PRIMER

ELECTRIC TRANSMISSION PLANNING

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CEBI
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AUTHORS & ACKNOWLEDGEMENTS

Author

Brian Morgan,
Clean Energy Buyers Association

KEY CONTRIBUTORS

Heidi Ratz
Clean Energy Buyers Association

Jennie Chen
ReGrid

Adrienne Mouton-Henderson,
Clean Energy Buyers Association

ABOUT THE CLEAN ENERGY BUYERS INSTITUTE

The Clean Energy Buyers Institute (CEBI) solves the toughest market and policy barriers to achieve a carbon-free energy system. CEBI's aspiration is to achieve a 90% carbon-free U.S. electricity system by 2030 and a global community of customers driving clean energy.

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OVERVIEW

OVERVIEW: Well-planned and timely transmission development is critical for connecting new clean energy resources to the grid and optimizing the operation of the wholesale electricity system. Energy customers with clean energy goals are increasingly prioritizing improved transmission planning to speed decarbonization of the grid, but they need educational resources to engage more fully on transmission topics.

The Electric Transmission Planning Primer is intended to educate energy customers on the basics of transmission planning by exploring infrastructure components, jurisdictional authorities, key stakeholders, and current planning processes. The Primer explores the role of transmission in efforts to decarbonize the grid, in achieving energy customers' clean energy goals, and the challenges and reform opportunities under existing transmission policies.

THE PURPOSE Energy customers can utilize the Electric Transmission Planning Primer as a reference document when navigating transmission planning processes, or as a starting point for understanding what future transmission reforms are needed to support decarbonization of the grid.

INTENDED AUDIENCE: This Primer is targeted towards energy customers with a basic knowledge of the electricity system and an interest in transmission planning..

TABLE OF CONTENTS

CUSTOMER INTEREST IN TRANSMISSION PLANNING

Transmission is the network of high-capacity electric wires and support equipment that moves large amounts of electricity from points of supply to points of demand. As one of the three major components of the electric system—the others are generation and distribution as shown in **Figure 1**—almost 700,000 circuit-miles[i] of transmission link generators to the local delivery networks that provide electricity to customers in the U.S.[1]

RELATIONSHIP BETWEEN TRANSMISSION AND CLEAN ENERGY

Transmission enables the efficient transfer of low-cost renewable energy to distant areas with high demand for carbon-free power. Historically, fossil fueled generation could be constructed relatively close to major load centers if adequate means to transport fuel existed. In contrast, renewable energy generation developers seek to build in locations with substantial amounts of wind and sun. These areas frequently lack sufficient existing transmission infrastructure to cover large-scale renewable deployment, cover wide geographic regions, and are not located near major demand centers. For example, 15 states between the Rocky Mountains and the Mississippi River account for 88% of the nation's potential wind capacity and 56% of potential solar capacity. However, those states are only projected to account for 30% of national electricity demand by 2050.[2]

Transmission expansion can further increase the reliability of the electric grid. Greater interconnectedness can mitigate the variability of renewable sources—periods when output halts because the sun stops shining or the wind stops blowing—by linking multiple generators together across a diverse geographic region to ensure an adequate power supply regardless of the weather conditions at a specific site.

Building out transmission also facilitates federal and state policy goals to decarbonize the electric system, which is the second largest source of greenhouse gas emissions in the U.S. Research demonstrates the nation will need to increase transmission capacity by 60% to reach net-zero emissions in the electric sector by 2050.[3]

FIGURE 1: MAJOR COMPONENTS OF THE ELECTRIC SYSTEM

[i] The Department of Energy defines a circuit-mile as "one mile of one circuit of a transmission line. Two individual 20-mile lines would be equivalent to 40 circuit-miles. One 20-mile double-circuit section would also be equivalent to 40 circuit-miles." See "Quadrennial Energy Review 1.2 Appendix A: Electricity System Overview," 2017. **https://www.energy.gov/sites/prod/files/2017/01/f34/Appendix%20_0.pdf**

CUSTOMER CLEAN ENERGY GOALS

Energy customers have prioritized clean energy procurement in recent years as a key component of their operational and sustainability objectives. In the U.S., energy customers have voluntarily deployed over 47 gigawatts (GW) of renewable energy since 2008.[4] This total accounts for approximately 28% of all existing domestic wind and solar photovoltaic capacity.[5] In 2021 alone, energy customers contracted for 10.6 GW of clean energy, which is the equivalent of 30% of all wind[6] and solar capacity[7] installed that year. Customer procurement grew an additional 11.06 GW in 2021 and customer demand and investment are expected to increase in the coming years. Estimates through 2030 project up to 85 GW of unmet market demand for clean energy from U.S. energy customers.[8]

TRANSMISSION FUNDAMENTALS

TRANSMISSION VOLTAGE AND INFRASTRUCTURE

While both transmission and distribution consist of poles, wires, circuit breakers, and other related equipment, there is an important distinction: transmission operates at higher voltages than distribution. Voltage is analogous to water pressure in a pipe and measures the potential energy of an electric charge.[9] In the U.S., a standard home or commercial business runs on 120 volts and is serviced by a distribution line that typically ranges from 2,400-19,900 volts, or 2.4-19.9 kilovolts (kV).[10] Transmission lines generally operate between 69 kV and 765 kV,[11] as shown in **Figure 2**, and rarely provide direct service to customers but may connect to select large industrial users.

It is essential to control voltage to provide an efficient transfer of electricity. Most generators produce electricity with a voltage below 35 kV, but this level is insufficient to overcome the resistance and power losses that naturally occur when electricity travels over long distances.[12] To mitigate the loss on the lines, transformers are used to *step up* the voltage near a generator before the electricity enters the transmission system and then *step down* the voltage to safe levels for delivery to customers. Many transformers are housed with circuit breakers and other equipment in substations. These are facilities that serve as critical transfer nodes between generation, transmission, and distribution infrastructure.

FIGURE 2:
TRANSMISSION VOLTAGE CATEGORIES

High Voltage	345 kV – 765 kV
Medium Voltage	115 kV – 230 kV
Low Voltage	69 kV – 100 kV

Converter stations are not nearly as ubiquitous as substations, yet they serve an important transmission function by converting the flow of electricity between alternating current (AC) and direct current (DC). Most of the U.S. electricity system operates on AC, meaning electricity changes direction multiple times per second—the rate of which is called frequency—and freely moves over all available pathways rather than directly from generator to customer.[13] This enhances grid flexibility and reliability because electricity follows the path of least resistance and will automatically adjust its route due to line capacity constraints or service disruptions such as downed wires.

In contrast, DC enables the controlled movement of electricity in a single direction from point to point, often over long distances. High-voltage DC (HVDC) transmission lines are more efficient at long distances than comparable high-voltage AC (HVAC) lines because they require less physical space and can experience 30-40% lower energy losses during operation.[14] This efficiency can potentially cover the cost for the construction of converter stations at each end of an HVDC line where it connects to an AC system, but that is dependent on the specifics of individual lines.[15]

TRANSMISSION'S ROLE IN THE U.S. ELECTRICITY SYSTEM

Both AC and DC transmission lines facilitate the movement of electricity across the U.S., which is divided into three structural regions called interconnections or grids. **Figure 3** shows how the Western Interconnection covers all or parts of 12 states from the Pacific Coast to the Rocky Mountains, the Eastern Interconnection covers all or portions of 39 states from the Rockies to the Atlantic Coast, and the Texas Interconnection covers most of the state. Each interconnection is a broad AC network that uses transmission to physically link utilities' local infrastructure to create a massive grid that functions at a synchronized frequency during normal system conditions.[16] The redundant design increases reliability and efficiency by providing multiple pathways for electricity to move within each interconnection.

Moving electricity between interconnections does not occur frequently or easily because limited transfer capacity exists on the boundaries, which are commonly called *seams*. The Texas Interconnection is essentially isolated because there are no transfer points on the seam with the Western Interconnection and the two locations on the Eastern Interconnection seam are not used. In contrast, seven transfer locations are used on the Eastern-Western Interconnection seam that runs from Montana to New Mexico.

At each transfer location, a DC transmission line called a *tie* physically links two interconnections together. When a transfer occurs, grid operators send AC electricity from the first interconnection into a converter station. Next, the electricity is transmitted on the DC line and converted back to AC for transmission in the second interconnection. The use of DC ties enables a high degree of control that can be used to halt a cascading outage event, such as the 2003 blackout that impacted 50 million people, from affecting more than one interconnection.[17]

FIGURE 3: US INTERCONNECTIONS

Despite having the capability to transfer electricity, the seven locations on the Eastern-Western seam only have a combined capacity of 1,320 megawatts (MW),[18] which roughly equals 0.12% of the total utility-scale generating capacity in the U.S.[19] This means transferring substantial amounts of renewable energy across interconnections, such as wind generated in Oklahoma to population centers on the West Coast, is unfeasible unless the existing ties are significantly upgraded or new transfer points are constructed

TRANSMISSION DEVELOPMENT

Recent investment trends demonstrate the growing importance of transmission. Annual utility spending on the transmission system in the U.S. has increased 340% over the past two decades, growing from $9.1 billion in 2000 to $40 billion in 2019.[20] Despite this drastic increase, spending now appears to be leveling off and the number of new projects is decreasing. While the amount of planned transmission across the U.S. and Canada topped 30,000 miles each year from 2011 to 2016, forecasting from 2021 anticipates less than 12,000 planned miles each year from 2023 to 2028.[21]

As with many complex and cost-intensive pieces of infrastructure, transmission faces multiple challenges that inhibit the pace at which it is approved, constructed, and put into service. These barriers align with the four main components, or *4 Ps*, of transmission development: (1) Planning, (2) Permitting, (3) Paying, and (4) Participation.

This Primer will explore transmission planning in greater detail, including project types and planning processes, and how existing challenges impact energy customers.

THE 4 PS OF TRANSMISSION

+ ***Planning*** identifies where and when a transmission line should be built or upgraded. The primary motivations for transmission expansion are to maintain grid reliability, improve the economics of grid operations, and meet public policy goals. This process relies on studies, forecasts, and other inputs to determine the need and cost-effectiveness of proposed transmission infrastructure. Building consensus on a final transmission plan is difficult due to the multiple parties engaged—local, state, and federal authorities may participate in addition to utilities, competitive developers, and planning coordinators—and the lack of a national planning process creates variations across regions of the country.

+ ***Permitting,*** which is often paired with siting, involves securing approvals from the requisite local, state, and federal authorities before construction of transmission infrastructure may begin. Navigating the multiple statutory and regulatory requirements, which form a complicated and at times contradictory patchwork of policies, creates timing uncertainty and frequently delays the already years-long development process.

+ ***Paying*** refers to the method by which the cost of transmission infrastructure is recouped. It is contingent on the regulatory environment where a project is located and the business model of the entity constructing the line. A *merchant developer*, which is an independent, for-profit company unaffiliated with an electric utility, pays for costs by charging voluntary users of the transmission line. Costs incurred by utilities are allocated to end-use customers through cost-of-service regulation.[22] This practice is the most common and attempts to apportion costs commensurate with the benefits each energy customer receives. Determining who should pay for regulated transmission investments, and what portion of costs, is often referred to as the *cost allocation* method.

+ ***Participation*** addresses public engagement in transmission project proposals, and while previously considered part of permitting, is now recognized as a standalone component of the transmission development process.[23] Rising public interest in decarbonization, environmental justice, sustainable land use, and related topics correlates to growing community involvement in transmission infrastructure. Without local stakeholder support, major projects may be denied by policymakers or defeated in public referendums.

TRANSMISSION OWNERSHIP, OVERSIGHT, AND OPERATION

TYPES OF TRANSMISSION OWNERS

The main transmission owner groups are outlined in **Figure 4**. Electric utilities, the entities that deliver electricity to customers, own most of the transmission in the U.S. They include over 60 investor-owned utilities (IOUs), which are private, for-profit companies that serve more than 220 million Americans.[24] The remainder of the country is served by 1,700 public power utilities owned by governmental entities and 900 community-based electric cooperatives owned by participating members.[25]

Utilities are classified into three ownership categories. All utilities are distribution providers, meaning they own local networks to provide electricity directly to end-use customers. A utility may be wires-only, meaning it owns transmission and distribution assets, or *vertically integrated*, signifying it owns generation, transmission, and distribution assets. Most vertically integrated utilities are investor-owned, but some public power utilities and electric cooperatives also own all three components of the electric supply chain. While the majority of utilities own their transmission infrastructure outright, regardless of whether they are vertically integrated or wires-only, on occasion two or more utilities will jointly own a line.[27]

Transcos are the second major category of transmission owners. While many are independent subsidiaries of investor-owned utilities, they may also operate as standalone companies.[28] Transcos create profit by selling transmission service to bulk users of the grid, but unlike utilities, they do not operate any generation or distribution assets.

Merchant developers are the third major category of transmission owners. These are independent, for-profit companies unaffiliated with electric utilities or transcos. Under the merchant business model, developers take a financial risk to build and own transmission used by voluntary customers that pay negotiated rates. As a result, many merchant developers build long-distance

FIGURE 4: TRANSMISSION OWNER GROUPS

Of the roughly 699,662 miles of transmission lines in the United States, investor-owned utilities own 382,295 miles (54.6%), public power utilities own 123,547 miles (17.7%), electric cooperatives own 116,635 miles (16.7%), and transcos and merchant developers own a combined 77,185 miles (11%).[26]

HVDC lines because they can easily control who has access. There is also a market opportunity for merchant developers to build long-distance lines because the complexity and uncertainty of recouping costs from ratepayers across multiple jurisdictions generally disincentivizes utilities from pursuing these types of projects.

SPLIT FEDERAL AND STATE JURISDICTION

Federal, state, and local governments all have varying levels of authority over the grid and the patchwork of jurisdictional oversight can be complicated. The simplest distinction is the bright line that delineates the roles of the federal and state governments based on interstate commerce.[29] Under this precedent, states retain authority over generation, distribution, the siting of transmission infrastructure, and the regulation of final electricity sales to customers because they occur within the boundary of the state. The federal government retains jurisdiction over transmission and wholesale sales of electricity in interstate commerce as well as the operation of related transmission facilities.[ii]

FEDERAL OVERSIGHT OF TRANSMISSION

The primary federal entity with oversight of the electric sector is the Federal Energy Regulatory Commission (FERC). With a broad portfolio that also covers natural gas and oil, FERC is an independent agency that regulates the interstate transmission and wholesale sales of electricity. Notably, FERC's oversight of interstate transmission and wholesale electricity sales only applies to IOUs, not public power utilities or most electric cooperatives.[iii]

FERC has implemented multiple requirements via Order Nos. 890 and 1000 for privately-owned transmission owners to conduct transmission planning, but the agency does not substantively conduct or review planning on its own. Instead, FERC retains regulatory oversight for the U.S.-focused operations of

UNDERSTANDING INTERSTATE COMMERCE AND WHOLESALE ELECTRICITY

Multiple court cases have clarified the federal government has jurisdiction over all investor-owned transmission systems that are physically linked within the Western and Eastern Interconnections.[30]

Every transaction within these regions is deemed to be interstate, and therefore subject to federal oversight, because the grid is capable of transmitting electricity across a state line even if the parties and transmission line(s) involved in a transaction are located in the same state.[31]

[ii] In this context, federal law defines wholesale sales of electricity as the "sale of electric energy to any person for re-sale." See 16 U.S. Code §824(d). Interstate refers to meaning transactions that cross state boundaries.

[iii] Federal law states FERC does not have market-related jurisdiction over electric cooperatives that receive financing under the Rural Electrification Act of 1936 or sell less than 4 million megawatt hours of electricity per year. See 16 U.S. Code §824(f).

the North American Electric Reliability Corporation (NERC), which is a not-for-profit organization that develops and enforces reliability standards for the electric grid in the U.S., Canada, and parts of Mexico.[32] Under federal law and regulations, NERC oversees reliability standards for generation and transmission components of the U.S. electric system operated at 100 kV or higher.[iv]

NERC relies on approximately 80 planning coordinators across North America to implement mandatory standards for transmission system planning.[33] Planning coordinators include regional grid operators in addition to individual utilities that are certified by NERC. Planning coordinators, along with transmission planners, are responsible for maintaining system models, preparing annual planning assessments, conducting near- and long-term performance studies, and conducting contingency analyses within NERC-designated regions.[34] Unlike FERC's regulations for organized wholesale markets and interstate transmission, which only apply to investor-owned utilities, the grid reliability standards promulgated by NERC are applicable to IOUs, public power, and electric cooperatives.[35]

STATE OVERSIGHT OF TRANSMISSION

State oversight of the electric grid resides primarily with public utility commissions (PUCs), which may also be called public service commissions or have a unique name (e.g., Arizona Corporation Commission). While PUCs generally regulate multiple utility industries, such as natural gas and telephone service, their jurisdiction over the electric sector includes setting customer rates, reviewing permitting and siting for generation and transmission infrastructure, and managing the reliability of distribution networks. PUCs may also

regulate public power and electric cooperatives, but there is no universal approach across states. It is not uncommon for public power utilities to be regulated by the corresponding governmental entity (e.g., city council for a municipal system) while electric cooperatives may regulate themselves.

State and local governments retain almost all authority to permit and site transmission infrastructure in the U.S. Approximately two-thirds of states rely solely on PUCs to review transmission projects while the remainder use different entities such as siting boards.[36] States often consider a project's overall need and factors such as the cost, environmental impact, and stakeholder input before granting approval, which is generally done through the issuance of a certificate of public convenience and necessity (CPCN). A CPCN, which is usually required before a developer can exercise eminent domain to secure land for construction, implies the state finds a project is in the public interest.[37]

[iv] The Energy Policy Act of 2005 (Public Law 109–58) directed FERC to create procedures for the development of reliability standards and to define criteria for the establishment of an Electric Reliability Organization (ERO), which is responsible for identifying and enforcing reliability standards in the US. FERC issued Order No. 672 in 2006 outlining rules for certifying an ERO and developing reliability standards. Later that year, FERC certified NERC as the ERO for the United States via Docket No. RR06-1-000.

14

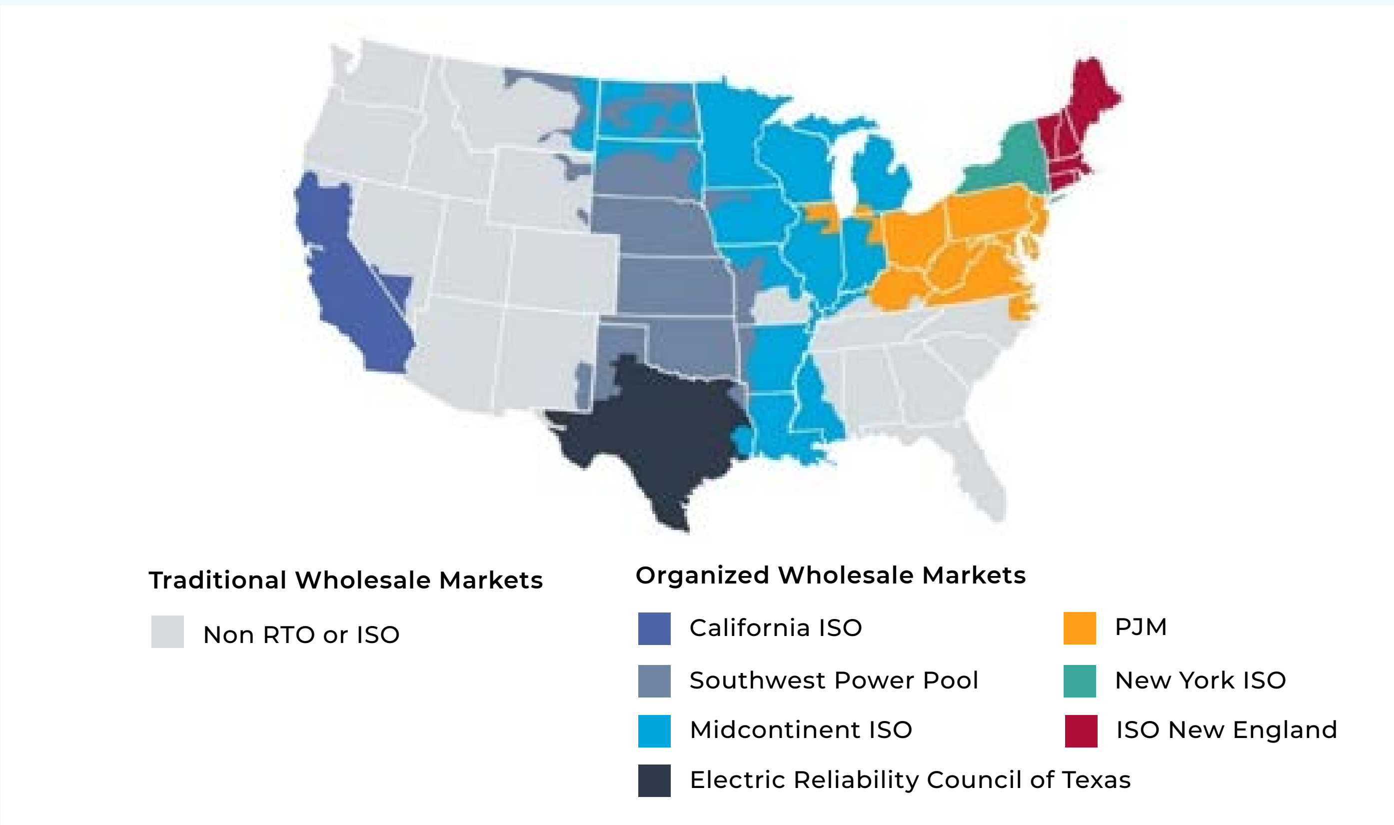
OPERATION OF TRANSMISSION INFRASTRUCTURE

While all transmission infrastructure is owned by a utility, transco, or merchant developer, **Figure 5** shows there are large portions of the U.S. where transmission is operated by non-profit e ntities called Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs). Originally suggested by FERC in the mid- to late-1990s, RTOs and ISOs are formed voluntarily and have essentially the same function despite the naming difference.

Seven RTOs and ISOs run organized wholesale markets that meet customer demand for electricity through competition. Serving roughly two-thirds of the country, RTOs and ISOs balance the supply and demand of electricity by assuming operational control of the generation and transmission assets within their boundaries. RTOs and ISOs vary in size and may cover a single state or multiple states, but each one falls within the structural confines of the three interconnections. Five RTOs and ISOs operate in the Eastern Interconnection, one operates in the Western Interconnection, and one—the Electric Reliability Council of Texas (ERCOT)—is the operator of the Texas Interconnection.

Regions of the U.S. not served by an RTO or ISO, meaning they are not organized, are called traditional wholesale markets. In these non-RTO/ISO areas, which encompass the West and Southeast, each utility owns and operates its individual transmission infrastructure. Despite maintaining sole control of their systems, these utilities, most of which are vertically integrated IOUs, are still structurally linked to each other within their respective interconnection. This enables them to conduct bilateral transactions and send electricity from one party to another, even across the service territories of non-participating utilities.

FIGURE 5: U.S. ORGANIZED WHOLESALE MARKET STRUCTURES



OPEN ACCESS TO TRANSMISSION SYSTEMS

All investor-owned transmission systems used for interstate commerce are required to grant non-discriminatory access to approved grid participants. Congress and FERC developed this policy through a series of laws and regulations, implemented in phases starting in 1992, to create more efficient and lower-cost generation through market competition.[38] Until this action occurred, independent generators could not reach potential customers because vertically integrated IOUs were not required to grant third parties access to their transmission systems.

Open Access Transmission Tariffs (OATTs) ensure open and non-discriminatory transmission access in interstate commerce. FERC developed OATTs through Order No. 888 to define the minimum terms and conditions that owners and operators of transmission facilities used in interstate commerce must follow. FERC created a standard template, called a pro forma OATT,[39] that each transmission owner or operator populates with its specific rates and terms of service. While FERC may grant waivers to the pro forma OATT's requirements in certain circumstances, the general use of OATTs creates a consistent baseline for transmission accessibility. OATTs also ensure third party users can experience the same level of service transmission owners provide to themselves.

The use of OATTs varies by type of organized wholesale market. In non-RTO/ISO regions within the Eastern and Western Interconnections, IOUs that own and operate transmission must file an OATT at FERC that outlines the utility's individual terms and conditions for transmission service. In organized wholesale markets, FERC requires all RTOs and ISOs except ERCOT to have an OATT that sets standard rates and conditions for the use of transmission within the boundaries of the market. While the specifics of an OATT vary by RTO/ISO, its terms apply to all participating IOUs and they are not required to file a separate OATT. Public power and electric cooperatives are not subject to OATTs because they fall outside of FERC's markets-related jurisdiction, but they may file a voluntary OATT to receive reciprocal open access to the transmission systems of FERC-regulated utilities.

Real-time visibility into the electric grid is also critical to ensure open and non-discriminatory transmission access. In Order No. 889, FERC mandated the creation of the Open Access Same-Time Information System (OASIS), which is a nationwide internet-based platform for transmission customers to reserve transmission capacity.[40] OASIS provides information about the availability of transmission capacity IOUs offer via their OATTs and is the platform where transactions are finalized. In organized wholesale markets, RTOs and ISOs receive transmission capacity requests via OASIS and either approve or deny them based on impartial modeling that assesses how each request will impact overall grid operations.[41]

TRANSMISSION PLANNERS AND IDENTIFYING TRANSMISSION NEEDS

There are several entities that conduct transmission planning in the U.S. While the most influential planners are the owners of transmission infrastructure—utilities, transcos, and merchant developers—federal, state, and local governments also participate along with regional organizations. State and local governments have varying levels of engagement in transmission planning, but the role of authorities differs by jurisdiction because there is no universal approach. Energy customers should be aware of the different layers of planning and the roles of each party in their region(s) before engaging in transmissions planning processes.

UTILITY PLANNERS

As the owners of roughly 90% of transmission infrastructure in the U.S., investor-owned utilities, public power, and electric cooperatives are fundamental to the transmission planning process. Most utilities have decades of experience planning, operating, and maintaining transmission within their service territories. However, the scope of utility planning is generally limited because they are naturally incentivized to focus on their individual needs rather than broader network-wide solutions. This is particularly true for an investor-owned utility or its transco subsidiary if new transmission creates more competition or otherwise threatens its business model.

MERCHANT PLANNERS

Merchant developers conduct transmission planning based on a single objective: profit. Unlike IOUs that are obligated to serve a specific service territory, merchant developers seek lucrative projects and recover costs by assessing fees from voluntary users. This means they do not participate in the cost allocation assessments that drive the majority of transmission decisions within the Order No. 1000 regions. As a result, FERC encourages, but does not require, merchant developers to participate in coordinated regional planning processes. However, they are required to share information about the potential reliability and operational impacts of their projects.[42]

REGIONAL PLANNERS

Recognizing that self-interest of transmission owners did not support the development of a holistically designed grid, FERC issued Order No. 890 in 2007 directing all IOU transmission owners to implement a coordinated, open, and transparent transmission planning process. Order No. 1000, issued in 2011, subsequently expanded FERC's directions by requiring all IOU transmission owners to participate in a regional transmission planning and cost allocation process.[43] As a result, there are now 11 FERC-mandated transmission planning regions across the U.S. Six of the regions are RTOs or ISOs while the remaining five regions span non-RTO/ISO parts of the country.[v] However, the transmission planning system remains fragmented as each entity/party is serving their own interest.

[v] ERCOT is not included as an Order No. 1000 region because it is not subject to FERC's planning regulations, but it conducts transmission planning within its intrastate footprint.

MAJOR NEEDS DRIVING TRANSMISSION EXPANSION

When conducting interregional planning, transmission planners primarily consider needs driven by the three factors shown in **Figure 7**: (1) grid reliability, (2) grid economics, and (3) public policy goals. While the scope and sequencing of these needs vary, all planners consider them to some degree to inform the identification and selection of transmission projects.

FIGURE 7: MAJOR TRANSMISSION DRIVERS

Reliability is generally at the forefront of transmission planning due to the electric sector's fundamental responsibility to deliver power at all times. This need focuses on ways transmission can be deployed to ensure the grid continues to operate within set parameters, meets future demand growth, and minimizes the impact of unplanned service disruptions. Compliance with NERC's standards drives many reliability-related transmission decisions, especially when planners anticipate those standards will be violated without the addition of new transmission.[44]

Economic need is based on maximizing the cost efficiency of grid operations by exploring ways transmission can reduce line congestion and integrate lower-cost generation. FERC requires all IOU transmission owners to conduct annual economic planning studies on a regional or aggregated basis that assess the location and magnitude of *significant and recurring* congestion, review possible system enhancements to serve as remedies, and explore costs to identify the lowest-priced option.[45]

Public policy needs derive from laws and regulations at the federal, state, and local levels of government. While always a component of planning due to the highly regulated nature of the electric industry, FERC Order No. 1000 formalized the need for IOUs to consider public policy objectives and requirements during the planning process. FERC implemented this reform to increase the development of more efficient and cost-effective transmission solutions rather than rely on transmission owners who often prioritize their own needs.[46]

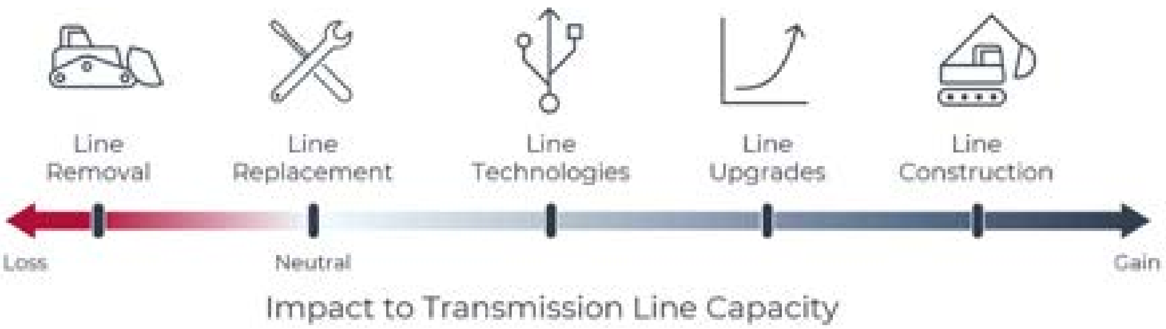
A 2021 assessment of the factors driving future transmission expansion in North America shows reliability accounts for 64%, renewable integration is 11%, economics and congestion are a combined 10%, and other factors account for the remaining 15%.[47]

TRANSMISSION PROJECTS AND CONSTRUCTION

Types of Transmission Projects

Transmission development, which is conducted by utilities, transcos, and merchant developers, includes five types of projects: (1) removal of an existing line, (2) end-of-life replacement of an existing line to maintain system capacity, (3) deploying technologies on existing lines for greater efficiency, (4) upgrading an existing line to a higher capacity, and (5) new construction, which includes the extension of an existing line. **Figure 8** shows the range of impacts each project type creates. While line removal lowers system capacity and line replacement maintains the status quo, the remaining three project types bring differing degrees of operational benefits to the electric system.

FIGURE 8: TRANSMISSION PROJECT TYPES AND IMPACT



Grid-enhancing technologies (GETs) are a cost-effective way to amplify the performance of existing transmission. Examples of GETs include advanced power flow controls, which reduce line congestion by using voltage to quickly redirect electricity to less-utilized pathways, and dynamic line ratings that maximize line capacity based on real-time weather and operational conditions.[48] Deploying GETs may be a permanent solution to improve line performance or serve as a temporary stopgap measure until new lines are built.[49]

An approach related to GETs is the deployment of non-transmission alternatives, which planners must consider under the requirements of FERC Order No. 890. These are existing grid resources such as energy efficiency and energy storage that can be used to delay or reduce the size of new transmission lines. The strategic application of non-transmission alternatives can even drive down the total cost for new transmission lines by providing cost-effective alternatives.[50] Despite these benefits, GETs and non-transmission alternatives alone will not fully address the need for additional transmission to meet continued customer demand for clean energy. Line upgrades and new construction are the most substantive methods to move large-scale renewables to customers, even if they are also the most complex, time-intensive, and expensive options available to transmission planners.

Cost Factors Influencing Transmission Projects

When assessing a transmission line's total price tag, developers consider three broad cost categories: (1) wires, (2) support structures, and (3) land acquisition.[51]

Wire costs are affected by the voltage and length of a transmission line. Higher voltage projects generally require advanced or higher gauge wire, the latter of which can be double or triple the cost for a 1,000-ft. section when compared to a lower gauge.[52] A line's placement, meaning overhead or underground, is another major cost consideration. Underground wires are often used in dense urban areas and other settings where it is preferable or necessary to bury wires. While this can mitigate weather-related outages and provide other reliability benefits, constructing underground transmission requires more materials, causes greater disruptions, and is more complex. This often makes it anywhere from two to nine times more expensive to build than a comparable overhead line.[53]

The costs associated with support structures and land acquisition are also influenced by a line's voltage. Lower voltage transmission lines may be conveyed by wood or steel poles while high-voltage lines require massive lattice towers supported by foundations. The width of land below a transmission line, known as a right-of-way (ROW), is dependent on a line's capacity and may span anywhere from 80 feet for a 69 kV line to 200 feet for 500 kV line.[54] Procuring a ROW can be costly if the proposed line passes through expensive property near urban centers or lucrative agricultural zones. While rural areas may be more affordable to procure, grading and clearing remote land to prepare it for transmission construction may still be costly, especially if the ROW crosses a wetland or densely forested, hilly, or mountainous terrain.[55]

ASSESSING CURRENT TRANSMISSION PLANNING PRACTICES

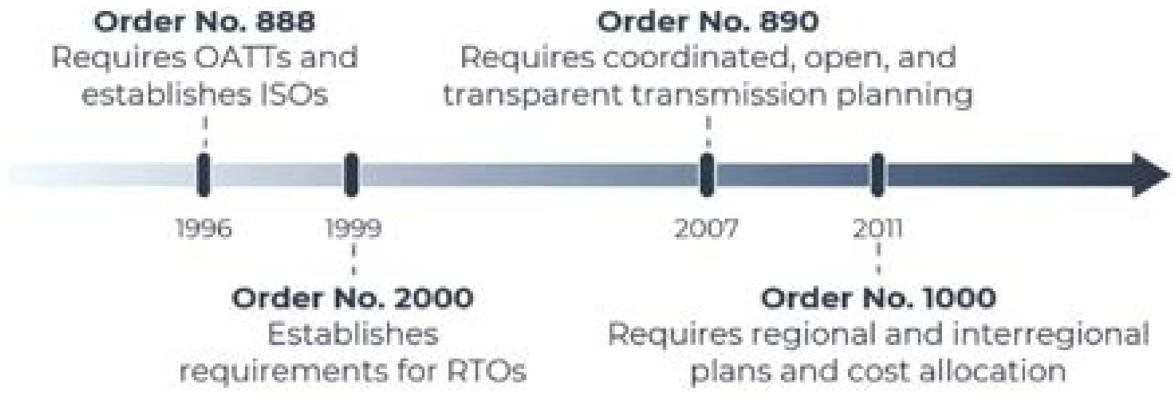
FEDERAL TRANSMISSION PLANNING POLICIES

FERC's regulations, shown in **Figure 9**, are a key force driving current transmission planning in the U.S. Order No. 890, issued in 2007, was the first major step to enhance transmission planning as it directs investor-owned transmission providers and RTOs/ISOs to follow nine transmission planning principles that include coordination, openness, transparency, and information exchange.[56] It also requires all investor-owned transmission providers and RTOs/ISOs to implement a coordinated, open, and transparent transmission planning process.

Under the rule, IOUs and RTOs/ISOs must give stakeholders the opportunity to provide early input on transmission plan development while also disclosing sufficient planning studies. Order No. 890 also acknowledged that RTO/ISO planning processes are significantly more open and transparent than those used by vertically integrated utility transmission providers in non-RTO/ISO regions.[57]

Order No. 1000 expanded on Order No. 890 by instituting new regulations for regional and interregional transmission planning and cost allocation. FERC requires each investor-owned transmission provider and RTOs/ISOs to participate in a regional transmission planning process that satisfies the nine planning principles, and produce a regional transmission plan with cost allocation that includes the economic planning studies as defined in Order No. 890. Lastly, local and regional transmission planning processes are required to consider transmission needs driven by public policy requirements established by state or federal laws and regulations.

FIGURE 9: MAJOR FERC TRANSMISSION PLANNING ORDERS



TRANSMISSION STUDIES AND ANALYSES

Much of the transmission planning process relies on assessments gauging a variety of factors. These primarily focus on how new projects can address system reliability and economic needs, but they also include studies that are conducted during the development of specific transmission projects. Examples include:

- ***Load forecasting*** is one of the major studies used in transmission planning. This analysis relies on models to assess potential changes in customer demand within an RTO/ISO or the service territory of a vertically integrated utility. Understanding anticipated changes to overall use of the grid enables planners to determine if, where, and when new transmission capacity is needed to ensure system reliability. Unlike short-term forecasting, which is used to ensure the reliable operation of the electric grid on a daily basis, long-term forecasting typically ranges from 10 to 20 years into the future and is focused on serving all existing and projected load growth.

- ***Economic studies*** consider how new transmission projects can lower costs or otherwise create efficiencies on the electric grid. Order No. 890 requires all IOU transmission owners to conduct annual economic planning studies on a regional or aggregated basis. These studies assess the location and magnitude of significant and recurring congestion, review possible system enhancements to serve as remedies, and explore costs to identify the lowest-priced option. FERC does not require the use of any single metric or group of metrics and the scope of each study varies by region.

- ***An environmental impact statement*** (EIS) reviews how major infrastructure projects will affect the surrounding environment. They are often mandated by federal and state law for significant projects, but the exact threshold varies by jurisdiction and is usually contingent on a transmission project's size, location, and other factors. An EIS often reviews a project's effect on a variety of issues, such as endangered species habitats, and considers alternatives or mitigation measures to reduce a project's potential impact to the environment. The results from an EIS influence a transmission line's route and are often a determining factor in whether a developer receives permission from state and federal authorities during the permitting and siting process.

LOCAL PLANNING

Transmission planning at the local level assesses the transmission needs within a utility's individual retail distribution service territory or footprint. Prior to the development of the Eastern and Western Interconnections that physically link service territories together across multiple states, transmission lines infrequently crossed state borders. While interstate transmission is now commonplace, most transmission lines continue to be developed and owned by local IOUs operating under cost-of-service rates. Under this model, IOUs recover the costs of constructing transmission infrastructure while also earning an approved rate of return for their shareholder investors.

Demonstration of need is a key component of local planning. This often occurs through the analysis and recommendations conducted during the state-regulated integrated resource plan (IRP) process. An IRP is a multi-year strategy IOUs submit to PUCs outlining how they will use their generation, transmission, and distribution assets to meet forecasted customer demand. Reliability is a major driver during the IRP process and utilities also account for it while planning transmission in the parts of their service territories that fall within the regional boundaries of a NERC planning coordinator. Utilities work closely with NERC planning coordinators to integrate their individual planning processes into broader plans and ensure compliance with NERC's mandatory transmission planning requirements.

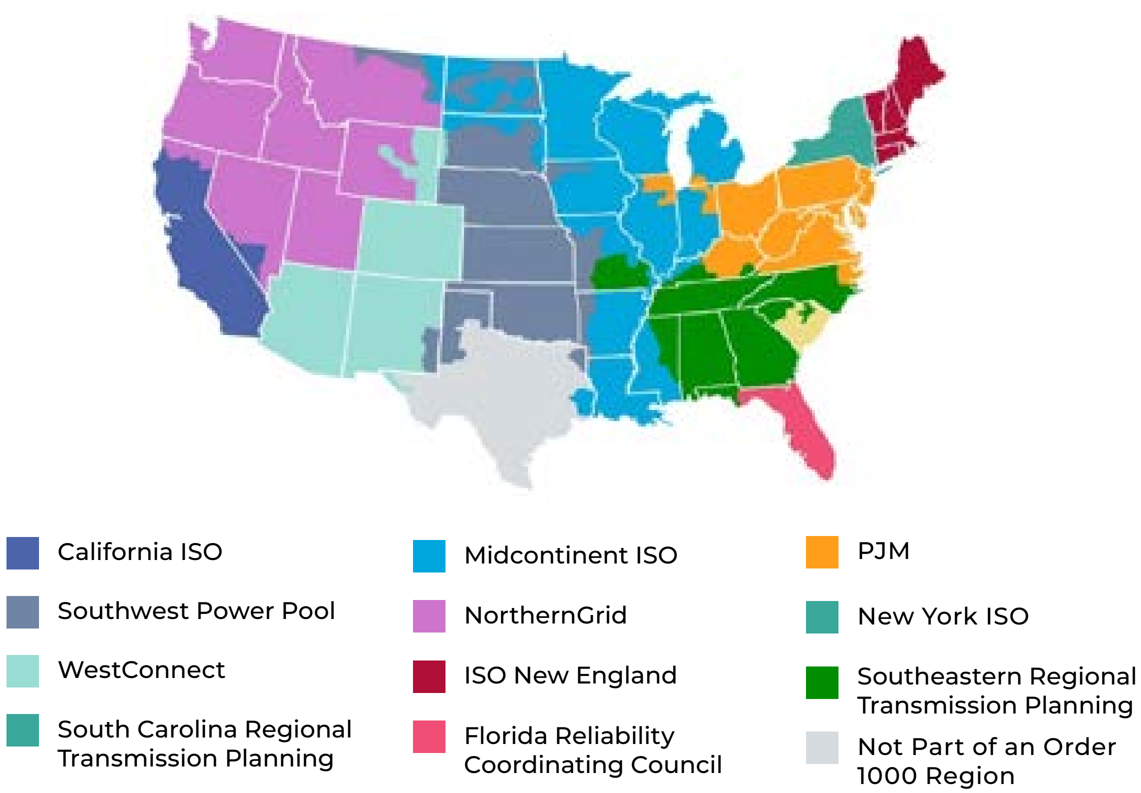
While there is no national standard outlining the differences between local and regional transmission projects, four considerations apply: voltage, reliability, maintenance, and benefits. Local transmission projects are usually low voltage, only address the reliability of the transmission owner's local system, focus on the maintenance or replacement of lines within the owner's local system, and do not provide substantive regional benefits.[58] This is an important distinction to make because utilities are naturally incentivized to prioritize their own needs and prefer local transmission projects because they are exempt from competitive planning under Order No. 1000. Data from 2013-2017 show an average of 47% of all transmission investments across five RTOs/ISOs occurred outside of the full planning process.[59] This correlates with additional data that anticipate roughly 40% of North American transmission lines planned through 2030 will only be between 10 and 50 miles in length.[60]

REGIONAL PLANNING

Transmission planning at the regional level is conducted within the 11 regions FERC established via Order No. 1000. As shown in **Figure 10**, five of the regions span non-RTO/ISO parts of the country while the remaining six are RTOs/ISOs.[61] ERCOT is not counted as an Order No. 1000 region because it is an intrastate transmission system and FERC therefore does not have jurisdiction. The Order No. 1000 regions are also separate and distinct from the NERC planning coordinator regions discussed above, although there may be some overlap. This setup can hamper the development of the most efficient planning solutions because some NERC-related reliability projects are established outside of the Order No. 1000 planning process.

In Order No. 1000's non-RTO/ISO transmission planning regions, IOUs conduct local transmission planning focused solely on their individual service territories with oversight from state PUCs. The transmission plans in each IOU's IRP serve as small building blocks that are combined to form a baseline regional transmission plan. The Order No. 1000 planning entity, which is usually sponsored by participating IOUs, then uses the joint plan to evaluate and compare alternative transmission proposals that might be more efficient or cost-effective than the rolled-up approach.[62]

FIGURE 10: FERC ORDER NO. 1000 TRANSMISSION PLANNING REGIONS



24

Local planning also shapes the regional process used in RTOs/ISOs, but not nearly to the same degree. RTO/ISO planning is broadly recognized to be more transparent, participatory, and systematic than the method used in regions dominated by vertically integrated IOUs.[63] With multiple parties owning generation, transmission, and serving customer demand, the RTO/ISO planning process incorporates input from a broad group of stakeholders. This engagement can more easily identify efficiencies that benefit the entire system and fosters the development of holistic, region-wide transmission solutions.

Regional planning by RTOs/ISOs is generally comprehensive, but the process does have shortcomings. One of the biggest is the lack of mandatory participation by transmission owning utilities other than IOUs. Merchant developers are only required to share information about the system impacts of their projects, not to coordinate project development, while public power and electric cooperatives are usually excluded from regional planning unless they voluntarily enroll in an Order No. 1000 region.[64] RTO/ISO treatment of local projects, especially those required to address the reliability, resilience, and maintenance of a transmission owner's local system, enables utilities to bypass broader regional review. For example, in 2020, PJM's board approved 43 regional reliability projects valued at $413 million while the total value of local projects neared $3.2 billion.[65]

The challenges in non-RTO/ISO planning regions are more complicated and substantial. Local transmission plans are the building blocks for broader system interconnections, but they are often too myopic to meet the long-term needs of the region. They act solely as one-way inputs and cannot be substantively modified by the Order No. 1000 planning entity if an alternative regional solution is identified.[66] IRPs further exacerbate this balkanization because transmission approved during a PUC's review is usually deemed to meet required reliability and public policy objectives. However, the criteria used to judge those needs are only applicable to one state, not the entire region.[67]

INTERREGIONAL COORDINATION

In Order No. 1000, FERC directed each pair of neighboring transmission planning regions to establish processes for identifying and evaluating potential interregional transmission projects. The Commission sought to encourage the planning regions to identify transmission lines that may be more efficient or cost-effective solutions to address regional needs. FERC also requires the same planners to set up a method of allocating the costs of interregional transmission projects that are selected in these processes. Like local and regional transmission, interregional projects may be for reliability, market efficiency, and/or public policy needs.

Each of the 11 Order No. 1000 planning regions have established transmission coordination processes with one or more of their neighboring regions. The majority of these processes involve pairs of neighboring regions, but there are two instances of trilateral engagements. The first is between ISO-NE, NYISO, and PJM while the other involves all three regions in the Western Interconnection: CAISO, NorthernGrid, and WestConnect.

Despite these new processes, interregional coordination is still limited. Mismatches in project types, benefits calculations, and modeling, assumptions, and baseline criteria inhibit the ability of different regions to fully realize the potential of interregional planning.[68] While MISO and PJM have worked collaboratively to develop several lines that resolve targeted market-to-market congestion through the Joint RTO Planning Committee (JRPC) and the Interregional Planning Stakeholder Advisory Committee (IPSAC), they have struggled to develop interregional lines that reduce congestion more broadly in each market or address needs like public policy.[69]

The ongoing lack of interregional planning limits the ability of grid operators to take advantage of diverse geographic resources that could result in lower energy costs while also increasing interregional reliability.[70] Efforts for interregional coordination are essentially stalled even as advocacy grows for a macrogrid, which would establish a network of high-capacity, long distance lines across the U.S. to significantly enhance the balancing of resources regardless of location.[71] However, existing planning processes are unable to support the development of a macrogrid and leadership from Congress, FERC, or the U.S. Department of Energy may be necessary.

ELEVATING THE CUSTOMER VOICE

CURRENT TRANSMISSION PLANNING CHALLENGES

In recent years, there has been growing consensus that current transmission planning policies have become insufficient t o a ccommodate 2 1st century grid operations, clean energy goals, and customer needs. Local, regional, and interregional transmission planning all face different obstacles, but across transmission planning efforts generally, there are consistent themes.

TRANSMISSION PLANNING BARRIERS INHIBITING CUSTOMER CLEAN ENERGY GOALS

Energy customers rely on transmission to access renewable generation sources, but the lack of adequate infrastructure inhibits the ability to fully realize their clean energy goals. Current procurement challenges include congestion on lines with low capacity, which results in higher prices for clean energy, and limited or reduced

1. **Planning Is Reactive and Does Not Fully Consider Transmission Drivers**
   Current planning often begins with utility forecasts for future generation demand that do not fully capture the changing resource mix to meet shifting energy customer demands.

2. **Planning Is Siloed by Project Type and Utility Service Territory**
   Transmission planning that considers reliability, economic, and public policy as separate buckets can fail to capture opportunities to maximize several types of benefits at once

3. **Backlogs Are Significantly Delaying the Connection of New Generation Sources**
   Data estimates more than 700 GW of proposed generation is waiting in backlogged queues across the U.S., the majority of which are new wind, solar, and storage projects.[72]

4. **Methods to Determine Who Pays for Transmission Do Not Fully Account for Benefits**
   Planning does not adequately consider a project's benefits and costs are often placed on specific stakeholders, increasing the likelihood of opposition despite having a clear need.

5. **Stakeholder Processes and Governance Are Outdated**
   Methods that give stakeholders a voice and opportunity to engage in transmission planning are outdated in RTO and ISO regions and incredibly insufficient in non-RTO/ISO regions.

access to existing carbon-free generation due to line constraints. Insufficient transmission can also delay the timely start of new carbon-free resources because they are unable to connect to the grid.

Despite customer-driven investment in extensive amounts of clean energy for more than a decade, many transmission planners continue to exclude energy customer demand from the planning process.[73] This oversight has potentially substantial impacts to the grid because the 40+ GW of renewable energy procured by customers through 2021 is greater than the combined generation nameplate capacity of 10 states.[vi] Continuing to omit customer demand from transmission planning risks missing significant opportunities to enhance grid operations and create long-term cost savings across the electricity system. It is also indicative of a larger trend where siloed, reactive planning fails to anticipate future grid needs proactively and holistically.

Transparency and stakeholder engagement are essential to successful long-term transmission planning. However, many planning processes do not provide adequate public information or opportunities for engagement. For example, approximately 50% of the transmission investments made from 2013 to 2017 in planning regions covering two-thirds of Americans occurred without significant stakeholder input.[74] Incorporating additional opportunities for the impartial review of transmission proposals, as well as forward-looking planning, can increase cost-effectiveness by using greater economies of scale, encouraging the deployment of grid technologies as alternatives to new lines, and avoiding the installation of inefficient infrastructure. Additionally, greater customer participation during the planning process can also lower the likelihood of public opposition to a project.

LEVERAGING THE CUSTOMER VOICE IN POLICY DISCUSSIONS

FERC's 2021 Advance Notice of Proposed Rulemaking, which focused on developing more holistic transmission planning, cost allocation, and generator interconnection processes,[75] created an opportunity for energy customers to substantively engage on transmission planning policies. In response, the Clean Energy Buyers Association submitted comments advocating that any reforms to transmission planning should account for (1) an improved coordination process, (2) transparency, (3) cost effective solutions, (4) resource adequacy, (5) transmission capacity adequacy, (6) a flexible and dynamic market, and (7) reliability.[76]

Energy customers can continue to leverage their voice at FERC to support reforms that will overcome the planning challenges introduced in this Primer. Future improvements to RTO and ISO stakeholder processes and governance may also create opportunities for greater collaboration between customers and transmission planners in the future to ensure customer clean energy demand is meaningfully considered as a driver for new transmission. More holistic planning, efficient generation interconnection queues, and new methods for cost allocation can also reduce barriers to transmission expansion. Energy customers in non-RTO areas should consider the challenges of implementing these reforms within the current regulatory structure and the value the development of an RTO/ISO structure may bring.

Transmission planning is one of the key customer priorities for grid decarbonization, but significant reforms must occur to achieve grid expansion efficiently.[77] Resolving the issues currently facing transmission planning is foundational to facilitating the type of transmission investments that are essential to a reliable, affordable, decarbonized, and forward-facing electric grid.

[vi] Data from the Energy Information Administration show the electric power industry's combined nameplate capacity in Alaska, Delaware, Hawaii, Idaho, Maine, Montana, New Hampshire, Rhode Island, South Dakota, and Vermont totals 39.9 GW. See "Existing Capacity by Energy Source, by Producer, by State," 2020. **https://www.eia.gov/electricity/data/state/existcapacity_annual.xlsx**

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CEBI
CLEAN ENERGY
BUYERS INSTITUTE

Address
Clean Energy Buyers Institute
1425 K St. NW, Suite 1110, Washington, DC 20005

Phone
1. 888. 458. CEBI

Email / Web
info@cebi.org
www.cebi.org