State Strategies for Accelerating Transmission Development for Renewable Energy

Executive Summary

Many states have established policies intended to increase the amount of electricity supplied to their citizens and business that is generated by renewable energy sources such as wind, solar and geothermal. Over the next decade, moving that electricity from generators to consumers will drive demand for significant amounts of new electric transmission capacity. Utilities and other developers of generation facilities and transmission lines are coming forward with proposals to meet that new demand, but the planning, siting, financing, and cost allocation of transmission lines present challenges to governors and other policymakers. Generation facilities that are fueled by renewable energy resources are often remotely located and building transmission lines that bring the electricity they generate to market requires the involvement of multiple state and federal players, increasing those challenges. States should develop strategies to improve project coordination and reduce uncertainty and delays in bringing renewable energy to market.

Governors have a key role to play in overcoming those challenges. Even though the siting of individual transmission lines is the task of independent utility regulators, state-level energy policies partly determine how generation resources and transmission will be developed. Those policies are often driven by the governor's office and related agencies, typically working with the state legislatures and utility regulators. It is critical that governors work with their utility regulators to clear the hurdles that impede transmission development and advance solutions that cross state lines by engaging with other governors, regional authorities and federal agencies.

Renewable or alternative energy portfolio standards that require renewable energy resources to account for a minimum percentage of power sold in a state are in place in 30 states and territories. Those standards, combined with complementary state policies, efforts by utilities to diversify the resources used to generate power in their markets, and the declining costs for renewable energy technologies, are expected to spur an additional 45 to 50 gigawatts (GW) of renewable generation capacity by 2025 accounting for nearly half of the total increase in the capacity to produce electricity between now and then.[1,2] If that growth occurs, the bulk of the electricity produced would flow from centralized generation facilities through high-voltage transmission lines to local distribution grids.[3] As a result, more than one-quarter of the transmission projects currently planned through 2019 are designed to carry power generated by new, non-hydropower renewable resources.[4] **Figures 1** and **2** below, comparing existing high-voltage transmission lines to proposed new high-voltage lines, illustrates the broader growth picture: annual transmission additions in the period from 2009 through 2018 are expected to be three times the level of annual additions of the previous three years.[5]

Transmission projects of any sort may face challenges related to planning, siting, financing, and cost allocation that can delay their development. For transmission projects designed to integrate renewable energy, those challenges are:

Figure 1. Existing High-Voltage Transmission System[6]

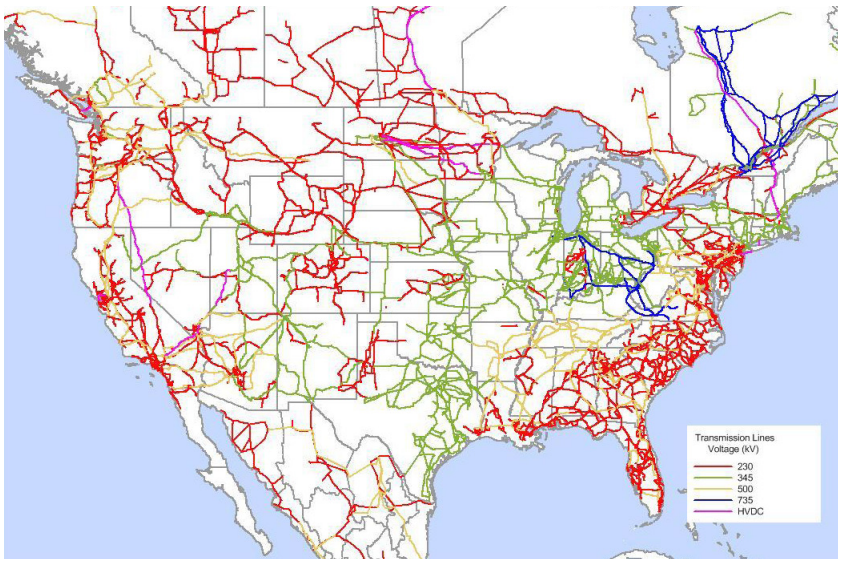
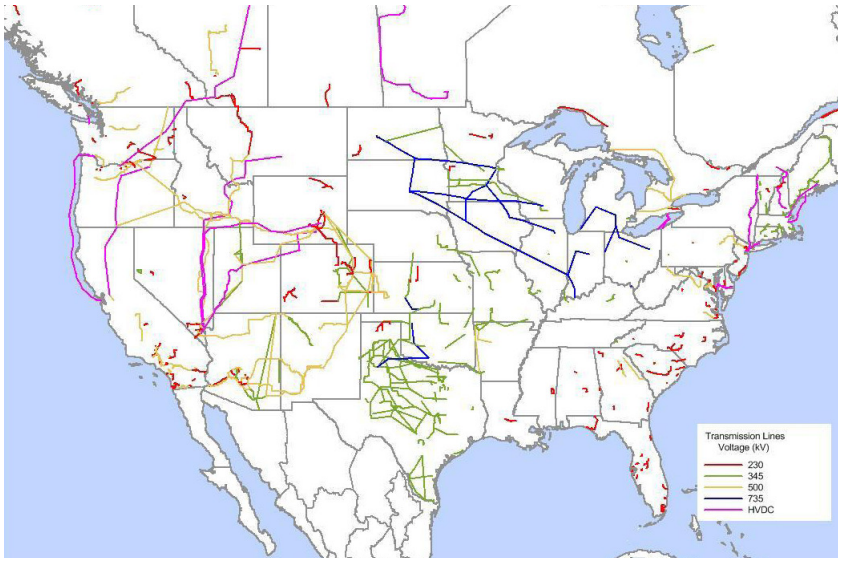


Figure 2. Proposed New High-Voltage Transmission Lines[7]



- **A planning process with overlapping boundaries.** Planning for new transmission lines, particularly those that carry power generated from renewable resources, often involves authorities from different regions and states. That process does not always adequately address coordination of lines that cross regional boundaries and few mechanisms exist to synchronize project development. That challenge exists more often for renewable transmission projects because those lines are more likely to cross multiple state borders or planning-region boundaries.
- **A lengthy siting process involving multiple permitting authorities.** A complex siting process is the norm for many new transmission lines but the locations of planned large-scale renewable projects are often long distances from the markets would they supply, making the process

even more difficult. That is because multiple state and federal agencies must participate in the siting process, adding to its length and complexity.

- **Difficulty securing early financing.** Developers run into a "chicken-or-egg" dilemma when building transmission lines to incorporate renewable energy: investors in transmission lines have trouble securing financial support without the guarantee of a generation facility, but investors in renewable generation facilities often cannot secure funding without transmission to bring their power to market. That dilemma is exacerbated by the fact that the permitting and construction of transmission generally takes much longer than the permitting and generation of most renewable generation.
- **Disagreement around allocating the costs of renewable energy transmission projects.** Allocating the costs of new transmission facilities—particularly those incorporating renewable energy—among utilities and ratepayers served by the lines can be a challenge for states. Areas of contention include: whether states should apply existing cost allocation methodologies to renewable energy projects; how states should define the benefits of a transmission project that incorporates renewable energy and determine who the beneficiaries are; and how broadly states should spread the costs.

To meet those challenges, states should develop ways to improve coordination and reduce delays in the construction of transmission for renewable energy. These include:

- **Participate in existing interconnection-wide planning forums.** States can take advantage of opportunities for planning beyond the rigid boundaries and time horizons of traditional transmission plans. The U.S. Department of Energy (DOE) has initiated ways for states to contribute to the nation's transmission planning process on a broader scale. Those efforts—covering the three interconnections[i] that traverse most of the United States—will model a variety of energy futures and provide a long-term resource and transmission analysis. States can use those efforts to better understand the transmission needs of the interconnections and help coordinate regional transmission planning authorities as renewable energy generation grows.[ii]
- **Plan and site renewable energy generation and transmission concurrently.** States can overcome uncertainties related to renewable energy by concurrently siting or, if applicable, concurrently planning transmission and generation. Several state and regional efforts are attempting to use coordinated planning or siting of energy facilities and transmission to accelerate the approval of new energy infrastructure. The Competitive Renewable Energy Zone (CREZ) process in **Texas** is on track to construct 2,300 miles of new transmission that will deliver nearly 18 GW of wind power to state population centers. The state coordinated the identification of cost-effective wind energy development areas with the selection of transmission providers and the permitting of transmission corridors.
- **Coordinate interstate siting with regional partners.** States can create or use existing regional forums to improve coordination in the siting and permitting phase for interstate transmission projects. The six New England states—**Connecticut**, **Maine**, **Massachusetts**, **New Hampshire**, **Rhode Island**, and **Vermont**—in 2009 adopted a *Renewable Energy Blueprint* that identified opportunities for coordinated renewable energy procurement and transmission siting. More recently, the six states created an Interstate Siting Collaborative to help imple-

i. The electric grid of continental United States is divided into three separate interconnections: the Eastern Interconnection, all or part of 39 states stretching from the Atlantic coast to eastern **Montana** and **New Mexico**; the Western Interconnection, all or part of 13 western states; and **Texas**.

ii. Utilities must participate in regional transmission planning efforts under Federal Energy Regulatory Commission Order 890. For more information on transmission planning regions, see the "Regional Divisions" section of this Issue Brief.

ment the blueprint. That effort involves exploring opportunities for coordination available under current state laws, such as the potential for common applications, concurrent timelines for siting proceedings, and information sharing among states.

- **Partner with federal agencies.** States can work directly with relevant federal agencies to improve the process for siting transmission across federal lands and waters. **California** has negotiated a memorandum of understanding with U.S. Department of the Interior (DOI) to expedite the siting of renewable energy projects and their associated transmission across federal lands. Subsequently, the state and DOI have sited nine renewable energy projects totaling four GW of new renewable energy capacity, with sufficient transmission to connect the power to the grid.
- **Develop centralized infrastructure to support further expansion.** States can facilitate the expansion of transmission and renewable energy capacity through the planning and prioritization of underlying high-capacity transmission infrastructure. **Michigan** provided expedited approval for a backbone transmission line in an area of the state with significant wind resource potential. The construction of that line will ensure that adequate infrastructure and transmission capacity are available to connect existing and planned wind resources in the area.
- **Create and use infrastructure financing authorities.** States can use existing, or create new, bonding authorities to fill financing gaps and add certainty to priority transmission projects. **New Mexico** created a bonding authority with the specific aim of financing renewable energy transmission projects. The state is using profits from the sale of wind power to customers in Arizona to pay back revenue bonds issued to finance the interconnecting transmission line. That financing mechanism allowed the state to develop a line it needed to meet renewable energy goals without spending its own resources.
- **Develop cost allocation methods for renewable energy projects.** States can work at the regional level to develop new or alternate cost allocation methods applicable to transmission projects that integrate renewable energy. For example, through a state-driven process involving **Illinois**, **Indiana**, **Iowa**, **Kentucky**, **Michigan**, **Minnesota**, **Missouri**, **Montana**, **North Dakota**, **Ohio**, **South Dakota**, and **Wisconsin**, the Midwest electricity market developed a new alternative methodology for allocating the transmission costs of projects seen as having a broader regional benefit, such as those that connect new renewable energy.

Those and other successful state efforts show governors how they can accelerate transmission development for renewable energy and help meet a variety of energy diversity, economic development, and environmental goals.

Background:Transmission Grid Basics

The U.S. transmission system has developed over the past 100 years from a few isolated lines to a network of more than 200,000 miles of transmission lines. The transmission system operates at high voltages—generally 100 kilovolts (kV) or above— with higher voltages able to carry more power over longer distances. The grid connects 750 gigawatts (GW) of generation facilities to local, lower voltage electric distribution systems throughout the country. For many years, the transmission grid grew with little consideration of how it would function as an interconnected system; individual utilities constructed individual lines to meet local electric needs. Eventually, utilities and regulators saw the need for a more coordinated approach.

State Roles and Regulations

Since the early 1900s, electric utilities have been subject to state regulation, including the determination of electricity rates and the siting and permitting of gen-

eration and transmission facilities. State public utility commissions (PUCs) are most often responsible for siting and permitting transmission lines, whether they are proposed by investor-owned utilities, private investors unaffiliated with a utility (or merchant transmission developers as they are called), public power districts, or rural electric cooperatives. Some states, such as **Connecticut** and **Ohio**, have a dedicated energy siting authority that approves major generation and transmission facilities. Others give siting authority to affected local jurisdictions but still require transmission developers to file environmental permits or Certificates of Public Convenience and Necessity (CPCN). State siting authority may also vary based on the voltage and size of the potential new transmission lines. For example, all transmission lines in **Arkansas** are required to apply for a CPCN. Lines greater than 100 kV and 10 miles in length or 170 kV and 1 mile in length require additional environmental review.[8]

Although state siting and permitting processes vary, there are some commonalities. Transmission developers submit an application to the state that includes an analysis of the need for the new line (e.g., to ensure grid reliability or connect new generation), cost estimates, and at least one proposed route. The state approval process often begins with granting overall approval for the line (perhaps by granting a CPCN) and any necessary environmental permits. The commission or siting authority in the state holds hearings, usually in one or more of the impacted communities, to determine the exact route of the line, address landowner and community concerns, and discuss alternatives to the transmission developer's proposed route. Most states combine their CPCN and siting approvals into one decision from the PUC or siting body. In other states, such as **Minnesota**, the determination of need and siting processes are distinct, although there have been efforts by the PUC to review and decide the two concurrently. For lines that cross private land, the state's siting body often has the power to grant eminent domain authority to the transmission developer, a power often assigned with the CPCN.[9] Transmission developers must obtain approval from each state crossed by a new transmission line.

Federal Roles and Regulations

In addition to state oversight of transmission, the federal government regulates specific aspects of transmission. The Federal Energy Regulatory Commission (FERC) has jurisdiction over interstate transmission and wholesale power sales. Various other federal agencies have permitting authority over transmission lines that cross federal lands or waters.

FERC. FERC's jurisdiction over the sale of most of the interstate wholesale power in the United States gives it a significant role in the regulation of new transmission.[iii] Following the passage of the 1992 Energy Policy Act, FERC issued a series of orders that restructured parts of the electric power industry, including:

- FERC Order 888, which required transmission providers to offer generators open access to their transmission at reasonable rates, leading to the formation of independent system operators (ISOs);
- FERC Order 890, which required transmission providers to participate in transparent, regional planning processes; and
- FERC Order 2000, which allowed and encouraged the creation of regional transmission organizations (RTOs) to coordinate regional transmission planning activities and develop cost allocation methodologies.

FERC's Order 1000, issued in July 2011, further defined and expanded the roles and requirements of transmission planning regions. Transmission planning regions have until October 10, 2012, to comply with new

iii. FERC does not have regulatory authority over the activities of municipal power providers, rural electric cooperatives, or federal power agencies such as the Tennessee Valley Authority or Bonneville Power Administration.

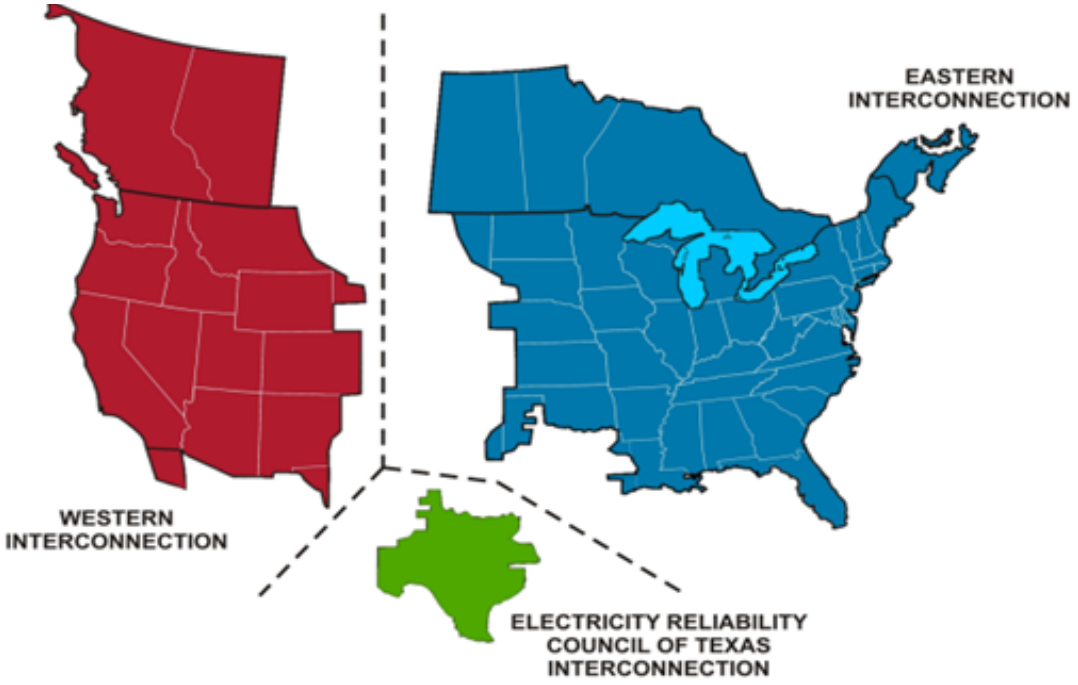
regional planning and cost allocation requirements and an additional six months to comply with new requirements around interregional coordination. States can use the Order 1000 compliance effort to ensure that their energy policy goals are integrated into regional transmission planning.[iv]

The 2005 Energy Policy Act authorized FERC to offer transmission providers rate incentives to promote new transmission development. Utilities or other transmission developers can submit requests for financial incentives to FERC during their rate filing. Incentives include additional basis points on developers' return on equity, full cost recovery for pre-construction costs or construction work in progress, and accelerated depreciation.[10] Many FERC rate incentive approvals are contingent on the proposed lines in a regional transmission plan.

iv. More information on FERC Order 1000 can be found in the "State Strategies to Accelerate Expansion of the Transmission Grid" section of this Issue Brief.

Federal Resource Management Agencies. The federal government also plays a role in transmission development by issuing permits for lines that cross federal lands or waters. In the western United States, approximately 53 percent of land area is federally owned. The federal government owns more than 83 percent of the land area in **Nevada**, the highest percentage of any state.[11] Federal lands in the West are owned and/or managed by a variety of federal agencies, including the Bureau of Land Management (BLM) and U.S. Fish and Wildlife Service within the U.S. Department of the Interior (DOI); U.S. Army Corps of Engineers; U.S. Forest Service; U.S. Department of Defense (DoD); and U.S. Department of Energy (DOE). The Bureau of Ocean Energy Management, also within DOI, has jurisdiction over offshore resources in the Outer Continental Shelf, including transmission facilities. Offshore wind facilities in the Great Lakes region may require permitting from the Army Corps of Engineers.

Figure 3. U.S. Electricity Interconnections[12]



Regional Divisions

Although states have the power to regulate utilities, the flow of electricity does not stop at the state border. The United States is split into various divisions and subdivisions for the purpose of fostering electricity markets, organizing transmission planning activities, and ensuring regional reliability. The divisions include the three U.S. interconnections and the planning regions recognized by FERC, which include RTOs and ISOs.

Figure 4. FERC Transmission Planning Regions[13]

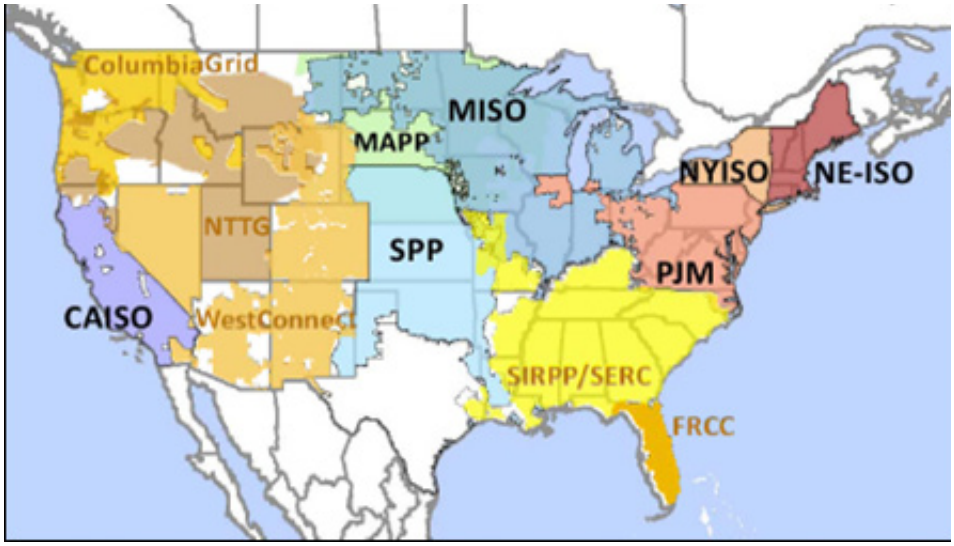


Figure 5. ISOs and RTOs in North America[14]

Interconnections. The U.S. electricity system is divided into three major transmission and distribution grids: the Eastern Interconnection, the Western Interconnection, and Texas (the Electric Reliability Council of Texas [ERCOT] territory), with very little power transferred among them. The divisions among the three interconnections are shown in **Figure 3**.

Planning Regions, ISOs, and RTOs. The United States is currently divided into 12 transmission planning regions to comply with FERC Order 890 (**Figure 4**). In six of those regions, ISOs and RTOs fulfill that function (**Figure 5**). ISOs and RTOs have very similar functions and responsibilities: both are independent managers and operators of a multi-utility electric transmission grid. However, compared to ISOs, RTOs have greater responsibility over grid reliability and interstate electricity markets. Utilities voluntarily join ISOs or RTOs.

FERC encourages, but does not require, the formation of RTOs or ISOs to achieve compliance with Order 890. There are currently three established ISOs: California ISO, ERCOT, and New York ISO. There are also four RTOs: ISO New England (ISO-NE), Midwest Independent Transmission System Operator (MISO), PJM Interconnection, and Southwest Power Pool (SPP).[v] ERCOT is considered an ISO by FERC but is not subject to FERC planning requirements because it does not manage interstate electricity sales. Even if they have not joined an RTO or ISO, utilities are still required to comply with FERC Order 890 and have created less formal organizations to accomplish this task. Planning regions also will be responsible for complying with FERC Order 1000.

Transmission Providers

Approximately 500 private and public entities own transmission facilities in the United States. Transmission providers fall into three categories: investor-owned utilities, rural cooperatives and public power entities, and merchant transmission providers.

Investor-Owned Utilities. Regulated, investor-owned utilities own 66 percent of the transmission assets in the continental United States.[15] These utilities include both vertically integrated utilities (that may own both generation and transmission) and utilities in restructured markets (that may only own transmission and/or distribution assets). Utilities can recover the costs of new transmission lines through FERC-approved transmission tariffs and ultimately through their electricity rates, approved by state public utility commissions.[vi] Transmission costs average between 5 percent and 7.5 percent of a customer's monthly bill.[16,17]

Rural Cooperatives and Public Power Entities. Rural electric cooperatives and public power districts also own and operate transmission for their customers. Cooperative and public power transmission ownership accounts for 27 percent of total U.S. transmission. These types of ownership are more common in the West and Great Plains, at 42 percent and 49 percent, respectively.[18] Although their rates are not regulated by public utility commissions, cooperative and public power transmission facilities are subject to the same state siting requirements as investor-owned utilities. Public power districts and rural cooperatives are not required to take part in regional transmission planning initiatives but often participate voluntarily.

Merchant Transmission Providers. The restructuring of the electric power industry that began in the 1990s has allowed a new type of transmission owner to enter the market: merchant transmission providers. These private companies finance and own transmission facilities independent of generation developers or customer-serving utilities. Unlike utilities, merchant transmission providers must take on the financial responsibility and risk associated with building new transmission lines, recouping costs through access charges paid by generators and/or load-serving utilities. Merchant providers only own around 4 percent

v. MISO and ISO-NE continue to use "ISO" in their name despite their designation as RTOs

vi. Transmission costs are subject to FERC jurisdiction and essentially a pass-through to load-serving entities. States do not have authority to prevent utilities from recovering those costs in rates but can determine how costs are allocated across customer classes.

Figure 6. Existing High-Voltage Transmission System[21]

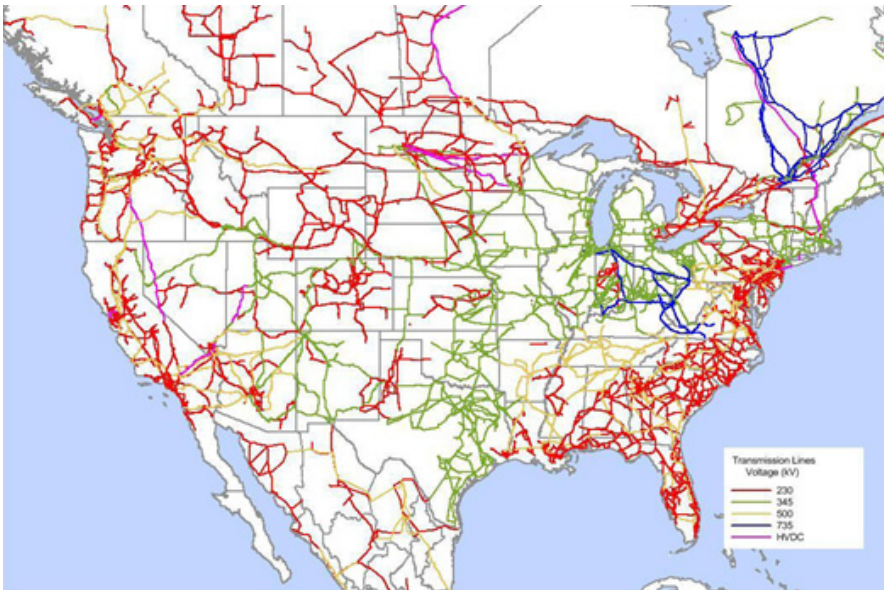


Figure 7. Proposed New High-Voltage Transmission Lines[22]

of high-voltage transmission capacity.[19] Thus far, merchant providers have been most active in the Great Plains and Midwest, although there are examples of merchant transmission lines across all regions. A merchant company also has proposed a backbone undersea line to link future offshore wind resources in the Atlantic Ocean before connecting to load centers on the East Coast.

Demand for Renewable Energy Resources Affects the Transmission Grid

Currently, the U.S. electric transmission grid is strained. Modernization and expansion are needed to address future demand, enhance reliability, and integrate new resources, especially renewable energy.[20] According to the North American Electric Reliability Corporation

(NERC), new transmission additions are expected to increase to 3,100 miles per year between 2009 and 2018 compared with 1,000 miles per year between 2000 and 2008.[23] The broader growth picture, comparing existing high-voltage transmission lines to the proposed new high-voltage lines, is illustrated in **Figures 6** and **7**.

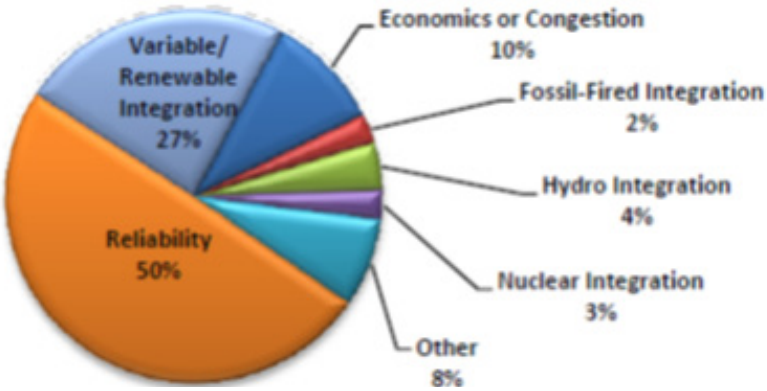
Non-hydropower renewables account for slightly more than 5 percent of total U.S. electric generation capacity.[24] But policies at the state level are driving the demand for additional electricity generation from renewable resources that in turn creates a demand for new transmission lines. State renewable portfolio standards (RPS) policies are the most widely used mechanisms to bring renewable energy to the market. Thirty states and territories currently have some form of mandatory RPS and another eight states have a nonbinding statewide goal for renewable energy consumption. A study by the Lawrence Berkeley National Laboratory estimated that, of the 37 GW of new renewable capacity added between 1998 and 2009, 23 GW (61 percent) can be attributed to state RPS requirements. The same study predicted that RPS policies are expected to spur the development of an additional 50 GW of new capacity by 2025.[25] Although the 37 GW of renewable energy capacity added between 1998 and 2009 constituted slightly less than 13 percent of capacity additions from all sources during that time, under current projections renewable resources would make up roughly half of the 86 GW of new capacity added by 2025.

In the short term, continued growth in the generation of electricity from renewable resources remains a primary driver for new transmission capacity. Roughly 27 percent of currently planned transmission projects propose to integrate renewable resources.[26] By 2020, 80 percent of new generation capacity additions are projected to be from renewables. Future, higher RPS targets may prompt additional renewable energy and transmission needs. Regardless, the next decade is a critical period for addressing transmission needs to meet current RPS targets, which typically extend to 2020 or 2025.

Additional renewable energy demand is not the only factor driving the need for new transmission. Seventy percent of transmission lines are at least 25 years old—much of the transmission grid was designed in the 1950s and installed in the 1960s and 1970s.[27] At the same time, low-cost natural gas developed from shale formations, the age of the U.S. coal-fired generation fleet, and new U.S. Environmental Protection Agency regulations for power plants are predicted to push changes in the electric generation fleet as a whole, particularly as natural gas becomes the fuel of choice for new fossil-fired generating capacity.

In 2009, investor-owned transmission companies and state power authorities in **New York** initiated a study to assess the long-term reliability and economic impacts of various transmission expansion and retirement plans. Rather than assuming retiring transmission capacity would be replaced with equivalent new infrastructure,

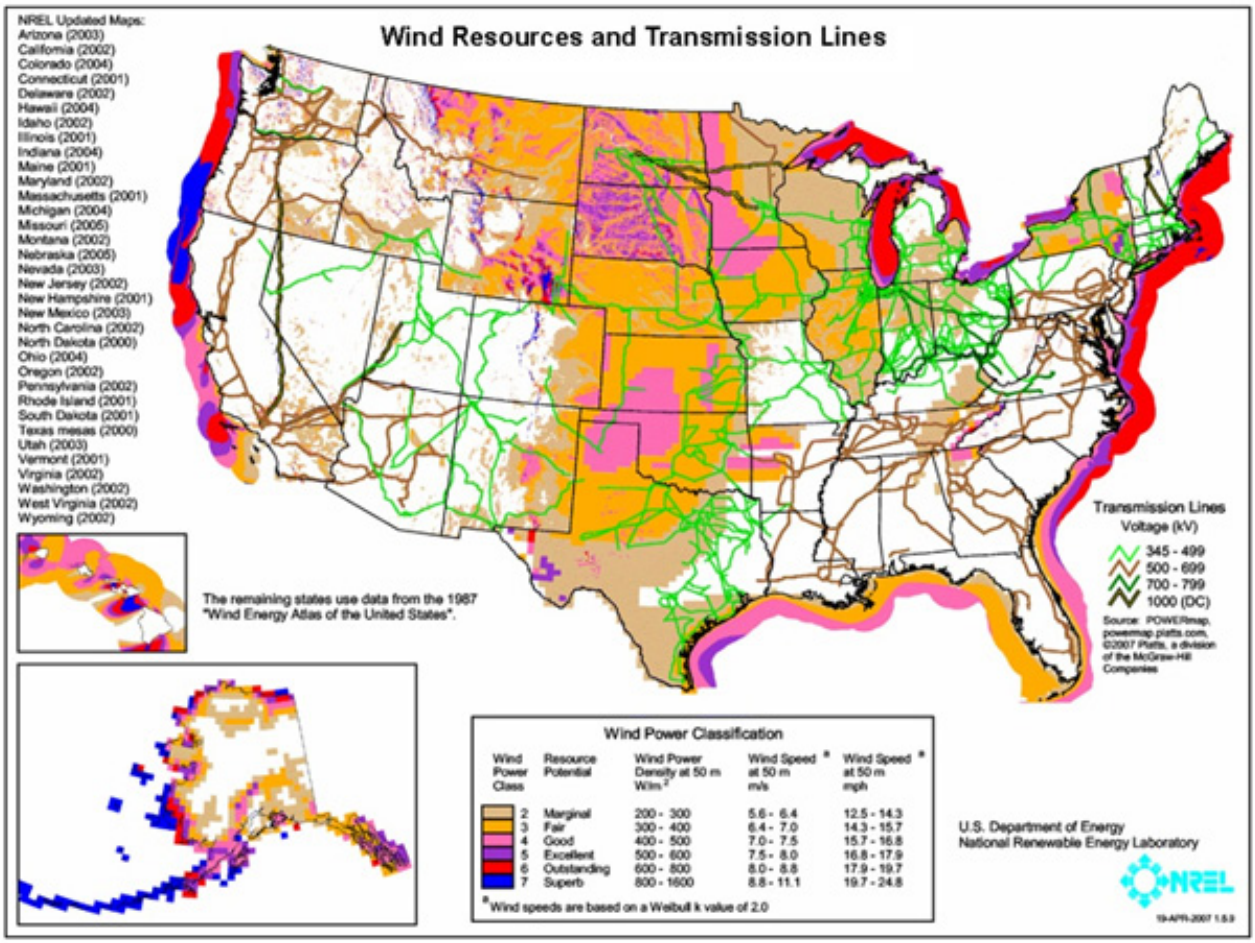
Figure 8. Planned Transmission Capacity Additions by Primary Driver[28]



the Strategic Transmission Assessment and Reliability Study (STARS) initiative considered various alternatives for upgrading, refurbishing and building new transmission in New York to replace aging infrastructure, support the cost-effective integration of renewables, and improve the economic efficiency of the New York power grid.

Although maintaining the reliability of the electric grid will continue to be a priority for transmission providers, the second largest driver for boosting transmission capacity will be the integration of renewable energy into the system, more so than integrating new fossil fuel-fired generation (**Figure 8**).

Figure 9. Wind Resources and Transmission Lines (2007)[30]



It should be noted that construction of new transmission is not the only solution for meeting state energy goals. Various non-transmission alternatives can help improve grid reliability, decrease transmission congestion, and/or reduce the cost and environmental impacts of electricity generation. These solutions include energy efficiency and demand response, investments in strategically sited generation facilities, improvements in grid efficiency and performance, and energy storage systems.[29]

No matter how states use these options, they must construct new transmission lines if they also want to integrate new renewable energy resources into the grid. The remoteness of high-capacity renewable energy resources—including some offshore wind power—presents several challenges. The resources are far from demand areas or from the existing high-voltage, high-capacity transmission infrastructure. These issues are particularly acute for wind energy, which currently makes up 39 GW of the 54 GW of installed renewable capacity (**Figure 9**).[31] Continued sizable increases in the capacity of renewable energy resources and the expansion of the transmission grid are strongly linked.

Expansion of the Grid Faces Several Challenges

Building new, high-voltage transmission lines is a complicated, costly, and lengthy effort. For utility-scale renewable generation (e.g., land-based and offshore wind farms, large-scale solar photovoltaic or concentrating solar thermal installations, and geothermal power plants), the issues facing transmission development are further complicated by the remote and constrained location of many high-capacity renewable resources and additional financial and regulatory uncertainty for developers. In some cases, states face unique challenges in adapting existing processes to projects that specifically address the integration of renewable energy.

Planning

Transmission and resource planning is traditionally performed by utilities or independent planners, most often on a regional or sub-regional basis. Planning does not always adequately address coordination of lines that cross regional boundaries. The establishment of ISOs and RTOs has allowed for transmission planning across multi-state regions or across large, single-state grids in **California**, **New York**, and **Texas**. Utilities in non-RTO or -ISO regions are responsible for planning transmission within their service territory, which can cross state boundaries. Regardless, there is not a defined process to plan lines that cross FERC planning regions (**Figure 3**).[32] Examples of areas where transmission lines would need to cross multiple planning area boundaries to connect remote renewable resources include the west and the Great Lakes regions. Increased involvement in transmission planning at the state level will require additional collaboration between gubernatorial administrations, PUCs, and utilities.

Siting and Permitting

The process of siting and permitting transmission lines requires many steps, each of which takes time and is likely to lengthen when a line crosses more than one state or region. Public utility commissions or dedicated state siting authorities must consider a number of factors, including the overall need for a new transmission line, environmental impacts, property rights, and cost. Permitting times for major transmission lines vary by state and by project, but since 1985 have increased from an average of three to four years to as many as 10 years.[33] The Wyoming–Jacksons Ferry line between **Virginia** and **West Virginia**, which required approval from the U.S. Forest Service and from the states involved, spent 13 years in the permitting phase.[34] In contrast, the permitting process for the more recent Trans-Alleghany Interstate Line connecting **Pennsylvania**, **West Virginia**, and **Virginia** took less than two years.[35] NERC's most recent long-term reliability analysis found that a majority of transmission projects were experiencing delays of up to three years and that nearly 6,500 transmission miles were considered "delayed" by regional transmission planners as of the end of 2009.[36] Delays and uncertainty in

the siting process can hinder investment in transmission infrastructure and jeopardize the construction of planned projects.

The length and complexity of siting and permitting are not unique to projects that support renewable energy, but the location constraints of renewable energy further complicate the entire enterprise. Because higher capacity renewable resources, which have a lower generation cost, are not necessarily located in states where the power they produce will be sold, more new transmission will need to cut across state boundaries to connect resources to load. The permitting of transmission lines that cross state boundaries requires separate approval from each of the states involved, although documentation or analyses are often similar for each state siting body. Many states face the additional regulatory hurdle of federal permitting approval for transmission projects. Depending on the number of agencies involved and the size of the project, the federal permitting process could potentially add three years to five years to the time needed to site a new transmission line.[37] That time could be shortened now that DOI has made the development of renewable energy resources on federal land a priority and pledged to engage more effectively with federal agencies responsible for energy and transmission development.

Financing

Financing is a challenge for any large infrastructure project. Securing early financing for transmission projects that integrate renewable energy resources is even more difficult. First, the siting, permitting, and construction of transmission frequently take significantly longer than the siting, permitting, and construction of generation facilities, exacerbating the financing problems.[38] Second, the projects often face a "chicken-or-egg" dilemma: transmission lines have trouble securing financial support without the guarantee of a generation facility, but renewable generation facilities often cannot secure funding without the certainty of transmission to bring the power to market.[39]

As with planning and siting challenges, the remote location of many renewable resources—far from the existing transmission infrastructure—has an impact. Even though the industry credits FERC's rate incentives with helping sustain investment in new transmission facilities, these do not necessarily address all of the financing issues associated with developing new transmission lines.[40]

The Chinook line, a proposed 1,000-mile merchant transmission line to connect wind power from **Montana** to a substation in **Nevada**, illustrates the dilemma sometimes faced by transmission developers. The proposal for the transmission line offered a degree of certainty to potential wind developers, but not enough to facilitate the development of adequate wind resources to justify construction of the line. Without the guarantee of enough electric power to sell over the line, the developer chose not to invest in the cost to secure state permits.[41] TransCanada, the project's developer, asserts that the project is not dead but that there is not sufficient market support for the project to proceed now.

Cost Allocation

Allocating the cost of a new transmission line is a complicated endeavor because it requires agreement among all the parties participating in the construction of the line, the members of a regional electricity market, or with those whose territory is affected by the line crossing. Cost allocation methodologies can include: assigning costs entirely to generators requesting interconnection; a "beneficiary-pays" approach, where cost are allocated in proportion to the benefits that different utilities would receive from the line; a "license-plate" method, where the utility building the line pays all costs; or a "postage-stamp" approach, where all utilities using the line pay equal amounts and spread the costs across jurisdictions. Cost allocation for renewable energy transmission is a challenge because those commonly used approaches may not readily apply. Allocating costs entirely or primarily to generators may make some renewable energy projects

financially impossible. Yet placing the burden solely on end-user customers ignores renewable energy's broader societal benefits, such as reducing emissions. At the same time, spreading the costs evenly across a region may fail to account for why the line was needed in the first place—for instance, to help a specific state meet its RPS or for an energy developer to get its product into the market. The challenge of developing cost allocation methods for renewable energy transmission projects will vary. RTO and ISO regions may adapt established allocation formulas to renewables or may choose to develop new methods to apply only to a sub-class of transmission projects. States and utilities in non-ISO and -RTO regions that divide costs for each project on a case-by-case basis will need to develop a consistent methodology for renewable energy projects, both to provide certainty to developers and to comply with FERC Order 1000.

State Strategies to Accelerate Expansion of the Transmission Grid

States are making progress developing new ways to improve coordination and reduce delays related to transmission grid expansion and have used or could consider the following strategies that hold promise to boost transmission development:

- Participate in existing interconnection-wide planning forums;
- Concurrently plan and site generation and transmission;
- Work with regional partners to coordinate interstate siting;
- Develop partnerships with federal agencies;
- Develop centralized infrastructure to support further expansion;
- Create and utilize infrastructure financing authorities; and
- Develop cost allocation methods that apply to renewable energy projects.

Governors have a key role to play in overcoming those challenges. Even though the siting of individual transmission lines is the task of independent utility regulators, state-level energy policies partly determine how generation resources and transmission will be developed. Those policies are often driven by the governor's office and related agencies, typically working with the state legislatures and utility regulators. In addition, several of the above strategies require gubernatorial approval for statutory changes, encourage gubernatorial participation, or are led by participating governors. It is critical that governors work with their utility regulators to clear the hurdles that impede transmission development and advance solutions that cross state lines by engaging with other governors, regional authorities and federal agencies.

Participate in Existing Interconnection-Wide Planning Forums

States in some regions have traditionally had a smaller role in transmission planning activities than in the siting and permitting process, but there are a number of emerging opportunities for active state participation. FERC Order 1000 provides both an opportunity and a challenge for states and regions attempting to address regional and interregional planning issues. The order requires that all planning regions engage in a formal planning process that produces a transmission plan that includes specific, proposed projects. Previously, some regions completed more theoretical scenario analyses instead of transmission plans. Transmission plans will also be required to consider applicable state policies. For some regions—such as New England, the Mid-Atlantic, and the Midwest—that will not drastically change current planning efforts. In the South and West (excluding **California**), policymakers will need to develop more formal processes for creating transmission plans. Planning regions will also be required to enter agreements with neighboring regions about lines that may cross regional borders.

U.S. DOE is supporting interconnection-wide planning efforts in each of the three U.S. electric interconnections (Eastern, Western, and Texas). Each region will produce a long-term analysis of resource and

transmission needs under a variety of energy supply, demand, and policy scenarios. The first phase of the analysis was completed in 2011, with the second phase scheduled for completion in 2013. In the West and in Texas, those efforts are continuing existing transmission and resource planning exercises. In the Eastern Interconnection, the effort marks the first time an interconnection-wide planning effort has been undertaken for the region. A state planning council and stakeholder steering committee—both with a strong state presence—have been a critical element of the process. Each interconnection is required to develop analyses identifying areas for renewable energy development and their potential transmission needs. States were represented in those efforts by both utility regulators and governors' offices, giving governors' staff an opportunity to participate directly in a process they might not typically be engaged with.

States should use those efforts to better understand and predict the interconnections' long-term transmission needs as renewable energy continues to grow and to facilitate the process of interregional collaboration among regional transmission planners. The interconnection-wide planning efforts will not produce a transmission plan, but will provide states with the information that their planning regions can use to develop future transmission plans and comply with Order 1000. As their regions conduct more formal planning activities, states—and, in particular, governors—should engage in planning efforts and use the lessons learned from the interconnection-wide forums where they can.

Concurrently Plan and Site Generation and Transmission

To reduce the uncertainty faced by investors in renewable energy and transmission, states should consider concurrent planning and siting of renewable energy generation and transmission. Identifying transmission corridors while developing renewable resources can reduce delays and lead to cost-effective outcomes. **California**, **Texas**, and **Utah** have all adopted some form of a coordinated renewable energy and transmission planning process. An effort spearheaded by the Western Governors Association has attempted to do the same on a regional level.

The Competitive Renewable Energy Zone (CREZ) process in **Texas** serves as a successful example of that process. Through the CREZ process, the state identified five areas for the development of renewable energy (primarily wind) and selected seven companies to build the necessary transmission. In all, 2,300 miles of 345 kV transmission lines will be built by 2013, adding more than 18 GW of wind power to the Texas electric grid. Texas's unique position as a statewide, fully deregulated electricity market that is also its own interconnection area may prevent other states from adopting the exact competitive process used to select the participating transmission providers. Nonetheless, the joint planning of renewable energy and transmission at the state, RTO, or interconnection-wide level is a model that could be replicated elsewhere as states see fit.

Work with Regional Partners to Coordinate Interstate Siting

States can expedite the permitting process by establishing processes for coordination among neighboring states when interstate transmission lines are planned. That could reduce the time it takes for new transmission lines to move from concept to construction and cut the overall cost of new lines.

The six New England states—**Connecticut**, **Maine**, **Massachusetts**, **New Hampshire**, **Rhode Island**, and **Vermont**—studied how to streamline the development of transmission in the region, with the specific goal of integrating new renewable energy capacity. In 2009, the governors of those states adopted the *New England Governors' Renewable Energy Blueprint*.[42] The document analyzed and outlined opportunities for the states to engage in joint or concurrent processes around the procurement of renewable energy and the siting of interstate transmission. The states worked

through the New England States Committee on Electricity (NESCOE), the regional state committee that provides collective state input into ISO-NE's planning process. The *Blueprint* identified the potential for interstate coordination, emphasizing activities that could be accomplished under existing state laws, such as:

- Conducting approximately concurrent siting reviews;
- Sharing common application components and testimony among states;
- Issuing coordinated discovery to ensure uniform information and simplify applicants' responses;
- Conducting joint hearings (as long as they do not displace necessary local hearings); and
- Adopting joint or concurrent orders on commonly required findings.

In June 2011, NESCOE announced the formation of an Interstate Transmission Siting Collaborative.[43] That body, with representation from each of the six New England states, will explore coordination opportunities for siting interstate transmission lines in the region. Each state will retain its permitting authority, but the collaborative will work to coordinate mechanisms that ensure that state siting processes for interstate transmission facilities are as efficient as possible.

In 2008, the governors of **Iowa, Minnesota, North Dakota, South Dakota** and **Wisconsin** created the Upper Midwest Transmission Development Initiative (UMTDI) to coordinate transmission planning, siting and cost allocation among those five states. The goal was to overcome barriers preventing renewable energy resources in those states from reaching customers due to a lack of adequate transmission. The UMTDI released a final report in 2010 outlining existing legal structures and impediments to regional cooperation around transmission siting. The UMTDI also developed a set of cost allocation principles, designated renewable energy zones, and identified six priority transmission corridors within the UMTDI region.[44]

The UMTDI report also noted that all five states have the power to create an interstate compact to jointly develop the projects identified in the UMTDI report. The federal Energy Policy Act of 2005 specifically grants states the ability to enter into interstate compacts around the siting of transmission projects but states have yet to do so.

Develop Partnerships with Federal Agencies

States can work closely with federal agencies to ensure that transmission projects that cross federally managed lands or waters are not unduly delayed because of unexpected or overly lengthy federal permitting requirements. **California** has developed a memorandum of understanding (MOU) with DOI to expedite the siting of renewable energy projects—and their associated transmission lines—on federal land that can serve as an example for other states.[45] The MOU, signed in 2009 by former Governor Arnold Schwarzenegger and Secretary of the Interior Ken Salazar, commits the parties to work together to review and approve permits for renewable energy facilities in accordance with state and federal environmental statutes. A Rapid Response Team made up of representatives from the California Energy Commission, California Department of Fish and Game, U.S. Fish and Wildlife Service, and Bureau of Land Management (BLM) accelerates the process. The MOU also establishes guidelines for working with U.S. DoD given that some transmission lines need to cross DoD land. Since the MOU was signed, nearly four GW of renewable electricity, along with sufficient transmission capacity, have been added to the grid, including the first utility-scale solar project sited on federal land.

Nevada developed a similar MOU with the BLM to ensure open communication and collaboration on projects within the state. That agreement allows the State Office of Energy and the BLM to convene discussions with other federal, state and local organizations to work through issues associated with renewable energy development and transmission planning. The process

is less formal than California's, but Nevada has found it to be effective in coordinating state and federal review. In addition to statewide MOUs, DOI and its agencies have the authority to enter into MOUs with individual state agencies on a project-by-project basis.

Develop Centralized Infrastructure to Support Further Expansion

States can provide additional certainty to transmission and energy developers by prioritizing transmission infrastructure that can incorporate and accommodate future energy and transmission development. Projects such as collector systems or backbone transmission lines provide an intermediate step in the transmission grid. Those lines potentially allow separate, remotely located generation facilities (e.g., wind farms or solar generating stations) to connect to load centers without developing separate long-distance transmission lines for each.

Several states seeking to develop renewable energy capacity have started to take that approach. **Michigan** recently gave expedited approval to the construction of a backbone line through the "thumb" of the state that will connect limited existing wind resources and spur future wind energy development in the region. The project involves a 140-mile, 345 kV line with four new substations. It is designed to carry more than the maximum amount of wind energy identified in the region, a total capacity of five GW. The state identified the thumb region as having the highest wind potential and a strong need for transmission capacity. That identification spurred ITC Transmission to propose the backbone line in its transmission plan and seek approval from MISO. Construction of the backbone transmission facility will give wind developers certainty that any future wind energy projects in the region will have adequate transmission capacity to connect to load centers. Individual wind farms will only need to build short-distance lines to connect into the backbone network. That in turn helps the state quickly develop the resources it sees as important to the region's economic future.

Wyoming commissioned a study on how to design and develop a wind collector system to efficiently connect existing and future wind energy resources into the transmission grid.[46] The study provided the state with a variety of design scenarios for radial and networked transmission hubs. The analysis included reliability impacts, cost scenarios, and common elements among the various designs to assist the state in implementation. Understanding the needed infrastructure to develop its wind energy resources will help provide certainty to energy and transmission developers interested in investing in the state.

Another study explored the need for additional natural gas–fired generation or new energy storage facilities to be built in conjunction with new wind generation and transmission facilities to help address the variability of wind energy.[47] The study explored five scenarios for using natural gas-fired generation to address the intermittency of Wyoming-based wind power. Those scenarios varied based on whether the gas-fired plants, the gas storage facilities, or the energy storage facilities were based in Wyoming or in the state most likely to consume Wyoming wind power, **California.** The study found that the cost of using natural gas to help integrate Wyoming's wind power would be anywhere between 5 percent and 19 percent of the total wind project costs, including transmission.

The **New Mexico** Renewable Energy Transmission Authority (NMRETA) enlisted the Los Alamos National Laboratory to evaluate options to export 5,200 MW of renewable generation through investment in and improvements to the existing grid.[48] The evaluation found that exporting large amounts of renewable energy from New Mexico will require the construction of at least one multi-state line while also using existing infrastructure. The plan contemplates creating a collector system in order to gather renewable generation from across the state while adding to the reliability and strength of the overall system. Since the

publication of this study, NMRETA has entered into MOUs with private developers for roughly 35 percent of the projects identified in the study, contingent on the development of a cost allocation method that will provide adequate financial returns to investors.

Create and Utilize Infrastructure Financing Authorities

State infrastructure authorities can assist in the financing of priority energy and transmission projects. Generally, those are quasi-governmental agencies, created by legislation, with the statutory authority to design, construct, own, operate, and/or finance energy infrastructure. That may include generation and transmission, although some states have established authorities that largely or exclusively focus on transmission to integrate renewable resources. State infrastructure authorities are essentially bonding agencies that commonly use state tax-exempt revenue bonds that are repaid by user fees or lease payments associated with the financed transmission line. They can also serve an important role in promoting the development of new transmission infrastructure, even when public financing is not needed. States that currently have infrastructure finance authorities are **Colorado**, **Kansas**, **Idaho**, **Montana**, **New Mexico**, **North Dakota**, **South Dakota**, and **Wyoming.**

The **Kansas** Electric Transmission Authority (KETA) has the authority to plan, finance, construct, and acquire transmission facilities in the state. Although KETA transmission facilities are not limited to those connecting renewable energy sources, the desire to expand wind resources within Kansas was a major driver for the creation of KETA in 2005.[49] KETA's most notable project so far is a line the authority did not finance directly: KETA identified a 210-mile line with portions of both 345 kV and 765 kV between Spearville, Kansas, and Axtell, Nebraska. Among the project's benefits is interconnection of renewable resources. After KETA expressed its intent to develop the line itself, ITC Great Plains, a merchant transmission developer, took over construction of the line. KETA used its authority to submit the line to the regional transmission operator, SPP. SPP approval of the line in its regional transmission plan provided enough certainty for ITC Great Plains to invest without financial assistance from KETA.[50]

In **New Mexico,** NMRETA is specifically authorized to provide financial assistance to transmission projects that incorporate renewables. In November 2010, NMRETA issued $50 million in revenue bonds to expand a high-voltage transmission line between the High Lonesome Mesa wind farm and a substation on the state's western border. The proceeds from the bond issuance were loaned to the private wind farm developer, who is using them to upgrade the transmission link, allowing the wind farm to operate at a higher capacity. NMRETA will not take ownership of the existing facility, which is owned by a New Mexico utility. The sale of the additional power from High Lonesome Mesa to Arizona Public Service will be used to repay NMRETA, which in turn will repay bondholders using the collected revenue. State resources will not be used to secure or repay the bond.

Develop Cost Allocation Methods that Apply to Renewable Energy Projects

States will need to work at the regional level to develop and adopt cost allocation methodologies to apply specifically to transmission projects for remotely-located renewable energy. While the exact methodologies will differ, it is important that states develop a process for finding agreement around cost allocation at the regional level. FERC Order 1000 places new requirements on planning regions to establish cost allocation methodologies that meet several criteria. Principal among those is that the costs of new transmission facilities be apportioned to states and ratepayers "roughly commensurate" to the benefits they will receive from the new transmission line. That standard stems from a 2009 court decision regarding a cost allocation methodology established by the PJM, an Eastern Interconnection RTO, for new transmission lines greater than 500 kV.[51] The challenge will be in how states in a planning region choose

to define and quantify the benefits of new transmission, particularly lines dedicated to renewable energy projects. The details and formulas will vary among regions, such as how broadly to spread the costs and how to divide the expenses among generators and customers.

The states in the MISO territory—**Illinois**, **Indiana**, **Iowa**, **Kentucky**, **Michigan**, **Minnesota**, **Missouri**, **Montana**, **North Dakota**, **Ohio**, **South Dakota**, and **Wisconsin**—helped develop a new cost allocation methodology to apply to transmission projects that officials believed benefited the entire region, including the integration of renewable energy resources. The new cost allocation method creates a new class of transmission projects—Multi-Value Projects (MVPs)—whose costs are spread by a usage charge across customers in the MISO jurisdiction and some export customers. That is different from the approach MISO takes with transmission projects for ensuring reliability.[52] Representatives from each of the involved states, through their regional state committee (the Organization of MISO States) and through direct interaction with MISO contributed to the stakeholder process. That culminated in MISO filing the MVP cost allocation with FERC, who approved the filing in December, 2010. MISO officials believe MVP designation meets the requirements of FERC Order 1000 and the "roughly commensurate" standard set by the court. Not all of the MISO states approve of the outcome produced, citing concerns about attribution of benefits, and therefore the allocation of costs, to states within MISO far removed from the project. The stakeholder-driven process can be duplicated in other regions even if the outcomes will be different.

In addition to the new formula for cost allocation, MISO is taking a different approach to how the lines are being considered for cost allocation in the transmission plan. The first set of MVP projects was submitted to the MISO board of directors in December, 2011. At that time, the board did not consider each line individually, but looked at a portfolio of 17 lines.[53] Because the lines as a group provide broad regional reliability and renewable integration benefits, the business case for the portfolio calls for the costs to be pooled and allocated across all MISO states using the MVP formula. MISO's analysis has found that the benefit–cost ratios for each of the states were positive and relatively equal, ranging from 1.8 to 1 to 3 to 1.

SPP—containing all or part of **Arkansas**, **Kansas**, **Louisiana**, **Missouri**, **Nebraska**, **New Mexico**, **Oklahoma**, and **Texas**—approved a regional cost allocation method as part of its Integrated Transmission Planning Process.[54] The new methodology splits transmission projects into two categories: "highway" projects (300 kV and above) or "byway" projects (below 300 kV). The cost of highway projects, which are more likely to connect renewable resources due to their higher voltage, will be divided among transmission owners across the region based on their historic use of the system. Byway project costs will be allocated more directly to the utility using the line. As with the MISO MVP methodology, the highway/byway delineation was approved by the SPP Regional State Committee, giving states a say in the methodology.

Looking Ahead

The next several years will present new challenges and opportunities for states to accelerate transmission development for renewable resources. The requirements imposed by FERC Order 1000 could lead to a new way of planning for, and allocating the costs of, transmission. At the same time, the results of the interconnection-wide planning exercises are expected to provide insight into how the transmission grid will need to look if state renewable energy goals are to be met. They can also serve as a roadmap for regional and interregional transmission planning. Both compliance filings for Order 1000 and the interconnection-wide planning efforts will provide additional clarity and certainty for transmission developers, but will require increased interstate

coordination around planning, siting, and cost allocation to be implemented successfully. Governors will continue to play an important role in the process by engaging with their own utility commissions, with the public, and with each other to ensure that new transmission capacity is constructed in an efficient, timely and equitable manner.

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