NASEO
National Association of
State Energy Officials

Managing the Grid: A Deep Dive into the United States Electric Transmission System for State Energy Offices

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Executive Summary

State and Territory Energy Offices (henceforth State Energy Offices) play a crucial and expanding role in transmission planning, which is essential for a reliable, affordable, and sustainable electric power sector. While there are many reasons to expand the United States transmission system, planning and siting transmission facilities[1] remains challenging. Both federal and state governments have distinct and, in some areas, overlapping responsibilities. State Energy Offices provide vital energy and policy expertise that informs the efforts of Governors' offices, state legislatures, public utility commissions, and environmental agencies. Additionally, they support public stakeholder processes by engaging local communities and businesses and foster regional and cross-state collaborations.

To perform these transmission planning support functions, State Energy Offices must understand how the transmission system works, and how it fits into the electricity system and markets, state policy set by governors and legislatures, regulatory structures, and federal and state transmission planning processes.

This document provides an overview of the transmission system for State Energy Offices and identifies additional resources State Energy Offices may want to consider to enhance their expertise. The document includes the following parts:

- Section I provides an introduction into the topic;
- Section II describes the key engineering and economic characteristics of the electric power grid, transmission's role, generation mix, and costs;
- Section III discusses the federal legal, policy, and regulatory contexts;
- Section IV highlights the need for transmission investment, federal and state transmission planning processes, and non-transmission alternatives;
- Section V details transmission and related electricity market issues by region and their implications for states; and
- Section VI provides a conclusion.

Essential references are listed and annotated for further information at the end, along with a list of abbreviations.

I. Introduction

A reliable and affordable electric power sector requires large-scale transmission. In North America, electricity is transmitted from generators to retail customers via hundreds of thousands of miles of transmission lines. Transmission provides a vital connection between supply and demand of electricity, which must always be balanced. Electricity can be transmitted efficiently and at relatively low costs at high voltages over long distances. Increasing business and consumer demand, along with recent U.S. federal legislation and regulatory decisions, are driving the need to substantially and more rapidly expand the U.S. transmission system to support economic development by meeting the growing demand for electricity for data centers and manufacturing as well as transportation and building electrification, while providing affordable, reliable electricity nationwide. Transmission is also instrumental in economically developing large-scale clean energy resources, such as onshore and offshore wind facilities and solar projects, by integrating the variable electricity generation across large geographies and time zones. Moreover, transmission facilities can improve reliability and resiliency and reduce congestion that would otherwise raise electricity costs.

The United States has more than 7,300 power plants, 160,000 miles of high-voltage transmission lines, and millions of miles of low-voltage power lines.[2] While the vast majority of high-voltage transmission lines use alternating current (AC), about 2% are direct current (HVDC) lines.[3] Generation interconnection, the process by which new generators are integrated into the existing grid, requires transmission studies to ensure that a new facility's operation does not cause reliability issues, such as excessive power flows over existing transmission lines, and that it does not adversely impact the operations of existing generation units due to how alternating current (AC) power flows on the grid. With such a large transmission infrastructure built over a century, the replacement of aging infrastructure is required. Approximately 70% of U.S. transmission lines and transformers are 25 years or older,[4] and much of today's grid was built in the 1960s and 1970s.[5]

Building new transmission facilities is challenging because of the complex planning, siting, and cost allocation processes that involve many private and public stakeholders. New transmission facilities can take between ten to fifteen years to complete, if they are finished at all. They can have substantial environmental impacts and raise community concerns over siting due to the appearance of the lines and towers. The build-out and implementation of grid-connected and distributed generation, energy storage, new transmission technologies, and demand-side management programs may increase or decrease the need for large-scale transmission lines and substations.

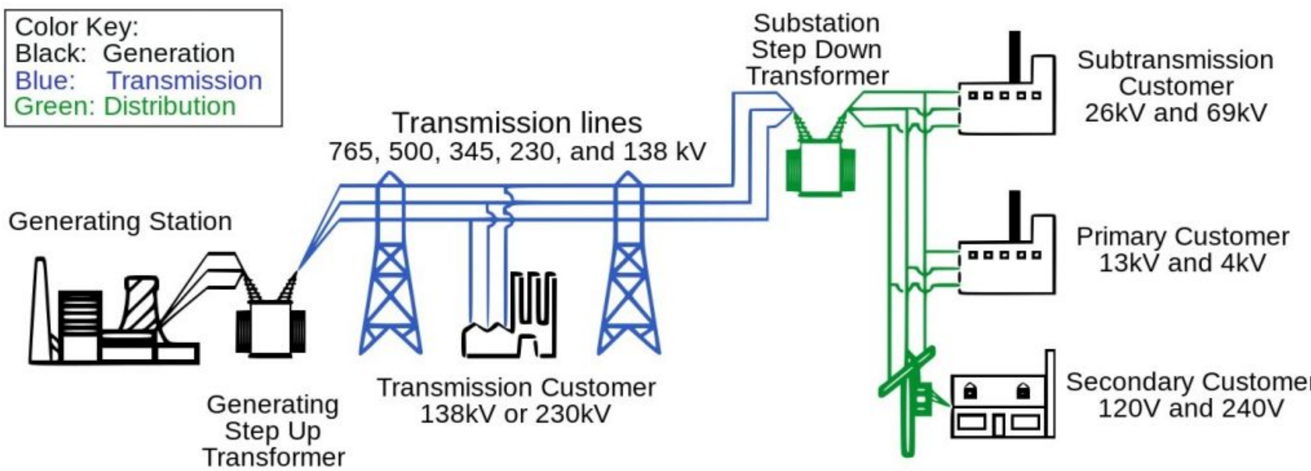
Finally, transmission issues are tightly coupled with wholesale electricity markets. To be effective, transmission policies and planning need to account for wholesale market structures. This is complicated by the variations in wholesale market structures across the country. Understanding these complexities is crucial for State Energy Offices to develop robust and adaptive strategies for managing the grid.

II. Transmission's Role and Its Importance in the North American Electric System

A. Transmission and the Overall Power System

The continental U.S. transmission system transmits electricity from generators to retail customers. It enables the real-time balancing of supply and demand of electricity, which is necessary for the reliability of the system. Figure 1 depicts a basic one-line diagram of the power system. Transmission customers can include utilities, municipalities, and some large industrial users that consume relatively high voltages taken directly from the transmission system, whereas subtransmission, primary, and secondary customers take power from the distribution system.

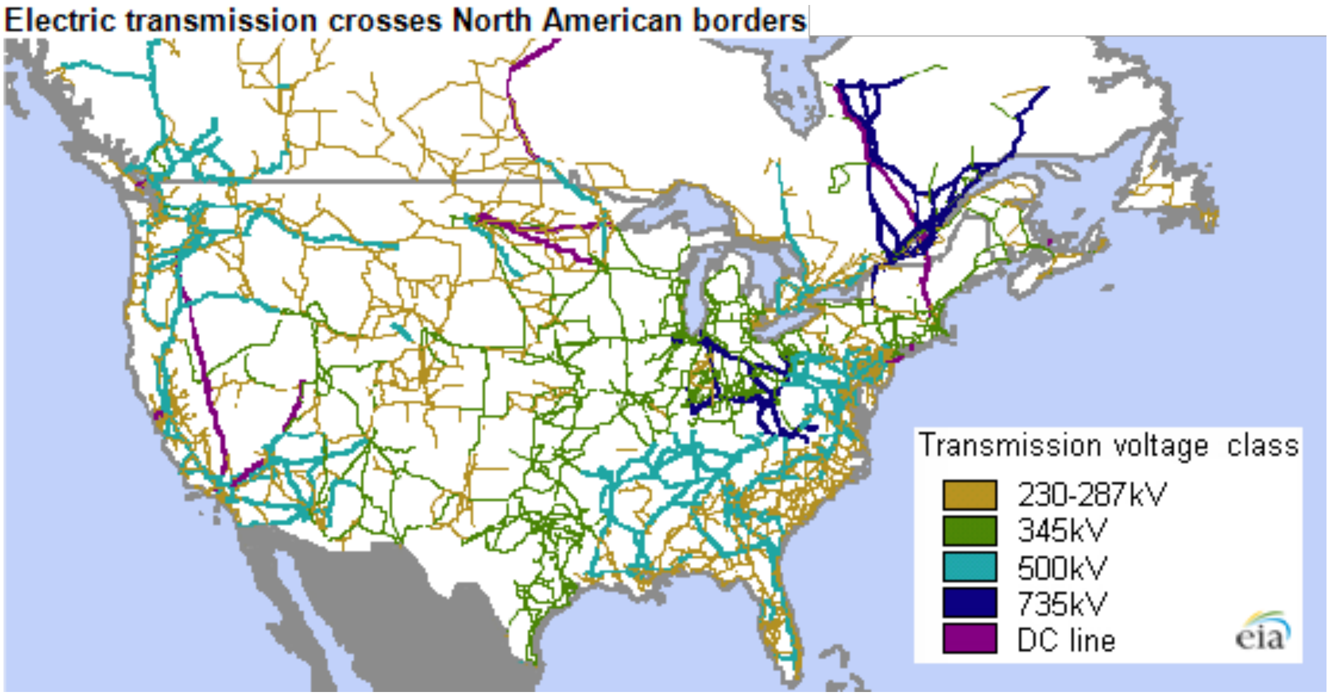
Figure 1. Power System Diagram[6]



Transmission is generally defined as equipment that operates at 100 kilovolts (kV) and above to transmit electricity from generators to distribution networks.[7] It includes transmission lines, transformers, circuit breakers, capacitor banks, and associated equipment. By operating at high voltages, large amounts of electricity can be transmitted long distances with small electrical losses. This efficiency is exemplified by the fact that one 765 kV line requiring a 200-foot-wide right-of-way can transmit the same amount of power as 15 double circuit 138 kV lines that require a right-of-way of 1,500 feet to accommodate the additional infrastructure.[8]

The North American transmission system includes significant interconnections and electricity transfers with Canada (see Figure 2). Sometimes, transmission is referred to as intra- and interregional, with the regional entity being the Regional Transmission Organization/Independent System Operator (RTO/ISO), or in the case of the western or southeastern United States, a transmission planning region designated by the Federal Energy Regulatory Commission (FERC). The roles and responsibilities of the RTO/ISO are discussed in *Section V, Regional Transmission Issues and Their Implications for States*.

Figure 2. North American Electric Transmission Map[9]



As indicated in the above figure, almost all high-voltage transmission is alternating current (AC) rather than direct current (DC). AC power allows for very high voltages, enabling the transfer of electricity over long distances with minimal losses. A consequence of AC power is that it flows from generation to load (end user) across multiple lines, referred to as 'loop flow,' 'parallel flow,' or 'unscheduled flow,' based upon the physical characteristics of the grid. Because these loop flows can span multiple states and regions, impacting their generation and transmission planning and operations, they have significant implications for transmission policy. Therefore, with AC power, the generation and transmission of electricity in one state can have significant consequences for the generation and transmission of electricity in other states, even those geographically distant.

DC power does not have the loop flow characteristic of AC power. However, its engineering and cost characteristics over the one hundred or so years that the U.S. grid was built were less preferable than an AC system. Today, high-voltage DC (HVDC) transmission lines are used in applications such as the ultra-long-distance transmission of power between Canada and the Northeast, offshore wind, and ties between or within major electricity grids. Below, the roles of emerging transmission technologies and DC are further discussed.

Figure 3 is a simplified representation of North America's Northeastern grid portion. It illustrates the multiple transmission paths between nodes or locations in the system, which result in loop flows. Nodes are points of major interconnections between power plants, transmission customers, or distribution utilities and the transmission system. As discussed further below, RTOs/ISOs set wholesale prices for electricity that vary by node (also referred to as 'locations'), and these price differences indicate the amount of congestion in the transmission system. These prices also vary over time.

Figure 3. A Portion of North America's Grid in the Northeast with Nodes[10]

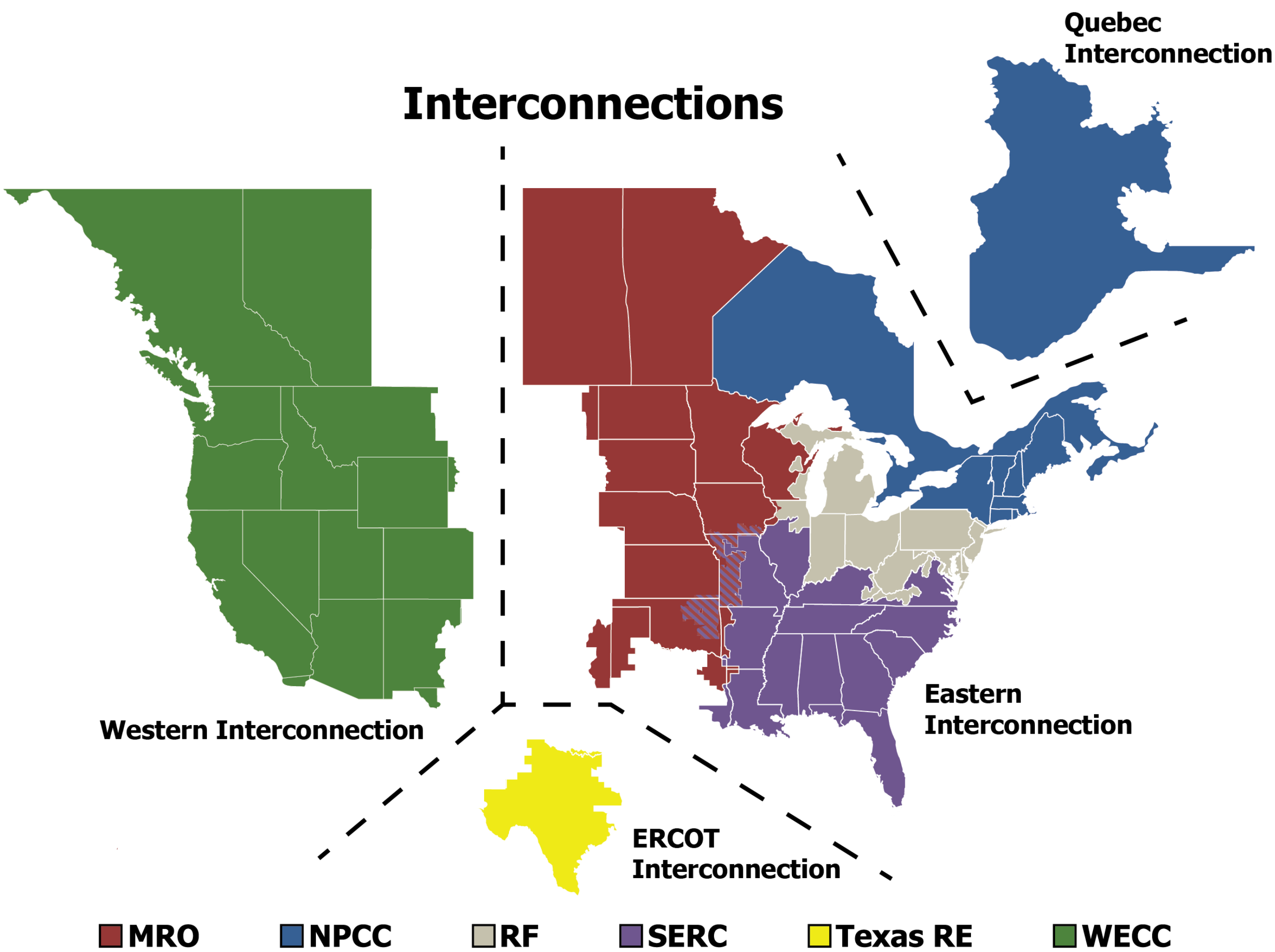
Key Fact #1: The U.S. high-voltage AC power system transfers large amounts of electricity over long distances and multiple paths to instantaneously balance supply and demand to ensure reliability.

Policy Implication #1: The interconnectedness of the U.S. power system means that the generation, transmission planning, and operational decisions in one state can have significant consequences for those in other states.

The North American bulk power system (BPS) is comprised of four major electricity interconnections: Eastern, Western, the Electric Reliability Council of Texas (ERCOT), and Québec, as depicted in Figure 4. Within each, AC power flow is synchronized so that the operation of generation units in one part of the grid is affected by the operation of units in another part of the same grid. Between grids, DC tie lines allow for power flows from one grid to another and for separate or nonsynchronous operations within each grid.

The North American Electric Reliability Corporation (NERC) is a not-for-profit, international regulatory authority authorized by the United States and Canadian governments to ensure the North American BPS reliability. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC oversees six Regional Entities and encompasses all the interconnected power systems of Canada and the contiguous United States, as well as a portion of Mexico. Alaska's grid operates separately and independently from the BPS and is not under NERC's jurisdiction.

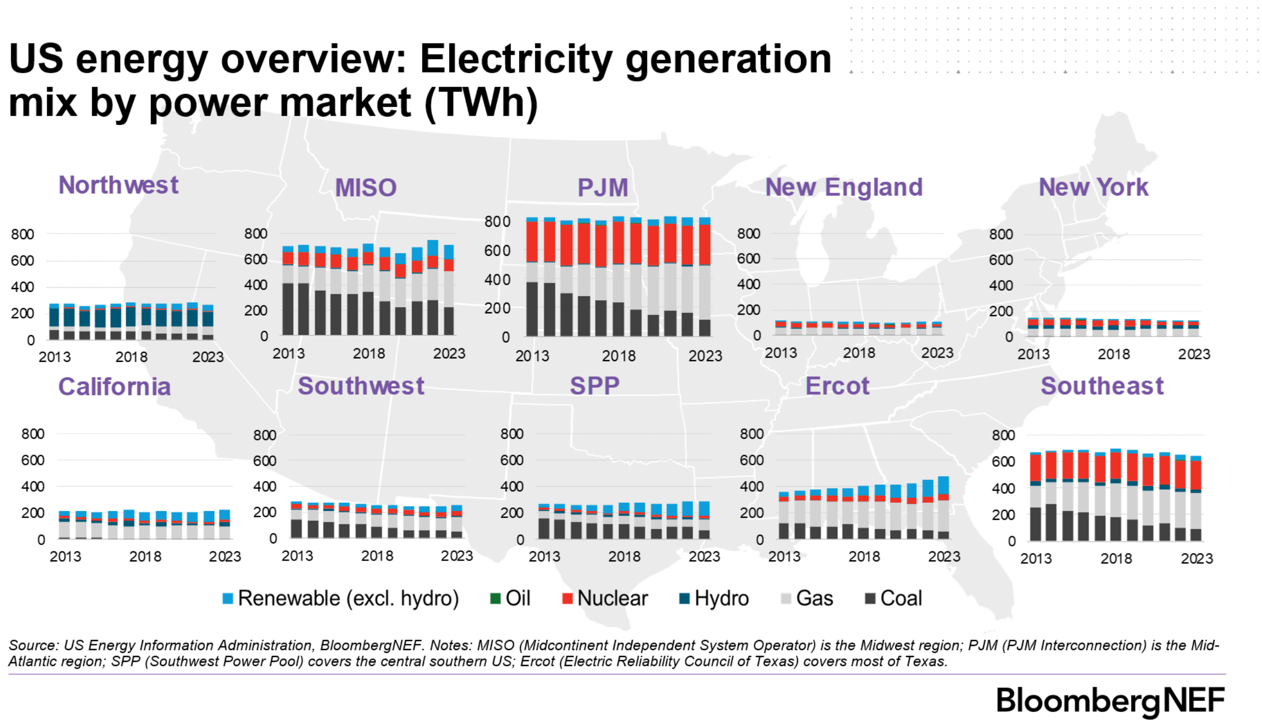
Figure 4. The Grids of the North American Power System and NERC Regional Councils[11]



B. Transmission and Generation Mix

Transmission integrates electricity generation from many types of power plants. Power plants vary by the fuel used and their operating characteristics. The U.S. generation fuel mix includes coal, natural gas, nuclear, hydroelectric, geothermal, wind, solar, and oil. Figure 5 shows the 2012 and 2023 capacity resource mix by interconnection.

Figure 5. Electric Generation Mix by Power Market: 2013, 2018, and 2023[12]



The capacity factor, the percentage of a year that a generation unit produces at equivalent full output, varies for different fuels. Nuclear power plants have the highest capacity factors, at slightly over 90%, although their total capacity (i.e., their size) is only 10% of the U.S. system. Coal has the second-highest capacity factor, at around 70%-80%, and the largest capacity, although its share is declining. The capacity and the output of wind and solar are increasing but are still low compared to other fuel types. The capacity factors for onshore wind, offshore wind, and solar are roughly 30%, 40%, and 20%, respectively.

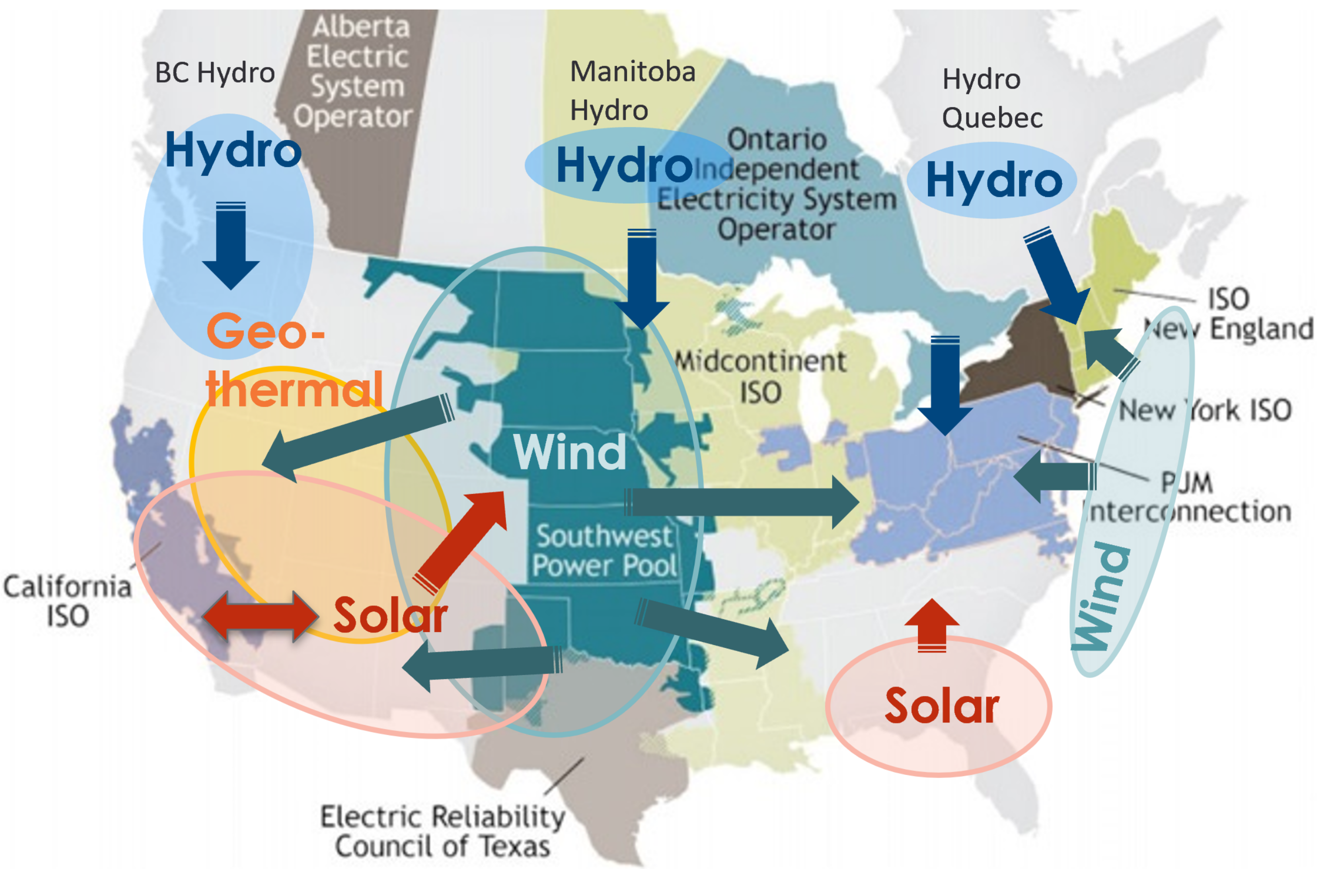
In general, capacity factors reflect the underlying economics and operational strategy of a given power plant. Plants with higher capacity factors – such as nuclear or combined-cycle natural gas facilities – are typically designed to operate continuously and maximize output over time, making efficient use of their upfront capital investment.

In contrast, wind, solar, and many hydroelectric facilities have lower capacity factors relative to their capital intensity, since wind, sunlight, and water are not always available. Although the fuel for wind and solar is free, these plants generate electricity less consistently, leading to lower capacity factors.

Baseload units, such as nuclear, coal, and some natural gas combined-cycle units, are designed and operated to produce electricity around the clock, except during maintenance. Intermediate units, also known as peakers, usually follow demand and run during workdays, given the higher electricity demand during this time. Many natural gas combined-cycle units provide electricity as intermediate units since they can easily ramp up and down. Peaking units run very few hours in a year, usually during periods of very high electricity demand and emergencies. They tend to be costly to operate and are mostly natural gas- or petroleum-fueled internal combustion engine or combustion turbine generators.[13]

The regional mix of generation varies substantially from the overall U.S. mix. Figure 6 illustrates the emerging regional mix of renewable resources in North America. For instance, there is considerably more hydroelectric power in the Northwest than in most of the rest of the country. Nuclear power (although not shown in the figure) plays an outsized role in the Northeast compared to other regions. The Midwest leads in the production of wind power. Transmission enables the integration of diverse generation mixes within and across regions reliably and economically by managing the variability of the energy mix and available resources across large regions. As noted previously, the supply and demand for electricity must be balanced instantaneously.

Figure 6. Variations of Renewable Resources in North America[14]



Another important characteristic of power plants is whether they are dispatchable. Wind, solar, and run-of-river hydroelectric generation are variable and non-dispatchable, i.e., their output varies with the weather and cannot be adjusted to changes in demand and supply.

The ability to integrate the production of these variable and non-dispatchable resources over large regions leverages the fact that wind and solar, for example, produce different amounts of power in different regions simultaneously. As a result of this diversification, variable generation combined with transmission improves the ability of the power system to balance supply and demand. Transmission is not the only response to this variability issue but is an integral part of the solution.

> *Key Fact #2: The mix of U.S. generation varies by region, fuel type, operating characteristics, and dispatchability, and the transmission system enables this generation to be integrated over large regions reliably and economically.*
>
> *Policy Implication #2: As more variable resources are added to the generation mix, the transmission system must expand its ability to transmit electricity and integrate other technologies, such as energy storage and load response, to match supply and demand reliably and economically.*

III. Federal Context

Historically, the overriding goal of federal transmission regulation was maintaining reliability at the least cost. New objectives in grid planning are emerging, beyond the traditional ones of providing a safe, reliable, and affordable service. These additional objectives include strengthening resilience to withstand and recover from disruptions, and accommodating increases in demand from manufacturing, data centers and other large sources of load. In addition, 24 states and the District of Columbia aim to decarbonize the electric power system by rapidly increasing the share of clean energy resources. This may include carbon capture for fossil fuels, development of advanced nuclear power plants, and renewable resources such as geothermal, hydropower, wind, and solar. Simultaneously, most states are seeing significant growth in electricity demand from data centers, new manufacturing, and beneficial electrification. The increase in demand, coupled with some state and to an extent federal policy direction, requires substantial new generation interconnections and enhanced transmission (e.g., advanced conductors) or new transmission facilities. As physical and cyber-attacks and severe weather events have increased, the resilience of the electricity system is also an increased focus of state and federal policies and regulations.

The Federal Water Power Act of 1920, later renamed the Federal Power Act (FPA), sets the jurisdictional framework between the federal government and the states concerning generation, transmission, and distribution. The federal government regulates the interstate sale of electricity and transmission via the Federal Energy Regulatory Commission (FERC). With respect to electricity, FERC approves wholesale electricity and transmission rates in interstate commerce for jurisdictional utilities, power marketers, power pools, power exchanges, and ISOs.[15] States have jurisdiction over transmission siting, generation, and distribution by investor-owned utilities and exercise it via state entities. These entities include state public utility commissions (PUCs) or public service commissions (PSCs), State Energy Offices, and siting authorities, depending on the state.[16] However, municipal utilities and rural cooperatives operate with significant autonomy due to limited state governmental oversight.

The Energy Policy Act 2005 (EPAct), among other items, granted more authority to FERC regarding transmission approvals. It established the concept of transmission corridors and, under certain conditions, the ability of FERC to accelerate transmission development. The U.S. Department of Energy (DOE) plays a role in defining transmission corridors by conducting the necessary studies to establish them.[17]

The Infrastructure Investment and Jobs Act (IIJA) of 2021 has played a significant role in transmission. The IIJA, among its many parts, contains a provision that grants FERC authority to supersede state siting decisions in specific instances, allocates significant funding to increase nuclear and hydroelectric power sources, improves the resilience of the grid, replaces, enhances, or facilitates electrical transmission lines, and funds electric vehicle infrastructure and battery processing. The IIJA also encourages additional transmission development through federal funding (e.g., through the Grid Resilience and Innovation Partnerships Program). Table 1 summarizes major federal transmission-related legislation over the last decades.

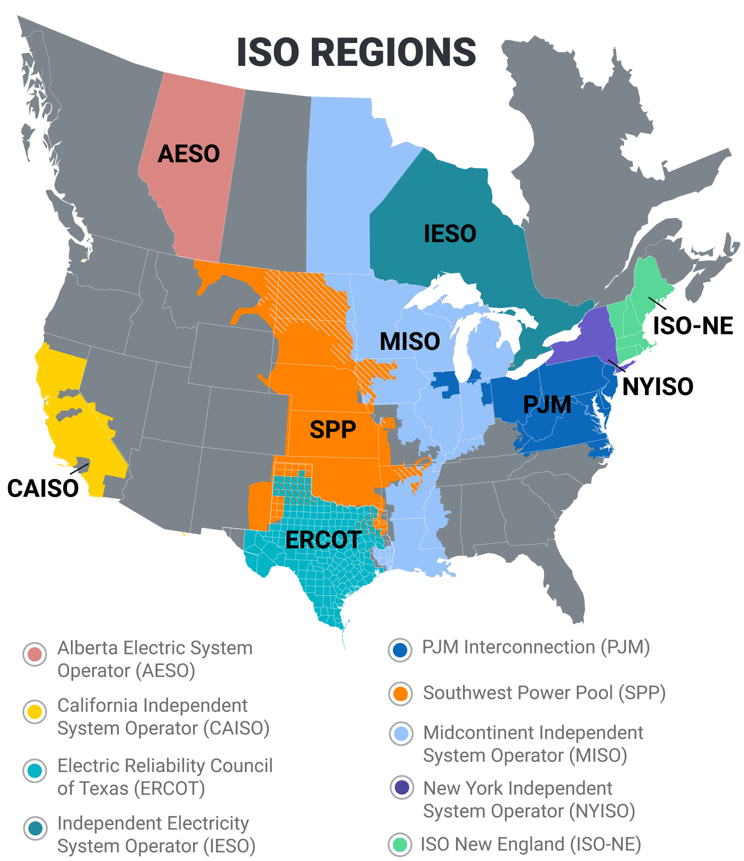
Table 1. Major Federal Transmission-Related Legislation

Legislation/Policy	Brief Description
Federal Water Power Act 1920 Federal Power Act 1935	Created the Federal Power Commission (FPC), now the Federal Energy Regulatory Commission (FERC), whose mandate is to achieve reasonable, nondiscriminatory, and just consumer rates. It licenses hydroelectric power plants and regulates the interstate activities of the electric power and natural gas industries. In 1935, the Act was renamed the Federal Power Act (FPA), and the FPC's jurisdiction was expanded to include all interstate electricity and wholesale power sales ("sales for resale").
Energy Policy Act 1992	Amends the Public Utility Holding Act of 1935 to allow for open access to the transmission systems of FERC-regulated utilities and enables states to decide whether to implement retail electricity competition.
Energy Policy Act 2005	The FPA was amended to extend the FERC's jurisdiction to electric service reliability, among other items.
Fixing America's Surface Transportation Act (FAST Act) 2015	Establishes the Permitting Council, an independent federal agency, to facilitate federal environmental review and permitting for covered infrastructure projects, including electricity transmission and renewable energy.

Infrastructure Investment and Jobs Act 2021	The Infrastructure Investment and Jobs Act (IIJA) allocates significant funding to increase nuclear and hydroelectric sources, improve the resilience of the grid, replace, enhance, or facilitate electrical transmission lines, and fund electric vehicle infrastructure and battery processing. For example, the Transmission Facilitation Program (TFP) and the Grid Resilience and Innovation Partnership (GRIP) support transmission development by providing financial incentives and funding for interregional transmission projects, grid upgrades, and innovations to enhance grid resilience and reliability.

FERC's role in transmission is fundamental and increasing. While it has jurisdiction over investor-owned utilities, FERC does not regulate consumer-owned utilities, such as rural cooperatives or municipal utilities. FERC Orders 888/889 outline the regulation of wholesale electricity markets, requiring transmission owners subject to its authority to provide open access to the transmission system for generation. The United States has two different market structures: centralized markets administered by RTOs/ISOs and bilateral markets, both of which are further described below. The RTOs/ISOs service areas are depicted in Figure 8, and the unlabeled regions are those with bilateral markets. FERC also determines interstate transmission rates. The ERCOT grid is not under FERC's jurisdiction because its grid operates almost entirely within the state of Texas and does not connect to other states' power grids. This means it does not engage in interstate electricity commerce, which is what FERC regulates under federal law.

Figure 8. U.S. RTO/ISO Map[18]



In Order 881, FERC promulgated non-wire alternatives, described further below, to increase the capacity of the existing transmission system and reduce the amount of new transmission needed. FERC Order 2023 addresses generation interconnection issues, specifically the backlog of generation requests in interconnection queues. FERC Orders 890 and 1000 require interregional transmission planning and cost allocation based on who benefits from the new transmission, which are discussed further below. FERC Order 1000 also eliminates the federal right of first refusal (ROFR), meaning transmission utilities no longer have the exclusive right to build, maintain, and own transmission lines within their service territory. FERC Orders 1920 and 1920-A require regional and interregional transmission planners to adopt long-term, forward-looking planning processes to address evolving grid needs. Table 2 summarizes these critical FERC orders.

Table 2. FERC Orders and Notice of Proposed Rulemaking Applicable to Transmission

FERC Order No.	Date	Description
888/889	1996	Establishes transmission open access, the functional unbundling of wholesale transmission and generation by utilities, and the posting of available transmission.
2000	2000	Provides for but does not require regional transmission organizations (RTOs).
890	2007	Directs transmission providers to develop a transmission planning process that satisfies nine principles laid out by the Commission.
1000	2011	Reforms the Commission's electric transmission planning and cost allocation requirements for public utility transmission providers.
881	2021	Requires transmission providers to implement and use ambient-adjusted ratings for transmission lines.
2023	2023	Directs all public utility transmission providers to revise their pro forma generator interconnection queue rules.
1920	2024	Adopts specific requirements how transmission providers must conduct long-term planning and cost-allocation.
1920-A	2024	Modifies FERC Order 1920 to enhance the role for states in the planning process.

Note: FERC order numbers do not indicate chronology, i.e., smaller numbers are not necessarily earlier.

As mentioned before, NERC is responsible for the reliability rules and assesses the ability of the North American BPS (generation and transmission) to function reliably.

There are many other federal and state policies affecting transmission planning. At the federal level, some important statutes are the Clean Water Act, the Endangered Species Act, the National Environmental Policy Act, and the National Historic Preservation Act. Moreover, states may have co-jurisdiction under some of these acts.

Surface and subsurface land ownership can be extremely complicated. Federal and state governments and Native American tribes own large amounts of land that new transmission facilities may need access to. Access to land can be complicated by the separation of surface and mineral rights, checkerboard land ownership, and federal and state land use management plans. Construction schedules may be limited due to wildlife migratory and habitat restrictions. Depending on the state, the siting authority may be vested with the public utility commission, a separate siting agency, or both.[19] States also have laws and regulations regarding certificates of public convenience and necessity, eminent domain and condemnation procedures, and landowner compensation that varies by state.

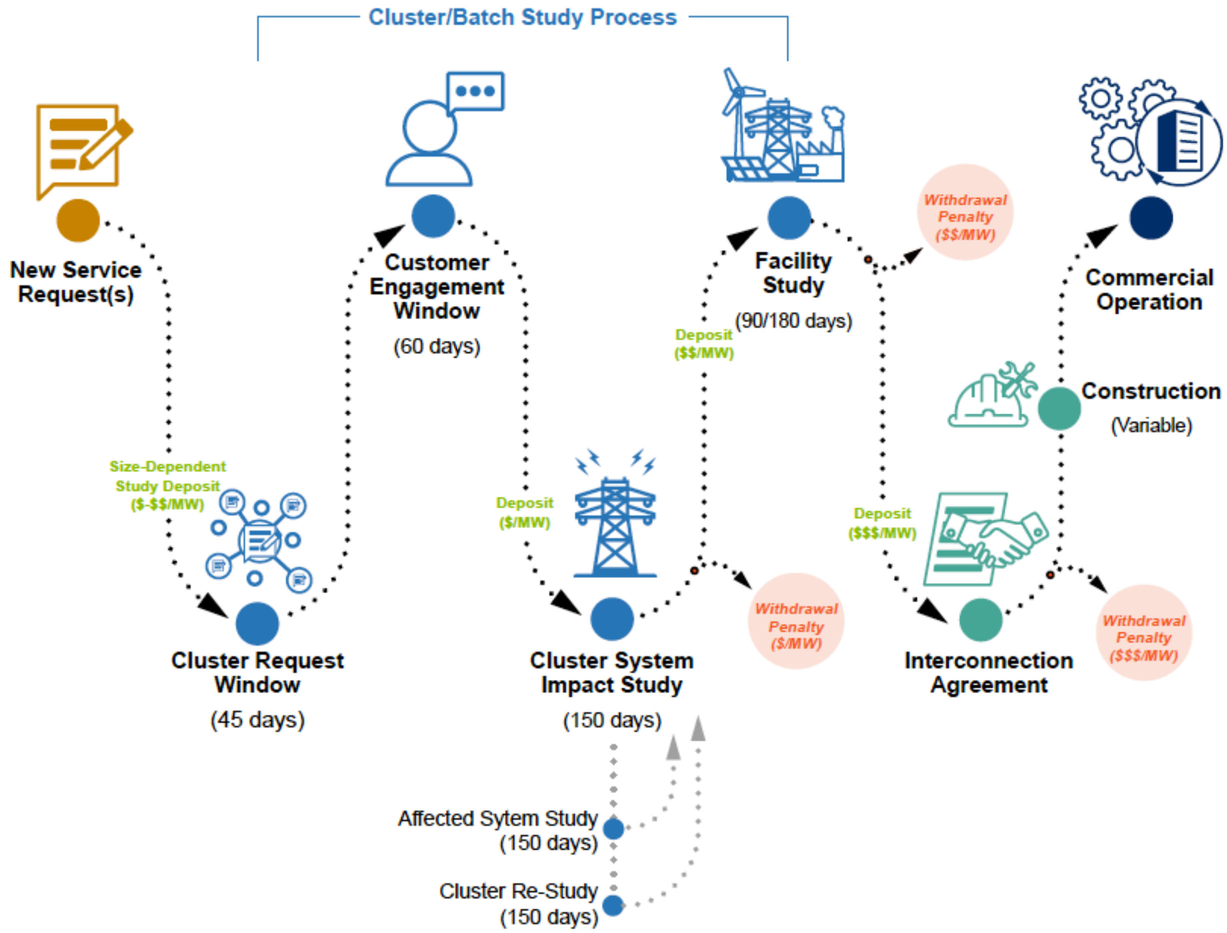
IV. Federal and State Transmission Planning

A. Federal and State Transmission Planning Processes

FERC has identified four types of transmission drivers: generation interconnections, reliability, economics, and public policy (such as states' efforts to decarbonize). During the generation development process, developers request a transmission interconnection study from the local utility or RTO. This study aims to determine the necessary facilities and the costs of interconnecting the proposed unit reliably to the grid. Given the loop flow characteristics of AC power systems, the impact may not be limited to the interconnecting utility. Additional transmission may be necessary beyond the facilities that directly interconnect the project. Moreover, generators may be able to request different levels of interconnection to enable their generation unit to deliver its power to high-price regions on the grid.

At any given time, multiple interconnection requests from generation developers to a utility or RTO exist. These requests form what is referred to as an interconnection queue. Not all proposed generation is built, so if a generation unit leaves the queue, that can affect the interconnection studies of other projects. Utilities and RTOs have detailed rules regarding the interconnection queues, including posting funds to pay for the interconnection study and requiring feasibility studies to show if a project is credible. Figure 9 illustrates the typical process.

Figure 9. Simplified Interconnection Study Process and Timeline[20]



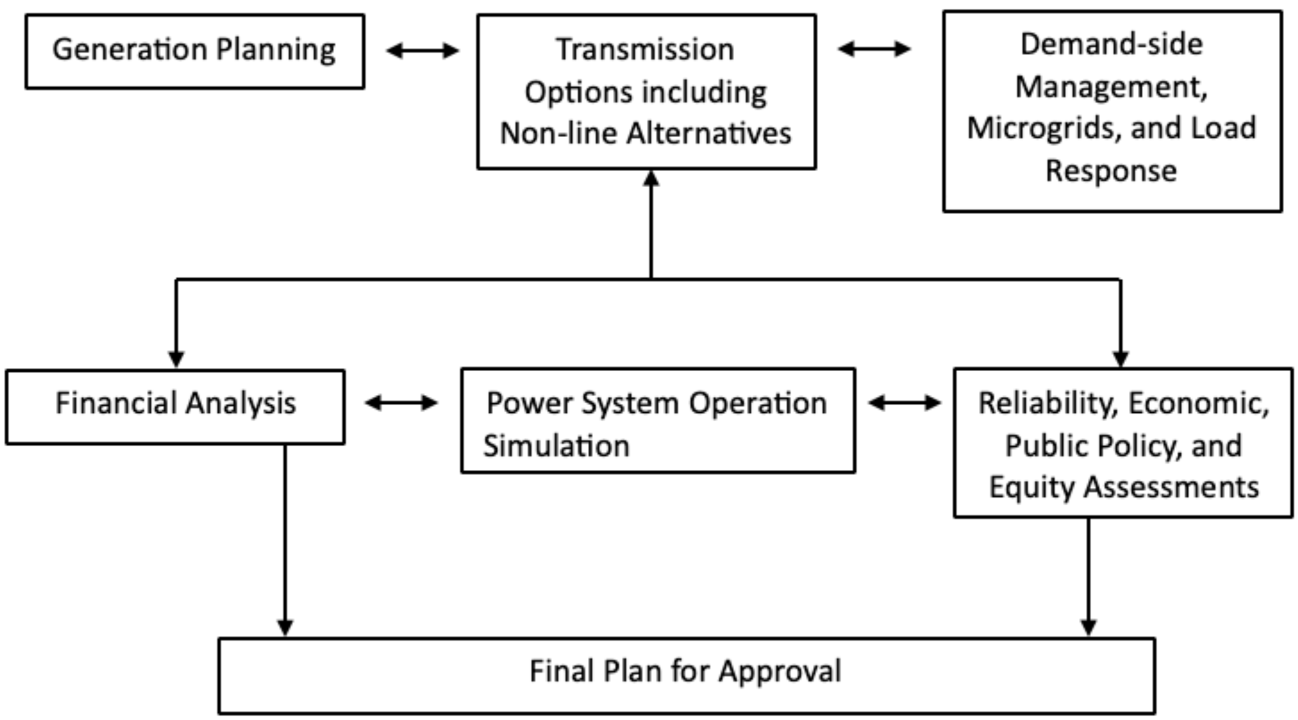
Currently, the U.S. interconnection queues are long. A recent study covering 85% of U.S. electricity consumers found over 10,000 active projects and 1,350 GW of generator capacity in the queue.[21] The same study found that between 2000-2016, only 21% of all proposed projects reached commercial operation and that the typical lag time between interconnection requests and commercial operations was about five years.

Considering load growth and shifts, generation retirements and interconnections, and aging transmission equipment, additional intra- and interregional transmission facilities are being planned to meet anticipated reliability needs. These are based on federal and NERC reliability requirements, economic criteria to reduce congestion and generation costs, and public policy objectives. Specific transmission planning goals include reducing congestion, balancing supply and demand over large regions, supporting renewable resources and carbon reduction goals, interconnecting new generation, improving resiliency (mainly due to severe weather events), and coping with increased electricity demand generally. Community engagement is now also becoming part of transmission planning processes. Additionally, ensuring that interconnection queue discussions and transmission planning are seamlessly integrated is crucial. This alignment helps to address interdependencies between new generation projects and transmission infrastructure development, thus supporting overall grid reliability, economic efficiency, and policy objectives.

There are multiple ways in which new transmission facilities are initiated. Possible initiating requests for new transmission can come from generation developers, local utilities, integrated resource plans, RTOs/ISOs, and merchant transmission developers. Merchant transmission refers to an entity without a utility service territory that develops transmission facilities funded by market participants, either directly or through the sale of transmission congestion rights.

The generic transmission process involves conducting a needs assessment, proposing candidate transmission solutions and, perhaps, non-transmission alternatives, a cost-benefit analysis, a cost allocation study, and finally, obtaining regulatory approvals. Figure 10 diagrams a typical transmission planning process.

Figure 10. Generic Transmission Planning Process[22]



Key Fact #3: Transmission planning occurs at the national, regional, and local levels, and the objectives of transmission planning may include new equity considerations, clean energy development and decarbonization, and resiliency.

Policy Implication #4: Navigating federal and state transmission objectives and requirements necessitates extensive involvement by states to achieve their electricity and energy policy objectives while maintaining a reliable and efficient electric grid.

B. Transmission Costs

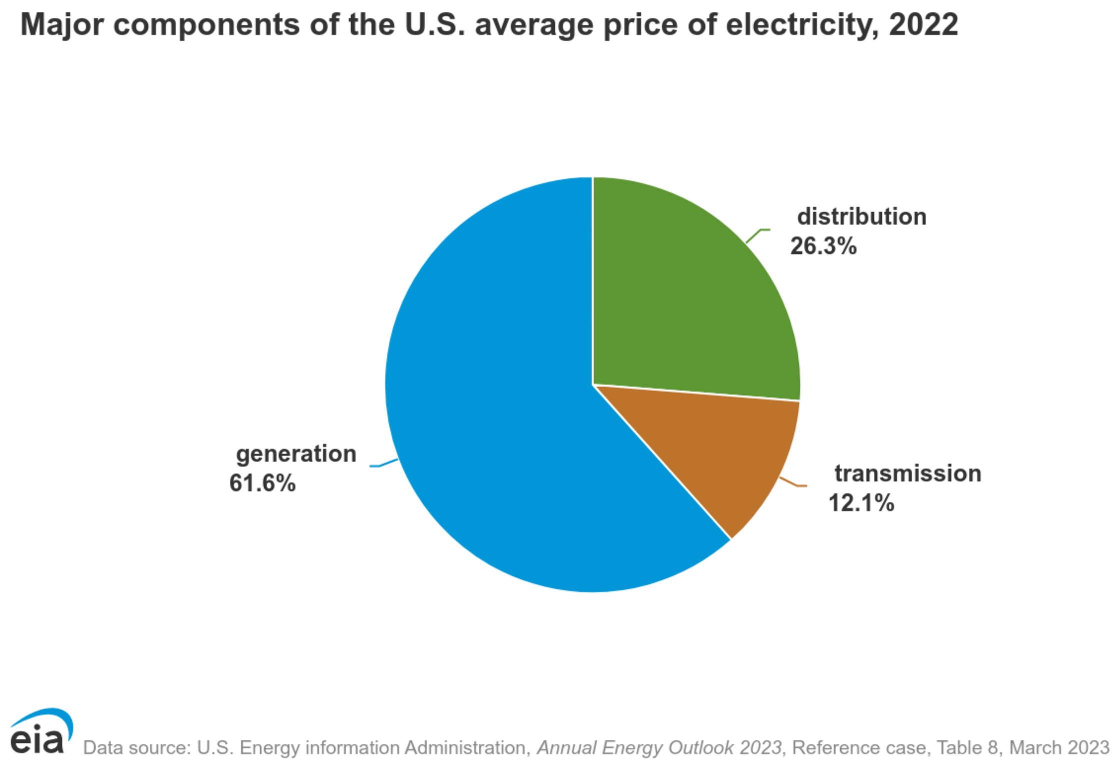
Cost estimates for transmission vary considerably. Generally, they are reported in cost-per-mile. However, the costs depend on factors such as voltage and transfer capacity, whether the lines are AC or DC, whether they are overhead or underground, and the terrain (e.g., mountains, lakes, rivers, offshore). Additionally, the use of existing rights-of-way such as rail and highways can also influence costs. Except for merchant transmission, the costs of transmission are recovered via cost-of-service ratemaking. A transmission line's investment amount, cost of capital, maintenance, and operating costs are determined and translated into a transmission rate that recovers those costs over the lifetime of the facility.

Transmission cost allocation is a complicated and controversial topic. It is important to note that FERC regulates transmission that crosses state lines and has jurisdiction over transmission rates in most parts of the country, except for Hawaii, Alaska, and Texas.[23] FERC's cost allocation policy is that transmission costs are to be allocated roughly commensurate with their estimated benefits. Cost allocation of transmission projects is based upon the following seven economic and reliability benefits of the project: 1. Reduced transmission costs; 2. Improved resource adequacy; 3. Reduced generation fuel and variable costs; 4. Reduced transmission losses and associated costs; 5. Reduced transmission congestion costs; 6. Mitigation of costs associated with extreme weather and unexpected system conditions; and 7. Reduced generation capacity cost from reduced peak energy losses. FERC Order 1920 does not change existing regional cost allocation methods for other transmission facilities. FERC Order 1920 does allow relevant state entities and transmission interconnection customers the option to voluntarily fund the cost or a portion of the cost of the proposed transmission facility. Transmission providers must provide timely notice of voluntary funding opportunities, the timeline, and other relevant information.[24]

Once the new transmission is built, its costs are incorporated into the existing regulated transmission rates. 'Pancaked' rates occur when electricity crosses more than one utility system, and each system charges its full rate to provide transmission service. Pancaking discourages transmission through multiple systems, limiting the economic benefits of long-distance transactions. 'Postage stamp' pricing allows for transmission within a region at the same price regardless of the distance between the seller of electricity and the buyer. In contrast, 'license plate' pricing means that different transmission rates are paid based on the delivery location, but consumers can purchase from anywhere within that region.

The major components of retail electricity bills are generation, transmission, distribution, public policy charges, and taxes. The amounts and percentages vary by region and utility, but transmission, on average, comprises about 10%-15% of a typical customer's electricity bill.[25] Transmission charges reflect both the local utility and regional transmission costs. Figure 7 provides the average breakdown of electricity costs.

Figure 7. Generation, Transmission, and Distribution Costs as a Percentage of a Typical Customer's Bill[26]



Key Fact #4: The financial costs of transmission are a relatively small, though growing, part of consumers' total electricity bill. These costs are based upon the amount of transmission investment, cost of capital, maintenance, and operational cost estimates.

Policy Implication #4: The financial costs of transmission are important, but they are only one component of transmission planning and siting. Equity, environmental impacts, reliability implications, generation, and congestion costs are critical considerations and, in many cases, are more challenging to assess and quantify than the financial costs.

C. Offshore Wind Transmission Planning Issues[27] [28]

While offshore transmission lines can be used to provide power to offshore oil and gas platforms, or to interconnect different regions or countries, the main focus of offshore transmission in the United States is for offshore wind. Many Northeastern states and California have made substantial commitments to develop offshore wind, and it is also being evaluated in Louisiana, Oregon, and Washington. In the Northeast, this offshore wind development will require an extensive offshore DC transmission network and enhancements of the existing AC land-based transmission system. Unlike onshore transmission development, offshore transmission infrastructure is often unique because it typically occurs in areas without existing energy infrastructure. It does not supply or connect consumers to

distribution grids directly. It is also constructed in challenging environments, requiring specific techniques, practices, and equipment for installation and maintenance. It often crosses multiple offshore jurisdictions, offshore regulatory zones, exclusive economic zones, and/or control area borders, requiring special/innovative regulation agreements.
In the early phases of development, offshore transmission links were initially point-to-point, optimized for their specific purpose, and with no considerations for future expansion or connection with other offshore transmission infrastructure. However, as the need for offshore transmission capacity increases, the United States is beginning to follow Europe's example of pursuing multi-purpose and more complex grid topologies. These grid topologies have several benefits over point-to-point links, including link and onshore substation outage mitigation (higher availability), reduced curtailments due to onshore grid constraints or congestion, relief for congested onshore grids, ancillary services, improved reliability and resiliency of supply to onshore grids, increased interzone and interregional capacity value, and fewer and larger circuits with reduced impacts on the environment and local communities, but at potentially a higher cost.[29] Due to the long distances and high capacities of offshore energy resources, high voltage direct current (HVDC) technology is also becoming widely used in offshore transmission systems. HVDC technology is developing rapidly, enabling new application areas such as multi-terminal and multi-purpose offshore grids, all of which raise new challenges.

DOE has been actively studying the transmission needed to support offshore wind energy development, both on the East Coast (Atlantic Offshore Wind Transmission Study) as well as the West Coast (West Coast Offshore Wind Transmission Study).

In 2024, the states in the Northeast entered into a Memorandum of Understanding to collaborate on the planning and development of robust interregional transmission planning, forming the Northeast States Collaborative on Interregional Transmission. The Northeast States Collaborative includes representatives from the State Energy Offices and state public utility commissions from Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont. The Northeast States Collaborative works on identifying key transmission priorities and developing practical solutions to building out the onshore and offshore transmission grid.[30]

D. Advanced and Emerging Transmission Technologies, Non-wire Alternatives, and Market Adoption Strategies

In addition to planning new physical transmission lines, transmission enhancements of existing lines can also help with grid expansion. There are multiple technologies and strategies that enhance the transmission system. Sometimes, they are referred to as non-wire options, non-transmission alternatives (NTAs), or advanced transmission technologies (ATTs). These options can help meet the demands of the changing electric power system alongside traditional transmission investments in high-voltage power lines, transformers, and associated equipment.

For example, installation of high-performance conductors (HPCs) on existing transmission lines can double the line capacity at an estimated half of the cost of building new transmission lines. Through implementation of this technology, energy losses can be reduced by between 25-40%, and the resilience and reliability can be enhanced due to increased thermal limits and reduced sag. Due to these findings, HPCs are being widely evaluated as cost-effective options to expand transmission capacity.[31]

Other non-wire options include grid-enhancing technologies (GETs), a collection of technologies that increase the flow of electricity on the grid. GETs include sensors, power flow control devices, and analytical tools. They can be cost-effective and improve the integration of new generation, but their impacts vary with their location.[32]They can usually be implemented more quickly than traditional alternatives. Specific GETs include dynamic line rating (DLR), and power flow controllers (PFCs).

DLR provides hardware and software that update the thermal limits of existing transmission lines based on real-time and near real-time conditions. This often enables additional power flow, in contrast to static ratings based on the most limiting weather conditions. Dynamic transformer rating (DTR) is the analog for transformers, the equipment that raises and lowers grid voltages to reduce electrical losses and deliver power at safe voltages. PFCs include hardware and software that redirect power over underutilized transmission lines to relieve transmission congestion, increase flows, and decrease costs. The U.S. electricity sector has been slow to adopt GETs due to technology challenges such as additional complexity and cybersecurity, and insufficient financial incentives to implement new, unproven technologies.[33]

Energy efficiency, demand response, price-responsive load, energy storage, microgrids, and virtual power plants (VPPs) are additional technologies (some of these are defined by some as GETs) that can reduce the need for traditional transmission investment while improving the system's performance. Energy efficiency reduces electricity demand and, therefore, the overall need for transmission. Demand response and price-responsive load reduce demand during crucial times when the transmission system is fully loaded. Increased electrification due to data centers and onshoring of manufacturing, electric vehicles (EVs), and electric heat will stress transmission more. Hence, cost-effective technologies and policies that shift electricity demand to low or lower demand periods are desirable.

Another strategy to reduce the cost of new transmission facilities is the colocation of transmission with other infrastructure, such as highways, railroads, broadband, and other existing rights-of-way infrastructure corridors. The NextGen Highways coalition is an example of such an effort.[34] NASEO has worked with NextGen Highways to produce a guide on *Reimagining Highway Rights-of-Way as Transmission Corridors: Opportunities and Considerations for State Energy Offices*, highlighting the benefits of transmission colocation in highway rights-of-way and identifying opportunities and considerations for them to support this avenue. Additionally, NASEO has also produced several resources that focus on advanced grid solutions, which are posted on the NASEO website here.

> *Key Fact #5: Multiple technologies and strategies are available to enhance the reliability, efficiency, and capacity of the U.S. transmission system. They both substitute for and complement additional transmission lines on new and existing routes and increase their voltage.*

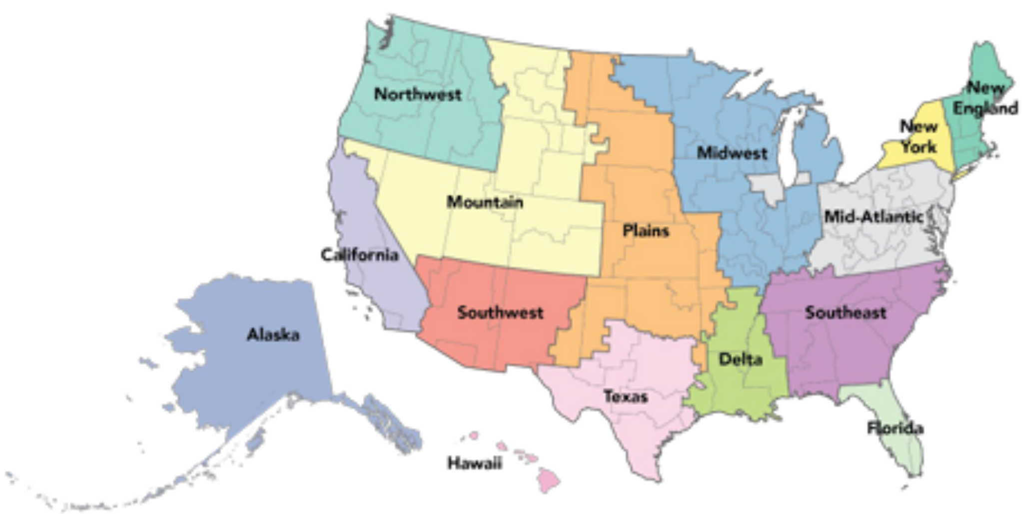
Policy Implication #5: Incorporating alternatives to traditional transmission facilities is challenging, requires sustained systematic planning and coordination, new financial incentives, and is necessary to cost-effectively plan the grid.

V. Regional Transmission Issues and Their Implications for States

A. Continental United States Electricity Markets and Transmission

As previously discussed, the current and planned generation mix varies substantially by region, impacting individual regions' transmission needs. This section provides a high-level summary of some of the U.S. regional transmission needs. It is based on a recent review of over 50 studies by DOE and is supplemented with additional references.[35] [36] Recent extreme cold and hot weather events have highlighted the need for improved reliability and resiliency in all regions.[37] In addition, multiple studies have found the need to significantly increase national interregional transmission capacity, including with Canada, if significant amounts of renewable resources are developed. Figure 11 identifies the regional breakdown used in the subsequent discussion along with the RTO/ISO map provided in Figure 8 above.

Figure 11. Geographic Regions Used in DOE 2023 National Transmission Needs Study[38]



Wholesale electricity markets and transmission issues are tightly coupled. The United States has two major types of wholesale electricity markets. One is the RTO/ISO-type market, which includes New England (ISO-NE), New York (NYISO), the Mid-Atlantic, (PJM) the Midwest (MISO, PJM), the Delta (MISO, SPP), the Plains (MISO, SPP), Texas (ERCOT), and California (CAISO). RTO/ISO markets have electric energy markets whose prices vary by hour and location. They also have other markets for transmission rights, ancillary services, and, except for ERCOT, capacity markets. Efforts are ongoing to extend the RTO/ISO-type market beyond California in the West and consider its development in the Southeast.

The second major type of wholesale electricity market is in the Southern, Midwest, Mountain, and portions of the Western regions of the United States. These markets are referred to as 'bilateral' markets. Bilateral means that buyers and sellers of electricity conduct transactions in a decentralized fashion. No single entity, like an RTO/ISO, administers wholesale electricity markets. Instead, buyers and sellers make bilateral arrangements and purchase transmission rights from transmission owners. Utilities are typically vertically integrated, i.e., they own generation, transmission, and distribution.[39] Regional utilities are developing the Southeast Energy Exchange Market (SEEM) to formalize and extend the bilateral contracting framework.

> *Key Fact #6: The United States has two different wholesale market structures, and there are important similarities and differences within each structure that affect transmission planning.*
>
> *Policy Implication #6: To be effective, transmission policies and planning need to account for wholesale market structures. This is complicated by the variations in wholesale market structures across the country.*

B. Northeast and Mid-Atlantic Regions

The Northeast and Mid-Atlantic regions have three interconnected RTO/ISO-type markets: the Independent System Operator New England (ISO-NE), the New York Independent System Operator (NYISO), and Pennsylvania, New Jersey, Maryland (PJM); although PJM's footprint now extends well beyond these three states. Though some essential details differ among these RTOs/ISOs, they have similar market designs. There are real-time and day-ahead energy markets with locational-based marginal prices (LBMPs, sometimes referred to as locational marginal prices [LMPs]). There are ancillary service markets for operating reserves and other necessary services to maintain reliability. There is also a market for capacity to ensure sufficient resources, referred to as resource adequacy, to meet demand under various conditions. All of these RTOs/ISOs administer their regions' Open Access Transmission Tariff (OATT), conduct transmission planning, and evaluate market performance.

A transmission issue faced by all three RTOs/ISOs in the Northeast is developing a transmission system for offshore wind. Coastline states have made substantial commitments to develop offshore wind, which requires either radial DC lines or a DC network to connect the wind farms to shore. Moreover, this development affects onshore transmission flows and may require additional AC transmission facilities.

New England has a constrained natural gas system that poses a reliability risk during winter months. Its transmission needs include increasing the transfer capacity with New York and Canada, the latter for the bi-directional flow of generation between Canada and the United States. In New York State, there is extensive transmission congestion between upstate New York, New York City, and Long Island, and the state is developing transmission to help reduce this congestion. Furthermore, New York and its neighbors need additional regional transmission transfer capacity. Some of this need will be addressed with the Champlain Hudson Power Express (CHPE) transmission line. CHPE is a high-voltage direct current line designed to deliver clean hydropower from Canada to New York City. In the Mid-Atlantic, there is intra-PJM congestion in the eastern portion of the region near the Maryland, Delaware, Pennsylvania, and New Jersey borders. Within the PJM footprint, states in the Midwest have substantial onshore wind resources whose power flows from west to east. As Midwestern wind is further developed, this may require additional transmission within PJM and between PJM and neighboring regions.

C. Southern Region

Anticipated transmission needs in the Southeast include additional intra- and interregional transmission to meet the projected load growth and additional generation due to the growth in data centers, manufacturing, and population. Due to its intense hurricanes and subsequent flooding, Florida has taken steps to substantially improve the resilience of its electric system. However, additional transmission within Florida may benefit the state by increasing transfer capability with the rest of the Southeast.

D. Midwest, Delta, Mountain, and Plains Regions

For the most part, the Midwest, Delta, and Plains regions' two wholesale electricity markets are the Midwest Independent System Operator (MISO) and the Southwest Power Pool (SPP). MISO has a similar market structure to the RTOs/ISOs in the Northeast. It has implemented a multi-value project (MVPs) transmission planning process and a Long-Range Transmission Planning (LRTP) initiative, Both the MVP and LRTP are considered best practices from a transmission planning perspective.[40] SPP is an RTO that operates and day-ahead energy markets, an operating reserve market, and a market for transmission congestion rights. SPP has also established a Consolidated Planning Process (CPP) designed to streamline and enhance the planning and cost-sharing mechanisms for transmission projects.[41] SPP has also expanded its footprint into the West.

The Plains' transmission needs include increased capacity within the region and with its neighbors in the event of cold weather, high electricity prices, and significant differences in wholesale prices within the region. It also requires additional transmission to meet increasing load and the objective of a clean energy future.

Transmission planning conducted by MISO and SPP document that additional transmission may be needed in the Midwest and Delta regions to reduce congestion, improve access to low-cost generation, and meet projected generation and demand growth. The DOE 2023 National Transmission Needs Study highlights the need for increased transfer capacity between the Midwest and the Delta, Plains, and Southeast regions.

The Mountain region has a traditional bilateral wholesale electricity market where public utilities are responsible for system operations and providing power to retail customers. Extreme heat and wildfires are a reliability concern. Reliability transmission upgrades may be necessary along the eastern edge of the Mountain region as transmission is expanded along the West Coast. An increase in transfer capacity between the Mountain region, its Western Interconnection neighbors, and the Plains is also needed.

E. Electricity Reliability Council of Texas (ERCOT)

ERCOT includes 90% of the electricity load in Texas.[42] It is an ISO that operates an organized wholesale electricity market but is not under FERC jurisdiction. It operates real-time, day-ahead, and ancillary service markets like other RTOs/ISOs, but it does not have a capacity market. Instead, it relies on scarcity pricing during high demand to signal the need for additional generation. As in other parts of the country, recent extreme cold and hot weather events have highlighted the need for improved reliability and resiliency. ERCOT's 2022 Report on Existing and Potential Electric System Constraints and Needs highlights the need for significant transmission development within Texas to meet load growth. To contribute greater wind energy generation to the grid, the Texas state legislature created Competitive Renewable Energy Zones (CREZs) in 2005. Through the legislation, the Texas Public Utility Commission, in consultation with ERCOT, was tasked with developing these zones based on the potential for large-scale wind development. Additionally, the Commission and ERCOT maintained the responsibility of developing transmission plans focused on delivering additional power from the zones to the grid.[43]

F. Western Regions

The West is a mixture of RTO/ISO and bilateral wholesale electricity markets. The California Independent System Operator (CAISO) has a similar market structure to the RTOs/ISOs in the Northeast and Mid-Atlantic regions. The rest of the West has a bilateral market. CAISO also operates an energy imbalance market (EIM) that includes other entities in the West.

The Northwest includes the Bonneville Power Administration (BPA) and the Western Area Power Administration (WAPA), which operate and plan transmission. In 2021, extreme heat and wildfires raised reliability and resource adequacy concerns and created high dependence on variable energy resources. Unscheduled transmission flows (i.e., loop flows) between California and the Northwest are a concern.

California's transmission needs include improved system reliability and resiliency due to extreme heat and wildfires, its focus on solar and imports, its constrained natural gas system, and expected generation retirements. Additional transmission may be needed to reduce unscheduled flows and congestion costs between California and the Northwest and reduce California's electricity prices. Additional transmission may also be needed with neighboring regions to meet projected load and generation growth.

It should be noted that in the West, the Committee on Regional Electric Power Cooperation (CREPC), a joint committee created by the Western Interstate Energy Board and the Western Conference of Public Service Commissioners, has been in place since 1982. CREPC is comprised of a State Energy Office representative and a regulatory utility commissioner from each of the Western states and Canadian provinces and focuses on electric power system policy issues that require regional cooperation in the region. CREPC has established a Transmission Collaborative, an informal working group focused on regional transmission issues and serves as a forum for collaboration on transmission coordination and development in the West. Additionally, the [Western Transmission Expansion Coalition](#) (WestTEC) is working on a comprehensive transmission study to support the future energy grid. WestTEC involves a diverse range of industry sectors, states, and tribes in inclusive and transparent planning processes to address the region's future transmission needs.

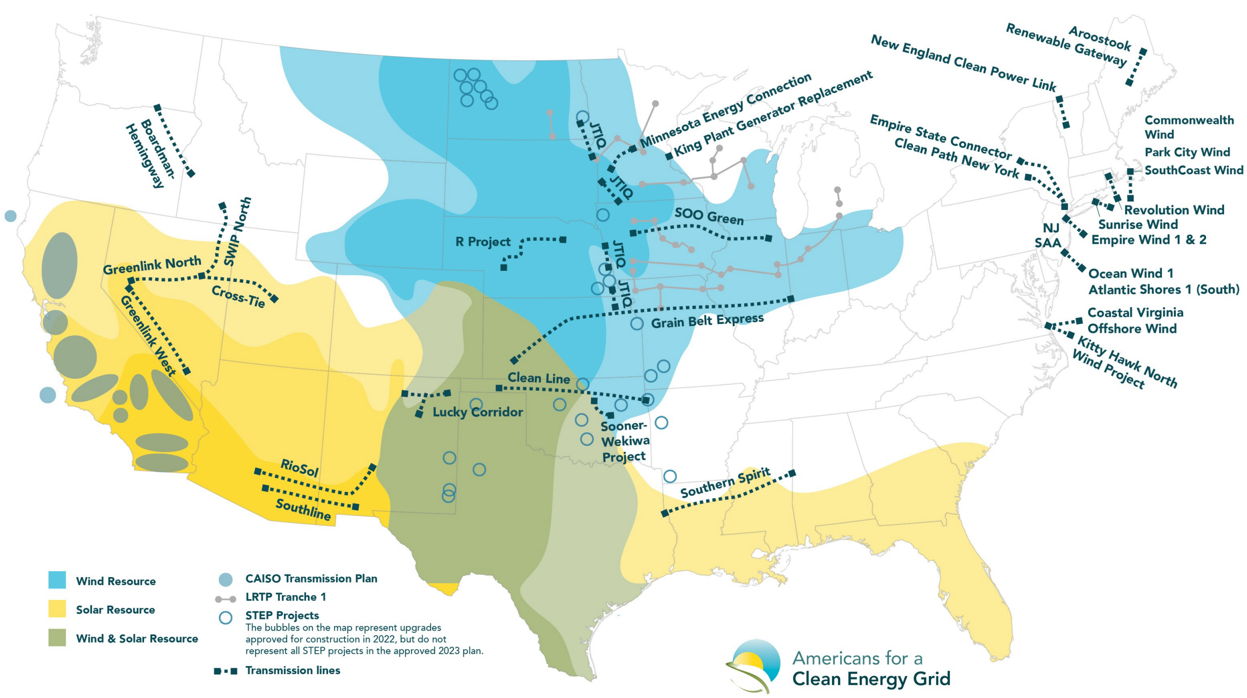
In the Southwest, extreme heat and wildfires are reliability concerns. Additional transmission may be needed along the eastern edge of the Southwest as transmission is expanded along the West Coast.

The situation in the West remains quite dynamic with multiple discussions on how a more formalized market could be formed or how utilities could join SPP or CAISO. In 2024, FERC published an explainer highlighting the current discussion and development so far.

G. Proposed Major Transmission Projects and Regional Planning Entities

Numerous transmission facilities are in the planning pipeline. Figure 12 provides a high-level view of 36 major U.S. proposals. It gives some sense of the types of large-scale and interregional or offshore wind transmission projects that could begin construction in the near term.[44] These transmission facilities are only mentioned to illustrate the types of continental United States projects pursued and do not constitute an endorsement. Another source highlighting the status of transmission throughout the country can be found in the 2024 State of Regional Transmission Planning, conducted by the Americans for Clean Energy Grid.

Figure 12. Thirty-six Proposed Major U.S. Transmission Projects[45]



Major transmission lines require interregional planning. Table 3 summarizes the regional entities involved in U.S. transmission planning.

Table 3. Regional Entities Involved in U.S. Transmission Planning[46]

Region	RTO/ISO	Transmission Planning Entity	Reliability Assessment Area
California	CAISO	CAISO	WECC: CA/MX
Northwest		Northern Grid	WECC: NWPP & RMRG
Mountain		Northern Grid & WestConnect	WECC: NWPP & RMRG
Southwest		WestConnect	WECC: SRSG
Texas	ERCOT	ERCOT	Texas RE: ERCOT
Plains	SPP	SPP	SPP
Midwest	MISO	MISO	MISO
Delta	MISO	MISO	MISO
Southeast		SERTP & SCRTP	SERC: Central, East & Southeast
Florida		FRCC	SERC: Florida Peninsula
Mid-Atlantic	PJM	PJM	PJM
New York	NYISO	NYISO	NPCC: New York
New England	ISO-NE	ISO-NE	NPCC: New England

VI. Conclusion

Successful transmission planning and deployment are critical for states to achieve their energy policy objectives regarding reliability, economic development, environmental enhancements, and equity. Transmission provides a vital link between generation and load. Due to the complexity of how electricity flows on a predominately AC grid, close planning and coordination between the federal government, states, Canada, RTO/ITOs, utilities, and generation developers is necessary.

Transmission planning is a complex, multi-jurisdictional, regional, state, and local activity requiring the integration of technical solutions. It also entails modeling and planning challenges, economic considerations such as cost allocation, stakeholder involvement, and broader public policy considerations such as affordability and environmental impacts. Multiple modeling and analyses are necessary to assess the implications of new and retiring generation and new transmission facilities. Beyond ascertaining the technical and economic issues, communication among interested parties in a timely and effective manner is required.

Many State Energy Offices can play pivotal roles in transmission planning and implementation. State Energy Offices that are knowledgeable and up to speed on current and emerging transmission issues can enhance their region's transmission planning efforts by integrating their states' energy policies, utility regulatory considerations, broader public policy objectives with stakeholder involvement, public outreach, and education. Federal and state regulatory agencies have stipulated mandates that may have gaps that State Energy Offices can help fill. These include public policy priorities, public acceptance, and communication.

For more detailed information on opportunities for State Energy Office engagement in transmission policy and planning, please refer to other NASEO publications on the NASEO website. These resources provide comprehensive insights and examples that can help State Energy Offices play a pivotal and active role in transmission planning and deployment.

Additional Resources

Primers on the electric power grid in general and transmission in particular:

- Federal Energy Regulatory Commission (FERC), Energy Primer: A Handbook for Energy Market Basics, April 2020

- National Regulatory Research Institute (NRRI), Transmission Investment Commissioner Primer, July 2006

- National Conference of State Legislatures, Electricity Markets: A Primer for State Legislators, January 2022

- National Council on Electricity Policy, Electricity Transmission: A Primer, June 2004

- U.S. Department of Energy, United States Electricity Industry Primer, July 2015

Resources that discuss equity:

- Argonne National Laboratory, Energy Equity

- National Association of Regulatory Utility Commissioners (NARUC), State Energy Justice Roundtable Series: Energy Justice Metrics, February 2023

- National Renewable Energy Laboratory (NREL), Energy Justice

- Pacific Northwest National Laboratory (PNNL), DOE National Laboratories Identify Equity and Justice Opportunities

- Sandia National Laboratories, Energy Equity & Environmental Justice

Studies regarding U.S. and regional transmission needs:

- Americans for a Clean Energy Grid, Transmission Planning and Development Regional Report Card, June 2023

- Berkeley Lab, Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection As of the End of 2022, April 2023

- Federal Energy Regulatory Commission, Joint Federal-State Task Force on Electricity Transmission

- Federal Energy Regulatory Commission Staff Report on Barriers and Opportunities for High Voltage Transmission, June 2020

- U.S. Department of Energy, Annual US Transmission Data Review, March 2018

- U.S. Department of Energy, National Transmission Needs Study, October 2023

Alternatives to transmission lines:

- National Association of Utility Commissioners and National Association of State Energy Offices, Clean Energy Microgrids: Consideration for State Energy Offices and Public Utility Commissions to Increase Resilience, Reduce Emissions, and Improve Affordability, May 2023.

- U.S. Department of Energy, Grid-Enhancing Technologies: A Case Study on Ratepayer Impact, February 2022

State transmission siting issues:

- National Council on Electricity Policy, Mini Guide on Transmission Siting: State Agency Decision Making, December 2021

- National Governors Association, How Governor Leadership Can Advance Projects

- U.S. Department of Energy, Transmission Siting and Permitting Efforts

Regional state organizations involved in transmission and wholesale electricity markets

- Midwestern Governors Association

- New England States Committee on Electricity (NESCOE)

- Organization of MISO States (OMS)

- Organization of PJM States, Inc. (OPSI)

- Western Interstate Energy Board (WIEB)

Acronyms

AARs: Ambient adjusted ratings

AC: Alternating current

BPS: Bulk power system

CAISO: California Independent System Operator

CREZ: Competitive Renewable Energy Zones

DC: Direct current

DLR: Dynamic line rating

DTR: Dynamic transformer rating

DOE: U.S. Department of Energy

EIA: U.S. Environmental Information Agency

EPA: U.S. Environmental Protection Agency

EVs: Electric vehicles

FACTS: Flexible alternating current transmission systems

FERC: Federal Energy Regulatory Commission

FPA: Federal Power Act

FPC: Federal Power Commission

GETs: Grid-enhancing technologies

GW: Gigawatt

HVAC: High voltage alternating current

HVDC: High voltage direct current

ISO: Independent system operator

LMBP: Locational based marginal price

LMI: Low and moderate income

LMP: Locational marginal price

MISO: Midcontinent Independent System Operator

MW: Megawatt-hour

MWh: Megawatt-hour

NARUC: National Association of Regulatory Utility Commissioners

NASEO: National Association of State Energy Officials

NERC: North American Electric Reliability Corporation

NOPR: Notice of Proposed Rulemaking

NTA: Non-transmission alternatives

OATT: Open Access Transmission Tariff

PFC: Power flow controllers

PPTN: Public Policy Transmission Needs

PSC: Public Service Commission

PUC: Public Utility Commission

PUCT: Public Utility Commission of Texas

PV: Photovoltaic

REZ: Renewable energy zones

ROFR: Right of first refusal

RTO: Regional transmission organization

SPP: Southwest Power Pool

Endnotes

[1] Transmission facilities are structures associated with the transmission of electricity, such as transmission power lines, transmission towers, substations, and transformers.
[2] U.S. Department of Energy, Grid-Enhancing Technologies: A Case Study on Ratepayer Impact, February 2022, p. 1.
[3] National Council on Electricity Policy, Electricity Transmission: A Primer, June 2004.
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[28] The White House, FACT SHEET: Biden-Harris Administration Announces Actions to Expand Offshore Wind Nationally and Harness More Reliable, Affordable Clean Energy, February 23, 2023.
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[30] Johns Hopkins University, Northeast States Collaborative on Interregional Transmission, accessed February 24, 2025.

[31] U.S. Department of Energy, Innovative Grid Deployment: Pathways to Commercial Liftoff, Interim Webinar Update, December 12, 2023.
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[34] NextGen Highways, NextGen Highways, accessed February 24, 2025.
[35] U.S. Department of Energy, National Transmission Needs Study, Draft for Public Comment, February 2023.
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