of duplicative application, study and reporting requirements;

(b) Council use of information generated and documents prepared for the federal agency review;

(c) Development with the federal agency and reliance on a joint record to address applicable council standards;

(d) Whenever feasible, joint hearings and issuance of a site certificate decision in a time frame consistent with the federal agency review; and

(e) To the extent consistent with applicable state standards, establishment of conditions in any site certificate that are consistent with the conditions established by the federal agency.

Virginia HB 862 (2024) (amending VA Code §§ 56-597 and 56-599)

Report Section II.E.1.a – *Modernization*, Issuing Directives to Study GETs and High-Performance Conductors in State-Level Planning or Permitting Processes, Utility Studies

§§ 56-597 and 56-599 of the Code of Virginia are amended and reenacted as follows:

§ 56-597. Definitions. As used in this chapter:

"Advanced conductors" means hardware technology that can conduct electricity across transmission lines and that demonstrates enhanced performance over traditional conductor products.

. . .

"Grid-enhancing technologies" means a set of technologies that maximize the transmission of electricity across the electric distribution grid in a manner that ensures grid reliability and safeguards the cybersecurity and physical security of the electric distribution grid, including storage as a transmission asset, dynamic line rating, power flow control, and topology optimization.

"Integrated resource plan" or "IRP" means a document developed by an electric utility that provides a forecast of its load obligations and a plan to meet those obligations by supply side and demand side resources over the ensuing 15 years to promote reasonable prices, reliable service, energy independence, and environmental responsibility. . . .

§ 56-599. Integrated resource plan required.

A. Each electric utility shall file an updated integrated resource plan by October 15, in each year immediately preceding the year the utility is subject to a biennial review of rates for generation and distribution services filing. A copy of each integrated resource plan shall be provided to the Chairman of the House Committee on Commerce and Energy, the Chairman of the Senate Committee on Commerce and Labor, and the Chairman of the Commission on Electric Utility Regulation. After January 1, 2024, each electric utility not subject to an annual review shall file an annual update to the integrated resource plan by October 15, in each year that the utility is subject to review of rates for generation and distribution services filing. . . Each integrated resource plan shall consider options for maintaining and enhancing rate stability, energy independence, economic development including retention and expansion of energy-intensive industries, and service reliability.

B. In preparing an integrated resource plan, each electric utility shall systematically evaluate and may propose:

. . .

10. Long-term electric distribution grid planning and proposed electric distribution grid transformation projects, including a comprehensive assessment of the potential application of grid-enhancing technologies and advanced conductors in a manner that ensures grid reliability and safeguards the cybersecurity and physical security of the electric distribution grid. An electric utility that does not include grid-enhancing technologies or advanced conductors in an integrated resource plan shall include a detailed explanation of why such technologies or conductors are not included in such plan;

. . .

D. As part of preparing any integrated resource plan pursuant to this section, each utility shall conduct outreach to engage the public in a stakeholder review process and provide opportunities for the public to contribute information, input, and ideas on the utility's integrated resource plan, including the plan's development methodology, modeling inputs, and assumptions, as well as the ability for the public to make relevant inquiries, to the utility when formulating its integrated resource plan. Each utility shall report its public outreach efforts to the Commission. The stakeholder review process shall include representatives from multiple interest groups, including residential and industrial classes of ratepayers. Each utility shall, at the time of the filing of its integrated resource plan, report on any stakeholder meetings that have occurred prior to the filing date.

Washington SSB 5165 (2023) and RCW 19.280.030

Report Section II.A.1.a – *Planning*, Promoting the Development of Actionable Transmission Plans, Utility Integrated Resource Plans

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SSB 5165 NEW SECTION. Sec. 1.

(1) The legislature finds that the electric power system serving Washington will require additional high voltage transmission capacity to achieve the state's objectives and legal requirements. . . .

(3) Expanded transmission capacity and the more effective use of existing transmission capacity will provide benefits to electricity consumers in the state by enhancing the reliability of the electric power system and increasing access to more affordable sources of electricity within the state and across the western United States and Canada.

RCW 19.280.030 Development of a resource plan—Requirements of a resource plan—Clean energy action plan. Each electric utility must develop a plan consistent with this section.

(1) Utilities with more than 25,000 customers that are not full requirements customers must develop or update an integrated resource plan by September 1, 2008. At a minimum, progress reports reflecting changing conditions and the progress of the integrated resource plan must be produced every two years thereafter. An updated integrated resource plan must be developed at least every four years subsequent to the 2008 integrated resource plan. The integrated resource plan, at a minimum, must include:

. . .

(f) An assessment and 20-year forecast of the availability of and requirements for regional generation and transmission capacity to provide and deliver electricity to the utility's customers and to meet the requirements of chapter 288, Laws of 2019 and the state's greenhouse gas emissions reduction limits in RCW 70A.45.020. The transmission assessment must identify the utility's expected needs to acquire new long-term firm rights, develop new, or expand or upgrade existing, bulk transmission facilities consistent with the requirements of this section and reliability standards;

(i) If an electric utility operates transmission assets rated at 115,000 volts or greater, the transmission assessment must take into account opportunities to make more effective use of existing transmission capacity through improved transmission system operating practices, energy efficiency, demand response, grid modernization, nonwires solutions, and other programs if applicable;

(ii) An electric utility that relies entirely or primarily on a contract for transmission service to provide necessary transmission services may comply with the transmission requirements of this subsection by requesting that the counterparty to the transmission service contract include the provisions of chapter 288, Laws of 2019 and chapter 70A.45 RCW as public policy mandates in the transmission service provider's process for assessing transmission need, and planning and acquiring necessary transmission capacity;

(iii) An electric utility may comply with the requirements of this subsection (1)(f) by relying on and incorporating the results of a separate transmission assessment process, conducted individually or jointly with other utilities and transmission system users, if that assessment process meets the requirements of this subsection. . .

Wisconsin Stat. § 1.12(6)

Report Section II.B.2 – *Siting and Permitting*, Leveraging Existing Rights-of-Way

(6) Siting of electric transmission facilities. In the siting of new electric transmission facilities, including high-voltage transmission lines. . . it is the policy of this state that, to the greatest extent feasible that is consistent with economic and engineering considerations, reliability of the electric system, and protection of the environment, the following corridors should be utilized in the following order of priority:

(a) Existing utility corridors.

(b) Highway and railroad corridors.

(c) Recreational trails, to the extent that the facilities may be constructed below ground and that the facilities do not significantly impact environmentally sensitive areas.

(d) New corridors.

Wisconsin Stat. § 196.491(3)(gm) and (3g) and Stat. § 19.969

Report Section II.B.3 – *Siting and Permitting*, Requiring Early and Collaborative Engagement with and Support For Communities Impacted By Projects

§196.491(3) Certificate of public convenience and necessity.

(gm) The commission may not approve an application filed after October 29, 1999, under this subsection for a certificate of public convenience and necessity for a high-voltage transmission line that is designed for operation at a nominal voltage of 345 kilovolts or more unless the approval includes the condition that the applicant shall pay the fees specified in sub. (3g) (a). If the commission has approved an application under this subsection for a certificate of public convenience and necessity for a high-voltage transmission line that is designed for operation at a nominal voltage of 345 kilovolts or more that was filed after April 1, 1999, and before October 29, 1999, the commission shall require the applicant to pay the fees specified in sub. (3g) (a). For any application subject to this paragraph, the commission shall determine the cost of the high-voltage transmission line, identify the counties, towns, villages and cities through which the high-voltage transmission line is routed and allocate the amount of investment associated with the high-voltage transmission line to each such county, town, village and city.

§196.491 (3g) Fees for certain high-voltage transmission lines

(a) A person who receives a certificate of public convenience and necessity for a high-voltage transmission line that is designed for operation at a nominal voltage of 345 kilovolts or more under sub. (3) shall pay the department of administration an annual impact fee as specified in the rules promulgated by the department of administration under s. 16.969 (2) (a) and shall pay the department of administration a one-time environmental impact fee as specified in the rules promulgated by the department of administration under s. 16.969 (2) (b).

(b) A person that pays a fee under par. (a) may not use the payment to offset any other mitigation measure that is required in an order by the commission under sub. (3) regarding the certificate of public convenience and necessity specified in par. (a).

§16.969 Fees for certain high-voltage transmission lines.

(1) In this section:

(a) "Commission" means the public service commission.

(b) "High-voltage transmission line" means a high-voltage transmission line [one mile in length together with associated facilities] . . .that is designed for operation at a nominal voltage of 345 kilovolts or more.

(2) The department shall promulgate rules that require a person who is issued a certificate of public convenience and necessity by the commission under s. 196.491 (3) for a high-voltage transmission line to pay the department the following fees:

(a) An annual impact fee in an amount equal to 0.3 percent of the cost of the high-voltage transmission line, as determined by the commission under s. 196.491 (3)(gm).

(b) A one-time environmental impact fee in an amount equal to 5 percent of the cost of the high-voltage transmission line, as determined by the commission under s. 196.491 (3)(gm).

(3) (a) The department shall distribute the fees that are paid by a person under the rules promulgated under sub. (2)(a) to each town, village and city that is identified by the commission under s. 196.491 (3)(gm) in proportion to the amount of investment that is allocated by the commission under s. 196.491 (3)(gm) to each such town, village and city.

(b) The fee that is paid by a person under the rules promulgated under sub. (2)(b) shall be distributed as follows:

1. The department shall pay 50 percent of the fee to each county that is identified by the commission

under s. 196.491 (3) (gm) in proportion to the amount of investment that is allocated by the commission under s. 196.491 (3)(gm) to each such county.

2. The department shall pay 50 percent of the fee to each town, village and city that is identified by the commission under s. 196.491 (3)(gm) in proportion to the amount of investment that is allocated by the commission under s. 196.491 (3)(gm) to each such town, village and city.

(4) A county, town, village, or city that receives a distribution under sub. (3)(b) may use the distribution only for park, conservancy, wetland or other similar environmental programs, unless the commission approves a different use under this subsection. A county, town, village, or city that receives a distribution may request in writing at any time that the commission approve a different use. The commission shall make a decision no later than 14 days after receiving such a request. The commission shall approve a request if it finds that the request is in the public interest.

ACKNOWLEDGMENTS

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Contributing Organizations Include: Acadia Center, Advanced Energy United, Alliance for Affordable Energy, BlueGreen Alliance, Clean Air Task Force, Clean Energy States Alliance, Colorado Electric Transmission Authority, Conservative Energy Network, CTC Global, Earthjustice, Evergreen Action, Exelon, Google, GridLab, Grid Strategies, Illinois Citizens Utility Board, Interwest Energy Alliance, ITC Holdings Corp., NextGen Highways, New Fundamentals, North Dakota Transmission Authority, Pine Gate Renewables, RMI, Southern Renewable Energy Association, UCS, VEIR Inc., Western Grid Group, WIRES

ACEG also thanks the Clean Grid Initiative for supporting the development of this report.

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Americans for a Clean Energy Grid

Americans for a Clean Energy Grid (ACEG) is a not-for-profit, broad-based, diverse coalition of stakeholders focused on the need to expand, integrate, and modernize the high-capacity grid in the United States to support reliable and resilient energy service at affordable rates. The ACEG coalition includes multi-state utilities and merchant transmission owners that develop, own, and operate transmission; trade groups that include transmission owners and transmission equipment manufacturers among their members; renewable energy trade groups and advocates; environmental advocacy organizations; buyers and consumers of energy; and energy policy experts.

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David Gardiner and Associates (DGA) was founded in 2001 to serve as a strategic advisor to organizations and businesses seeking a sustainable future. Our firm combines expertise developing research and analysis with deep understanding of clean energy markets and policy. DGA has worked for foundations, businesses, and non-profit advocacy groups to develop strategies to identify and promote policies that will advance clean energy and a low-carbon economy.

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