# Transmission in the United States

## What Makes Developing Electric Transmission So Hard?

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# Contents





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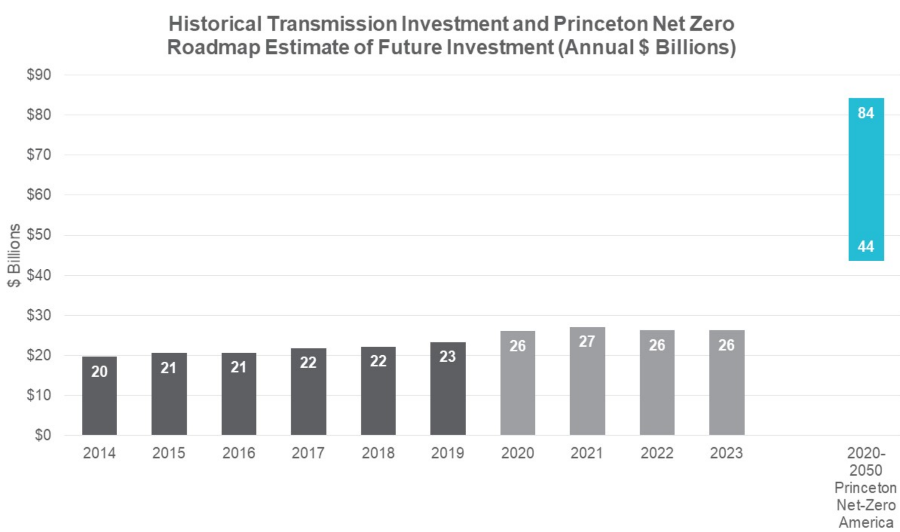
## INTRODUCTION

States, cities, utilities, corporations, and others are committing to various clean energy and carbon-reduction goals (e.g.,100% renewables, 100% carbon free, net zero) that will require enormous changes to the electricity grid. In addition, President Biden has announced a goal of carbon-free electricity by 2035. What will it take to meet these targets?

> **Less Than 10% of Transmission Line Miles Added Since 2013**
>
> Of the 180,000 miles of transmission in service today, less than 14,000 have been placed into service since 2013. Only 32 of the 255 projects making up that total were greater than 100 miles long.

A large part of the answer involves the addition of more high-voltage transmission. (Obviously, building new sources of electric generation is another major part of the answer.) Transmission is critical because it connects generation to load, and considerably more transmission will be needed to integrate the renewables necessary to meet clean energy goals. In fact, studies suggest that the capacity of the nation's transmission system may have to be doubled to meet President Biden's goal. Recent experience suggests that this will be challenging. The chart below provides one estimate of the transmission investment needed to meet net-zero goals for the power sector by 2050.

Figure 1.1 – Difference Between Historical Transmission Investment and Implied Need to Meet Clean Energy Goals[1]




***Can sufficient transmission be planned and built in time to meet these clean energy goals? Based on the policies that govern transmission development today, the likely answer is no.***

This paper highlights many of the reasons why expansion of the transmission system will be problematic, especially within a relatively short period of time. It is beyond the scope of this paper to speculate on whether or how policies might be changed to enable expansion of the transmission system.

[1] Edison Electric Institute; Princeton Univ., Net-Zero America: Potential Pathways, Infrastructure, and Impacts (Dec. 15, 2020), at pp. 138-39, 170-71; J.P. Morgan Asset and Wealth Management, 2021 Annual Energy Paper (May 2021). Note: Historical transmission investment is for investor-owned utilities. 2020 figure is preliminary.

***Transmission will be a key enabler of the transition to a net-zero power sector. These challenges will have to be addressed if we're to develop the transmission system needed for an orderly clean energy transition.***

### Transmission Planning

Because transmission connects generation to load, as generation sources and loads change, the system must adapt as well. Planning must accommodate changes to the physical grid as well as the interests of myriad stakeholders. It balances policy needs, reliability, and cost concerns. **The integration of large amounts of intermittent renewables across regions will require interregional processes to address these priorities; those processes are in their infancy today.**

### Cost Allocation

Allocating the cost of transmission is difficult because it is a networked system serving many stakeholders and meeting various needs. The transmission grid provides reliable power, enables integration of renewables, and provides access to the least cost generation. **Figuring out who pays is complicated; it becomes more so with longer interregional projects.**

### Siting and Permitting

The states, and sometimes municipalities and counties, approve the siting of transmission. If the facility crosses federal land, federal agencies become involved. **Each entity has its own process, and each can halt or delay a project.** Stakeholders have the opportunity to protest at many points in the process.

### Transmission Interconnection Queues

The processes that RTOs and ISOs use to interconnect generation were developed for large, central station power plants. **These processes don't easily accommodate much smaller, intermittent generation resources and as such have bogged down.**

### Ratemaking and Incentives

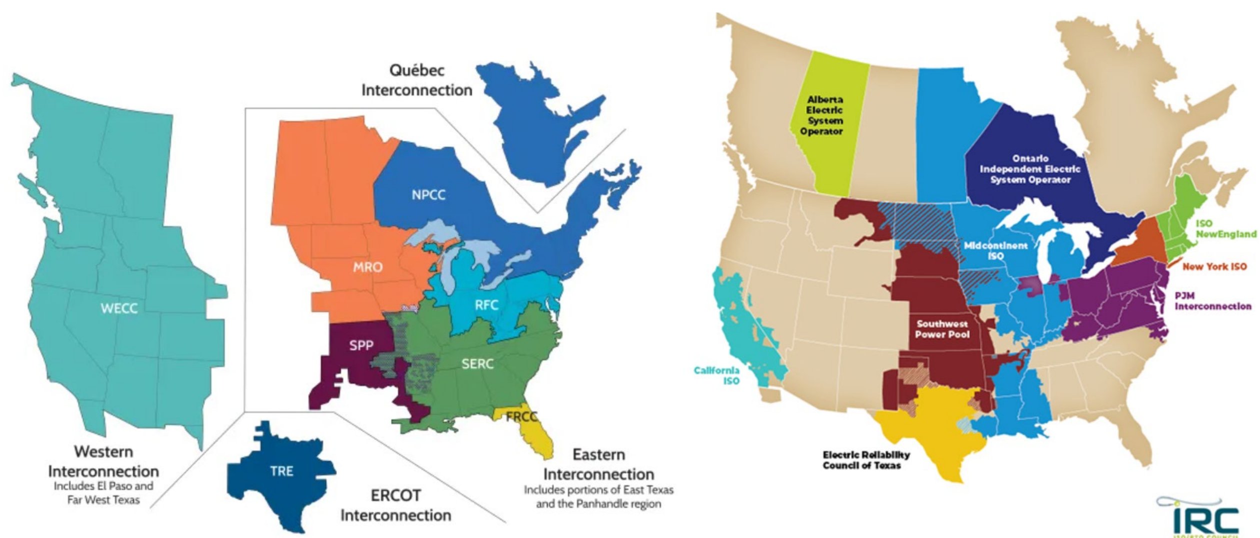
The rates charged for transmission access are set by FERC. FERC also has the ability to grant incentives (i.e., enhanced ROE) based on project or company characteristics. **It is unclear how FERC may use incentives policy to support the clean energy transition.**

### Overview of the U.S. Transmission System

The U.S. transmission system is comprised of 180,000 miles of high-voltage transmission lines and 55,000 substations connecting 7,000 power generators to loads in population centers across the country.[2] The system is made up of three different interconnections that are largely independent with limited power transfers among them: the Eastern Interconnection, the Western Interconnection, and the Electric Reliability Council of Texas (ERCOT).

Transmission is planned and developed at the regional level, and many of its challenges are inherently regional. Each location has its endowment of existing infrastructure (including generation and transmission), demand centers, customer types, renewable resource potential, and potential risks from widespread resilience events. Moreover, states have a meaningful role in siting and permitting electric facilities, mandating renewables procurement, and enabling cost recovery. Indeed, different states are forcing the issue on renewables integration as they announce aggressive clean energy and net-zero goals. As the need for integration of renewables and access to low-cost energy resources grows, the need for interregional transmission is increasing. Renewables are not evenly distributed; they are concentrated in various regions which do not necessarily align with where the greatest needs are emerging.[3]

Figure 1.2 – Interconnections, NERC Regions, and ISO/RTO Territories[4]



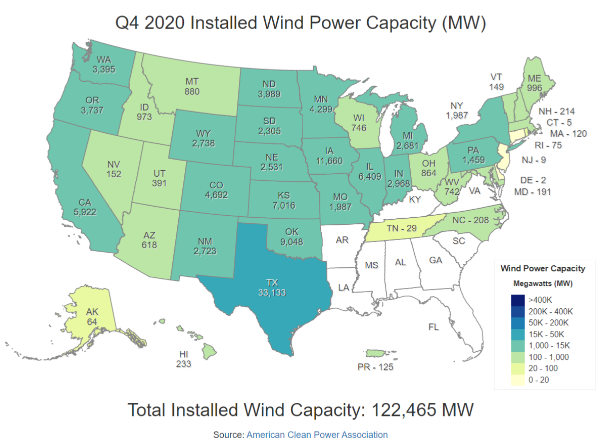

[2] U.S. Department of Energy, United States Electricity Industry Primer (July 2015), available at https://www.energy.gov/sites/prod/files/2015/12/f28/united-states-electricity-industry-primer.pdf
[3] WIRES, Informing the Transmission Discussion (Jan. 2020), prepared by ScottMadden, Inc., at p. 16 (WIRES Report)
[4] ISO/RTO Council (https://isorto.org/)

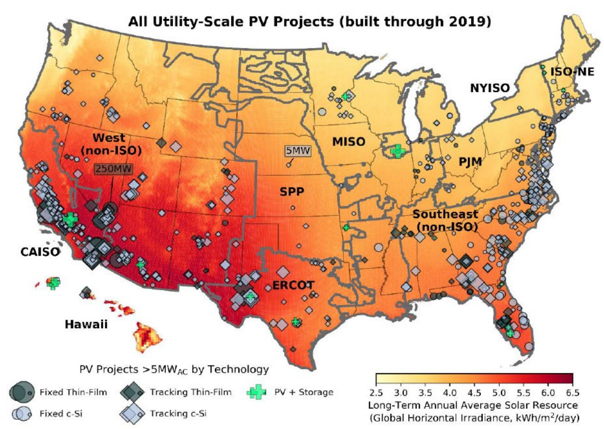
## Proliferating Clean Energy Goals and Resources

Eighteen U.S. states and territories have adopted mandates[5] to achieve 100% clean energy, with some setting targets as early as 2030. Further, electric utilities have also made their own clean energy commitments, and corporate buyers are increasingly making voluntary commitments to purchase renewable energy. More recently, the Biden administration announced a goal to achieve 100% carbon-free electricity by 2035.[6]

The location of renewable resources is important in considering these proliferating goals. Wind speeds and solar irradiance dictate, in large part, the location for development of these resources. As the maps below show, recent development of these respective resources is concentrated in different regions. Solar development has been concentrated in California, the Southwest, Texas, and increasingly in the Southeast. Wind has historically been concentrated in the Plains, upper Midwest (including around the Great Lakes), and Texas, although increasing development is occurring in the Mountain West, New York, and New England.[7]

Figure 1.3 – Wind and Solar Resource Locations and Locations of Installed Power Capacity[8]




Renewable portfolio standards (RPS)—in particular the potential mismatch between renewable resource demands in RPS states and available supply within a particular state's borders—may further indicate where new transmission capacity may be needed in the future. As clean energy goals advance at the state and utility levels and renewables development is mixed and geographically diverse, RPS supply-demand "imbalances" are potential indicators of increased needs for import and export capability across regions.

[5] Mandates include executive orders and other measures besides legislation.
[6] The White House, "Fact Sheet: The American Jobs Plan" (Mar. 31, 2021). The administration has also discussed an interim target of 80% clean energy by 2030. See Reuters, "White House backs 2030 milestone on path to net zero grid" (Apr. 26, 2021), at https://www.reuters.com/business/sustainable-business/exclusive-white-house-pushing-80-clean-us-power-grid-by-2030-2021-04-26/.
[7] WIRES Report, at p. 29
[8] WindExchange, U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy (available at https://windexchange.energy.gov/maps-data/321) and Lawrence Berkeley Laboratory (available at https://emp.lbl.gov/utility-scale-solar)

In addition to the rapid deployment of variable renewable generation resources, there are other factors causing disruptions to the electric grid:

- **Conventional thermal power generation retirements:** NERC estimates that approximately 39 gigawatts (GWs) of coal-fired, 13 GWs of natural gas-fired, and 1.1 GWs of nuclear power capacity have retired since 2013. It also notes the announced retirement of nearly 27 GWs of generation through 2028. Bloomberg estimates, based on announced comments to date, that 35 GWs of coal capacity could retire between 2019 and 2025.
- **Shift to gas:** The electric system has long relied on large, central station generation. As those units have aged and natural gas prices have made it more attractive as a fuel, they are being replaced with gas-fired units.
- **Potential resilience and reliability impacts:** Increased reliance on natural gas may have reliability and resilience effects. Some regions have significant penetration of natural gas capacity as a percentage of total capacity. More than 50% of capacity in California, Texas, Florida, New England, and the Desert Southwest, for example, is natural gas-fired.[9] Industry and regulators continue to examine fuel assurance and the impact of potential gas disruptions.[10]
- **Reconfiguring the grid:** NERC has noted that generation retirements near large load centers with limited transmission import capability pose the greatest potential risk to reliability, unless replaced with plants in the same vicinity. Voltage issues could arise with increased imports, and reliability coordinators and system operators are analyzing these potential impacts as units retire.[11]

**Operational Effects of Increasing Variable Energy Resources**

Wind and solar generation have different performance profiles from traditional fossil-fired or nuclear power generation. Solar power is usually coincident with warm season peak demand, but production falls off in early evening as the sun sets. Large-scale solar photovoltaic typically has a capacity factor of 21% to 34%. Wind is most productive at night and in the winter, with a capacity factor ranging from 38% to 55%. Performance of both types of resources varies from season to season. Geographic dispersion can smooth some of this variability. However, absent large-scale battery storage and demand response resources, balancing the system today requires available-on-demand thermal generation.

**The ability to integrate variable resources and manage geographically dispersed generation is entirely dependent upon transmission infrastructure.**

The combination of the challenges listed above and the introduction of growing amounts of renewable resources have focused policymakers, grid operators, and planners on how those resources perform and what modifications may be needed to maintain grid reliability and resilience. In nearly all cases, additional transmission capacity is considered part of the solution.

[9] See, e.g., NERC, 2020 Long-Term Reliability Assessment (Dec. 2020)
[10] A number of studies of impacts of gas-power interdependence and potential precautionary steps have been conducted over the past several years, including post hoc analyses of particular events. Some examples include the following: 2019 FERC and NERC Staff Report, The South Central United States Cold Weather Bulk Electric System Event of January 17, 2018 (July 2019); Nuclear Energy Institute, The Impact of Fuel Supply Security on Grid Resilience in PJM (June 8, 2018); and NERC, Special Reliability Assessment: Potential Bulk Power System Impacts Due to Severe Disruptions on the Natural Gas System (Nov. 2017). This interdependence and the broader issue of reliability remains a subject of discussion among industry and regulators. See NERC Press Release, "Electric–Gas Interdependencies, Potential Summer Energy Shortfalls are Focus of Board Discussions" (May 13, 2021).
[11] WIRES Report, at p. 26

### Fundamental Challenges to Transmission Development

As we will describe in this paper, transmission projects continue to be very difficult to build in the United States. From their conception in the various planning processes used by regions to identify the projects through construction and energization, transmission faces myriad hurdles. We will examine the challenges at each stage of the transmission project lifecycle:

- Transmission Planning
- Cost Allocation
- Transmission Interconnection Queues
- Ratemaking and Incentives
- Siting and Permitting

## TRANSMISSION PLANNING

### Key Takeaways

- Transmission planning is a critical step because it identifies the transmission system upgrades that are necessary to ensure reliability, mitigate congestion, or achieve public policy goals, such as the addition of more renewables to the grid.
- Federal Energy Regulatory Commission (FERC) Order 1000, issued in 2011, is the basis for the transmission planning processes that exist today.
- This order established the requirements by which FERC-jurisdictional entities plan their transmission systems. Implementation of these requirements is carried out within regions.
- Despite their importance in integrating large-scale renewables, interregional planning processes remain underdeveloped and inadequate to develop a multi-regional grid connecting renewable energy resources and load centers.
- There is no mechanism today to enable the type of national planning many believe is needed to facilitate integration of large amounts of renewables between regions and across interconnections.

### The Role of Transmission Planning

***"Transmission planning is characterized by a large number of choices with multiple dimensions, a great deal of uncertainty, large investments, and long periods over which investments must be assessed."***[12]

The primary objective of transmission planning is to ensure grid reliability (enough transmission to move energy reliably where it is needed). In planning, a transmission owner or operator looks at long-term demand (load) trends and anticipated generation/resource additions. It then identifies grid improvements that cost effectively maintain reliability and adequate energy for customers. Transmission planning is typically limited to voltages above 100 kV.

In considering reliability, planners look at the impact to grid operations of the loss of one or more critical components of the bulk power system (contingencies). This may be the loss of a large generator, a substation, or a key transmission line. Those contingencies may cause power lines to be overloaded, instability in the grid, and/or power to be undeliverable to customers.

Transmission owners and operators also study discrete issues that pose potential risks to the transmission system. These may include issues like weather events and resilience impacts, geomagnetic disturbances, effects of increasing levels of variable renewable resources,[13] and effects of distribution grid modernization, electrification, distributed energy resources, and variable load (e.g., programs to reduce consumption at peak times) on the transmission grid. While these studies inform the planning process, they do not lead directly to transmission projects.

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[12] MIT, The Future of the Electric Grid (2011), at p. 86

[13] Midcontinent ISO (MISO), for example, recently published a Renewable Integration Impact Assessment, "highlighting impacts of renewable energy growth in MISO over the long term. This assessment provided technically rigorous, concrete examples of integration issues and examined potential solutions to mitigate them." See https://www.misoenergy.org/planning/policy-studies/Renewable-integration-impact-assessment/#nt=%2Friiatype%3AReport&t=10&p=0&s=Updated&sd=desc

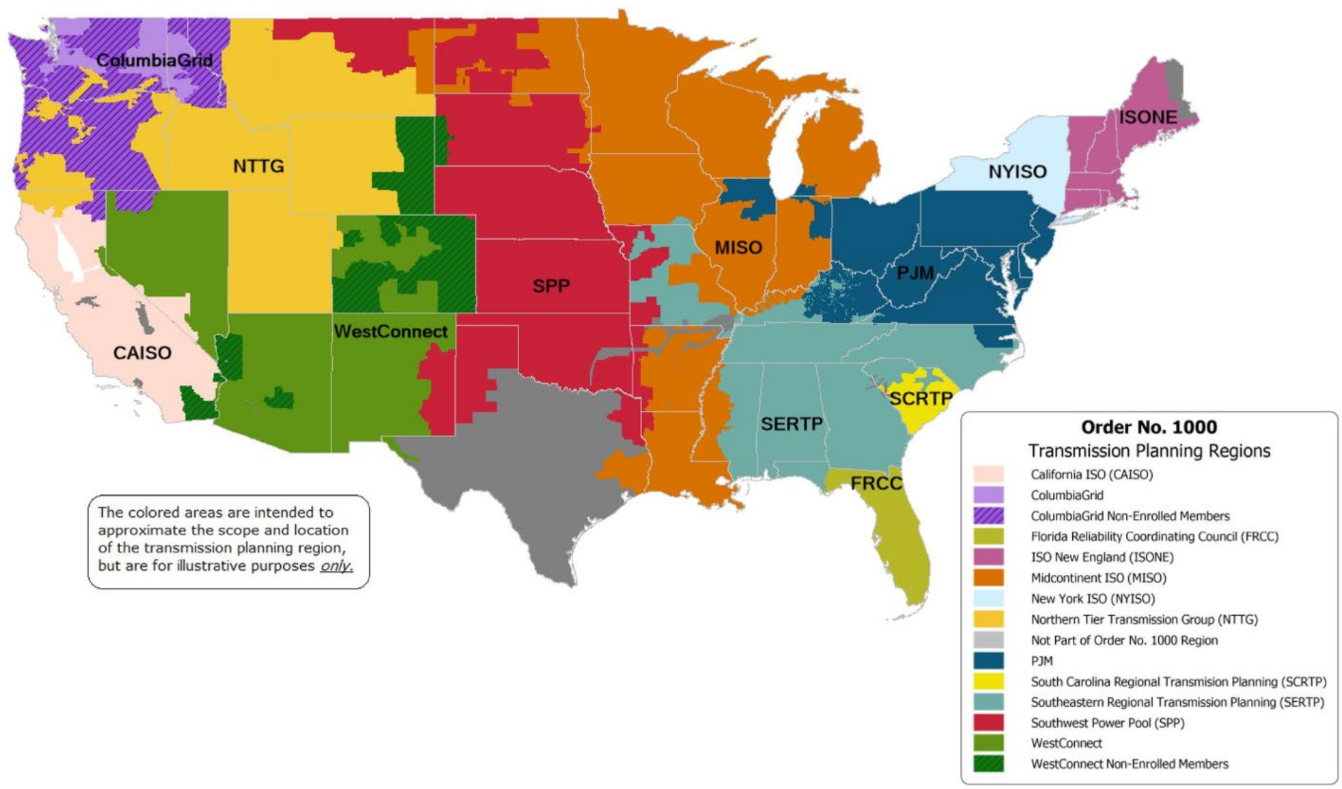
**Less Than 18,000 Miles to Be Put in Service Over the Next Decade**

Less than 18,000 miles (on a base system of 180,000) are currently planned to be put in service between 2021 to 2031. In contrast, some studies suggest that the current system needs to double or triple in size to accommodate clean energy goals.

Depending on the region, transmission planning may include integrated utilities, wires only utilities, regional transmission organizations (RTOs)/independent system operators (ISOs), and regional and subregional reliability coordinators. Regulatory oversight varies as well. While transmission planning is regulated by FERC for the aforementioned entities, public power, municipal, and cooperative utilities are not subject to FERC's jurisdiction. While transmission facilities can span states and service territories, the planning for them is balkanized and dependent on voluntary cooperation across different organizations, including stakeholder forums, such as regional reliability organizations, subregional forums, or among joint owners (see, e.g., Figure 2.1).[14]

The transmission plans developed as a result of these studies articulate the upgrades to transmission lines and substations necessary to ensure the ongoing reliability of the electric grid.

Figure 2.1 – Transmission Planning Regions Under FERC Order 1000[15]




[14] See, e.g., http://www.westconnect.com/

[15] https://www.ferc.gov/sites/default/files/industries/electric/indus-act/trans-plan/trans-plan-map.pdf

### FERC Order 1000

FERC Order 1000, issued in 2011, established the requirements for transmission planning for all of FERC's jurisdictional entities. Transmission planning processes must comply with its requirements. Order 1000 provided specific requirements for the following:

- Regional transmission planning – Order 1000 requires participation in a regional planning process. The plan must take into account the issues described above, as well as others pertinent to the specific geography or topology. Under Order 1000, there are three primary types of projects:
  - **Economic:** Improvements that reduce congestion (limits on the amount of energy that can be transmitted through a given part of the system). Often relief from these constraints can reduce power costs, as increased supply can be introduced to a wider part of the system (more supply, lower cost). These projects typically require a cost-benefit analysis.
  - **Reliability:** Improvements that alleviate constraints or change flows in the system that had experienced or were expected to experience outages, transmission line overloading, short circuits, or other sources of potential system failure. NERC sets the criteria for reliability and the system is assessed and planned against those criteria.
  - **Policy-Driven:** Improvements that are required by the implementation of state or federal policy requirements, such as RPS, clean energy standards, or other mandated resources.
- Consideration of transmission needs driven by public policy requirements – One of the three types of projects identified above. These projects go beyond reliability-driven needs to facilitate policy mandates (e.g., RPS).
- Non-incumbent transmission development – Each region needed to develop a manner by which non-incumbent transmission developers could participate in competitive solicitations for transmission projects selected in a regional plan, subject to certain exceptions, such as upgrades.
- Interregional transmission coordination – Regions needed to define how they would work with neighboring regions to develop infrastructure across seams that may more efficiently or cost effectively address regional needs.
- Cost allocation for transmission facilities selected in a regional transmission plan – Each region needed to develop methodologies complying with certain principles[16] by which costs for the projects identified in the transmission plan would be allocated to entities in the region. The project types identified above drive cost allocation decisions.

Order 1000 mandates that costs must be "roughly commensurate" with a project's benefits. However, because the transmission system is a network, a project may benefit multiple stakeholders, making allocation of those costs difficult.

[16] These principles are: (i) costs allocated roughly commensurate with benefits; (ii) no involuntary allocation of costs to non-beneficiaries; (iii) a benefit-to-cost threshold ratio; (iv) allocation to be solely within transmission planning region(s) unless those outside voluntarily assume costs; (v) transparent method for determining benefits and identifying beneficiaries; and (vi) different cost allocation methods may be used for different types of transmission facilities (Morrison Foerster Client Alert, "FERC Order No. 1000, Final Rule on Transmission Planning and Cost Allocation: Major Changes Ahead," July 25, 2011). More discussion in the Cost Allocation section of this paper.

While significant progress has been made under Order 1000 in defining regional planning and cost allocation, interregional planning processes remain in their infancy. Planning remains a patchwork process rather than a master planning exercise. There is today no mechanism to enable the type of national planning many believe is needed to facilitate integration of large amounts of renewables across regions and interconnections.

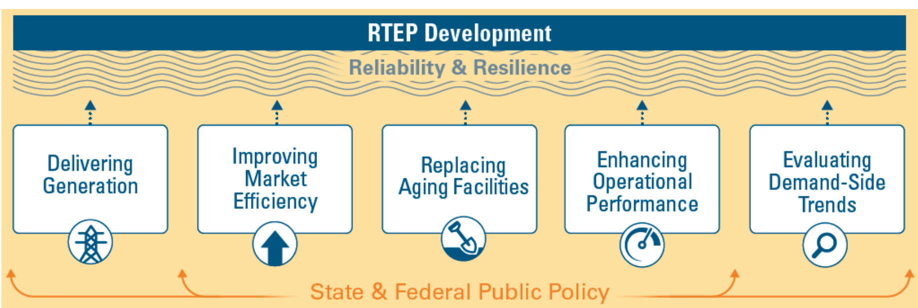
Order 1000 is the basis for the planning processes that exist in the United States today. As the industry recognized the need for additional transmission infrastructure in the early 2000s, transmission planning and cost allocation were identified as key issues. FERC's initial attempt to address these questions came in Order 890 in 2007.[17] It was followed by the issuance of Order 1000 in 2011. The following section provides an example of how these processes have been implemented in PJM and illustrates the complexity of regional planning.

### Planning in RTOs: PJM Example

Planning approaches vary among RTOs. Here we look at the processes of the PJM Interconnection, which covers much of the Mid-Atlantic region, as an example.

Planning in PJM begins with the regional transmission expansion plan (RTEP),[18] which assesses anticipated system needs over the next 15 years. This long-term horizon "gives the developers who take on these projects time to marshal the necessary resources and gain state and local approvals to build the infrastructure."[19]

Figure 2.2 – PJM RTEP System Enhancement Drivers[20]




The RTEP contemplates several system expansion drivers, as noted at left. The RTEP looks across the region as a whole rather than at states or individual transmission owner territories.

New transmission projects—whether identified by PJM or by transmission owners as "supplemental projects"[21]—are built to serve one or more purposes: increase power-flow capability, provide voltage support, improve generating unit stability, or ensure safe transmission line operation.

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[17] See Order 1000, at pp. 18-29. In early 2007, FERC issued Order 890. In promulgating that order, FERC pointed to the lack of clear criteria regarding the transmission provider's planning obligation; the absence of a requirement that the overall transmission planning process be open to customers, competitors, and state commissions; and the absence of a requirement that key assumptions and data underlying transmission plans be made available to customers. After Order 890 compliance filings and technical conferences in fall 2009, FERC saw the remaining deficiencies in transmission planning and cost allocation processes and issued proposed Order 1000 in June 2010. Order 1000 was initially promulgated in July 2011. Rule clarifications were issued in May 2012 (Order 1000-A) (see FERC Docket No. RM10-23-001) and October 2012 (Order 1000-B) (see Docket No. RM10-23-002).
[18] See https://www.pjm.com/library/reports-notices/rtep-documents.aspx
[19] PJM, The Benefits of the PJM Transmission System (Apr. 16, 2019), at p. 8
[20] PJM, Regional Transmission Expansion Planning: Planning the Future of the Grid, Today (Oct. 2019) (RTEP Summary); PJM Training Materials, System Planning: Introduction (May 2021)
[21] Further defined below

Transmission projects considered under the RTEP process fall into three categories: baseline projects, network projects, and supplemental projects (see Figure 2.3). The planning process produces a transmission solution that will meet the need and is the most reliable and least-cost option. The solution considers generation, distributed energy resources, or other resources that exist or are in the interconnection queue.[22] These considerations are dynamic and require that the planning process (and ultimately the grid) be flexible to accommodate the resources the market connects to the system, making the transmission planning process both complex and iterative. The process differs by project type; however, the project types identified under Order 1000 are represented (reliability, economic, public policy), as shown below:

Figure 2.3 – PJM RTEP Transmission Project Types

| Type | Description/Driver | Planning Process |
|---|---|---|
| Baseline | ■ Addresses **reliability** criteria violations.<br>■ Identifies **market efficiency/ economic** (congestion in energy flows) improvements.<br>■ Determines **public policy** needs (e.g., interconnecting renewable generation mandated by federal or state policy). | ■ After PJM identifies a baseline transmission need, it may open a competitive proposal window, depending on the required in-service date, voltage level, and scope of likely projects.<br>■ Throughout each RTEP window, developers can submit project proposals to address needs. When a window closes, PJM evaluates each proposal to determine if any meet its project requirements.<br>■ If so, PJM then recommends a proposal to the PJM Board of Managers. Once the Board approves a proposal, the designated developer becomes responsible for project construction, ownership, operation, maintenance, and financing. |
| Network | ■ Ensures new generation and merchant transmission projects interconnect reliably to the grid as submitted through PJM's interconnection queue. | ■ PJM identifies the affected parties who bear the responsibility for network system projects that enable the interconnection of new generation and other new transmission services. |

[22] See Interconnection section of this paper.

| Type | Description/Driver | Planning Process |
|---|---|---|
| Supplemental | ■ Identified by PJM transmission owners to address their own local transmission reliability needs. These projects direct repairs or improvements to local transmission lines and equipment, address local operational issues, customer load growth, and resilience.<br>■ Even though the owner develops these projects, PJM reviews them (i) to evaluate their impact on the regional transmission system, (ii) to coordinate necessary construction outages, and (iii) to implement necessary changes in PJM's models and system operations.[23] | ■ Better described as owner-driven projects, supplemental projects employ a different process than baseline projects.<br>■ Transmission owners develop these projects themselves to address local reliability needs and are responsible for building them.[24]<br>■ These projects are integrated into the RTEP, but the PJM Board does not approve individual supplemental projects.[25] |

These planning steps yield a five-year look-ahead base case. The planning cycle runs 24 months from initial analysis to final recommended transmission project recommendations. A new 24-month cycle is initiated every 18 months. Note that this cycle ends the planning process—solicitation of proposals and actual construction occur after this.

In summary, the planning process is complex with multiple inputs, uncertainties, and stakeholders. As one study observed, "traditional planning approaches are no longer adequate to achieve least-cost outcomes in light of challenges such as plant retirements, renewable generation integration, and increasingly stringent environmental regulations that lead to significantly more complex and less predictable power systems."[26]

### Conflicts Between State and Regional/Federal Interests

Conflicts can arise if regional or multi-state grid enhancements (as identified by a regional/RTO process) are seen by a state's regulators as offering minimal benefits to its ratepayers. As the costs associated with regional or multi-state transmission are typically socialized, parties may object if they perceive their benefits received do not match their "costs incurred." According to a recent national study: "It is harder to gain approvals in situations where transmission enhancements might provide net social economic benefits (e.g., by opening up a congested electric corridor) or support for facilities that are needed for meeting state policy objectives. Even where regional transmission planning processes identify that a particular new multi-state line would produce economic benefits for the region, regulators in a state crossed by that line might find insufficient in-state economic benefits to overcome the environmental and other burdens of hosting the proposed line."[27] While reliability-driven projects may face less opposition, the challenge of cost causer versus beneficiary plagues transmission planning efforts across the country.

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[23] PJM, The Benefits of the PJM Transmission System (Apr. 16, 2019)
[24] RTEP Summary, at p. 3
[25] PJM Manual 14B: PJM Region Transmission Planning Process Revision 48 (effective Oct. 1, 2020), Section 1.4.1.7, at pp. 25-26
[26] Eastern Interconnection States' Planning Council, Co-optimization of Transmission and Other Supply Resources (Sept. 2013), cited in WIRES, Well-Planned Electric Transmission Saves Customer Costs (June 2016), prepared by The Brattle Group
[27] National Academies of Sciences, Engineering, and Medicine, The Future of Electric Power in the United States (2021) (NAS Report), at p. 121

Support and interest in wide-scale, interconnection-wide planning has waned in the Eastern and Western Interconnections. The Eastern Interconnection Planning Collaborative conducted several studies in the early 2010s examining needs across the planning regions, but little activity has occurred in recent years.[28]

***While the need to move energy from remote resources to load centers across wider geographic areas has increased, collaborative efforts to facilitate that have lost support and have had little impact.***

[28] NAS Report, at p. 123

## COST ALLOCATION

### Key Takeaways

- The general principle of cost allocation is that the cost causer or the beneficiary should pay for transmission upgrades in proportion to which they either cause or benefit from the upgrades.
- Assessing who benefits is extremely challenging, especially when transmission lines cross jurisdictional (federal, state, local) boundaries. Further, these different constituencies complicate cost allocation.
- The dynamic nature of the networked transmission grid makes assessing costs and benefits over time difficult.

### Investment Characteristics of Transmission

Transmission is a long-lived, regulated, rate of return asset for utilities,[29] and transmission infrastructure is typically depreciated over a period of 30 years or more. Transmission owners recover through rates their initial capital investment (and any subsequent investments) and a fair return, as well as recovery of operating, maintenance, and administrative costs associated with operating the assets. For transmission owners, the ability to place assets into rate base where they earn a stable and predictable rate of return incentivizes investment.

The typical transmission portion of a customer's bill is small relative to the total delivered cost of electricity. In 2020, according to the Edison Electric Institute (EEI), the cost for transmission was projected to contribute only 13% of total customer bills, compared to the generation and distribution components, which represent 56% and 30%, respectively.[30]

### Patchwork of Regulators, Jurisdictions, and Policies

Overlapping and sometimes conflicting patchworks of regulators and jurisdictions complicate cost allocation for transmission. Ultimately, transmission costs (like all other costs of electric service) must be borne by end-use retail electric customers. In the federal-state shared jurisdiction in the United States, customers are billed by service providers under a state's public utility commission-approved tariff. In theory, state regulators, being accountable politically to their citizens, serve as protectors of consumer interests. However, FERC establishes rates and approves cost allocation mechanisms proposed by transmission owners and operators. FERC is charged with ensuring that rates for transmission must be "just and reasonable" and not "unduly discriminatory."

Conflicts arise as federal policy seeks to ensure broader regional or national grid performance and economic optimization, while state regulators are principally concerned with local, parochial interests. Another complication arises when transmission systems span state lines and multiple state regulators take a narrower view of customer interests, focused on their particular local jurisdictions. For reliability projects, policymakers may be reluctant to pay for projects that benefit other states. For regional public policy projects (e.g., renewables integration or other environmentally driven transmission), states that do

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[29] There are, however, merchant transmission projects that recover costs through market-based contracts and fees, but those projects are de minimis in context of all installed transmission in the United States.
[30] EEI, Statistical Yearbook of the Electric Power Industry (2018 and 2019 data), published Aug. 2020 (at p. xix)

not have those policies may be reluctant to pay for transmission required by states that do, especially if those projects support out-of-state projects with few direct local economic benefits.[31] Importantly, the same state regulators that assess the allocation of transmission costs have a key role in the siting and permitting of projects in their states.

The bottom line is that allocating costs across competing constituencies and jurisdictions can be extremely challenging. It creates hurdles to developing and implementing new transmission projects and contributes to the piecemeal development of the grid.

### Principles of Cost Allocation: Cost Causer or Beneficiary Pays

Cost allocation methodologies vary somewhat by project type and by region, but the general principle is that the “cost causer” or beneficiary should pay for incremental upgrades to the transmission system in proportion to which they either cause the cost (e.g., additional infrastructure needed to connect new generation to the system) or benefit from transmission upgrades (e.g., by realizing lower cost of energy enabled by improved flows on the system). Order 1000 requires that costs should be allocated in a way that is roughly commensurate with estimated benefits.

This contrasts with cost socialization, which is still used for projects above cost or voltage thresholds defined by the regions, where all transmission users cover total costs on a pro rata basis. Order 1000 goes further, noting that a planning process may consider benefits, including “the extent to which transmission facilities, individually or in the aggregate, provide for maintaining reliability and sharing reserves, production cost savings and congestion relief, and/or meeting Public Policy Requirements [such as RPS].”[32]

Benefits, however, can be hard to identify, quantify, and link to costs. In small, contiguous areas with a largely identifiable customer base and a defined local transmission need, the relationship between cost and causation is straightforward to quantify. But in a larger, broader network, benefits may be diffuse and indirect. Increasing the ability to import power in one area may have ancillary benefits of lowering energy costs outside of that particular area on the grid. Or, increasing transmission capacity in one part of the grid may result in increased capacity in another part of the grid, much as an interlinked highway system may have congestion relieved in different locations by adding or expanding a beltway. This is especially true for large regional or interregional projects.[33] And these values can change over time as more changes are made to the grid.

The nature of the grid is dynamic; costs and benefits change as topology and generation resources shift. These complicate assignment of costs to various stakeholders. The inability to agree on cost allocation, particularly for large interregional projects, will hamper integration of large amounts of renewable generation.

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[31] See The Brattle Group, “Transmission Cost Allocation: Principles, Methodologies, and Recommendations” (Nov. 16, 2020), prepared for the Organization of MISO States Cost Allocation Principles Committee Meeting, available at https://brattlefiles.blob.core.windows.net/files/20508_transmission_cost_allocation_-_principles_methodologies_and_recommendations.pdf

[32] FERC Order 1000, at p. 421

[33] From WIRES Report:
**Challenges in identifying and allocating benefits:** However, effective implementation of these principles has proven challenging. As one analysis has noted, “[I]dentifying who benefits from transmission services and by how much is an analytically complex task in power systems planning and operation. The expansion of interregional transmission capacity and subsequent exchange of energy produce differentiated distributional effects in each region, independently of whether a new tie line creates an aggregated net benefit. These distributional effects create winners and losers at each side of the transmission tie lines, which may create opposition to the projects or simply threaten their sustainability, as each region needs to balance their own benefits and costs” (Prada & Ilic, at pp. 4–5). Further, the benefits of, for example, congestion relief may result in cost improvements or have positive resilience impacts that are difficult to disentangle and allocate between regions and beneficiaries.

## TRANSMISSION INTERCONNECTION QUEUES

### Key Takeaways

- The current process for interconnecting generation to the transmission system was designed to connect a modest number of large central station generators to the grid, not a much larger number of smaller wind and solar projects.
- Reliance on participant funding and a generator-by-generator approach to assess and enhance the grid is causing delays in interconnection queues across the country.
- Delays in the interconnection process and the high cost of transmission upgrades are causing new generation projects to drop out of interconnection queues.

### Interconnection Policies and Processes

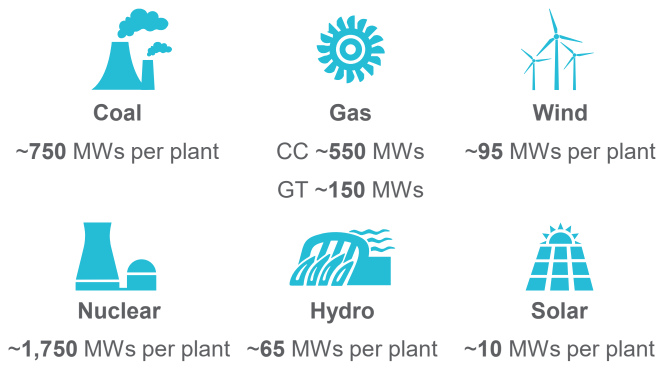
When a utility or developer proposes to add a generation resource to the electric system, the operator of the grid must consider the impacts that resource will have on the transmission system. Interconnection rules are therefore designed to balance two objectives:

- Providing a transparent and efficient means to interconnect the resource
- Maintaining the safety, reliability, and power quality of the electric power system

FERC establishes policy and rules governing interconnection of generation to transmission facilities. In RTO regions, those policies are administered by the RTOs. In non-RTO regions, FERC directly oversees transmission-level interconnections.

The generation interconnection processes in most regions were designed to accommodate large (multiple gigawatts in capacity), conventional power generation sources with highly predictable operating characteristics, located close to where that power was consumed. Those types of large generation interconnections often require significant transmission upgrades to be integrated into the transmission system, but those requests are infrequent and manageable to study. They are studied one at a time, in the order in which they enter the queue. The costs to interconnect, typically borne by the generator, are assessed through this process.

Illustrative Scale of Power Generators by Type[34]




Today, as large "central station" sources of generation are replaced with smaller, more numerous, and more dispersed renewable resources, transmission interconnection queues have struggled to keep up with the sheer number of new requests. The processes that worked well to study the interconnection of large nuclear or natural gas plants get bogged down when assessing the large volume of small requests coming in today.

***Across CAISO, ISO-NE, NYISO, and PJM, generation projects constructed in 2010–2020 spent 3.5 years in interconnection queues before being built, increasing from 1.9 years in the prior decade.***

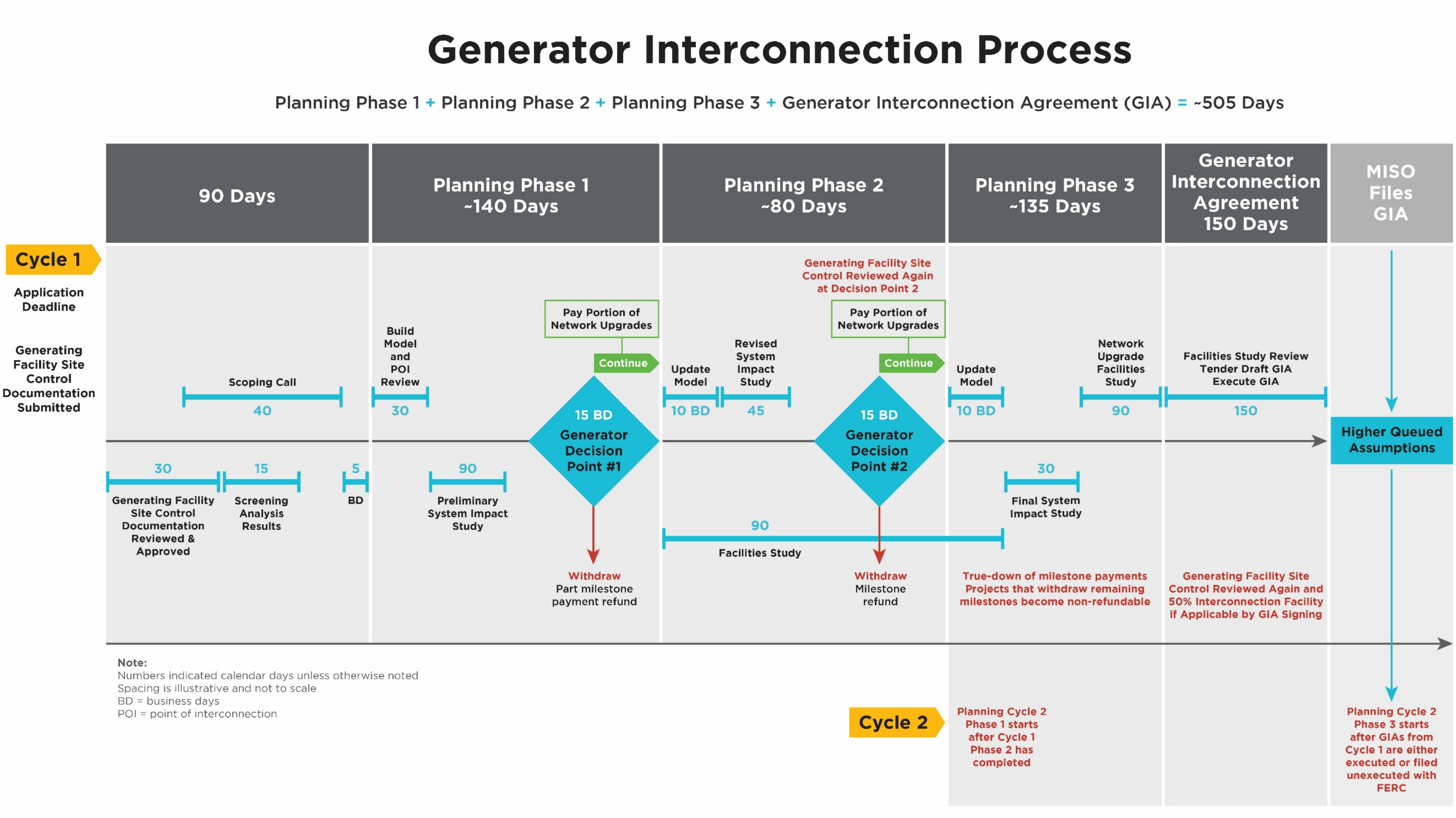
The interconnection processes often favor "participant funding," assessing network upgrades attributable to individual projects. This does not provide a mechanism for assessing groups or clusters of projects near particularly rich wind or solar resources, which may deliver broader system benefits and lower production costs across the region, and it leads to incremental, piecemeal solutions that fail to address the greater needs of the transmission system.

Because the cost of interconnection is not known until at least some studies by the RTO or transmission owner are completed, developers may not be able to assess the feasibility of their projects until well into the interconnection studies. Projects are withdrawing from queues when unexpectedly high costs are assessed later in the study process. This further complicates the work of the planning regions, too, which must then reshuffle the projects in the queue and conduct new studies as projects are withdrawn and new projects added. This churn further exacerbates delays, uncertainties, and costs associated with interconnecting to the grid.

***Only 24% of projects in the queues reached commercial operations in CAISO, ISO-NE, MISO, NYISO, and PJM combined. Completion rates are even lower for wind (19%) and solar (16%).***

[34] Source: S&P Market Intelligence; ScottMadden analysis

Figure 4.1 – Illustrative Interconnection Queue Process Flow Diagram (from MISO)[35]




[35] Source: Midcontinent ISO, at https://www.misoenergy.org/planning/generator-interconnection/ and https://cdn.misoenergy.org/GI%20Process%20Flow%20Diagram106549.pdf

### Snapshot of an Interconnection Queue: MISO Example

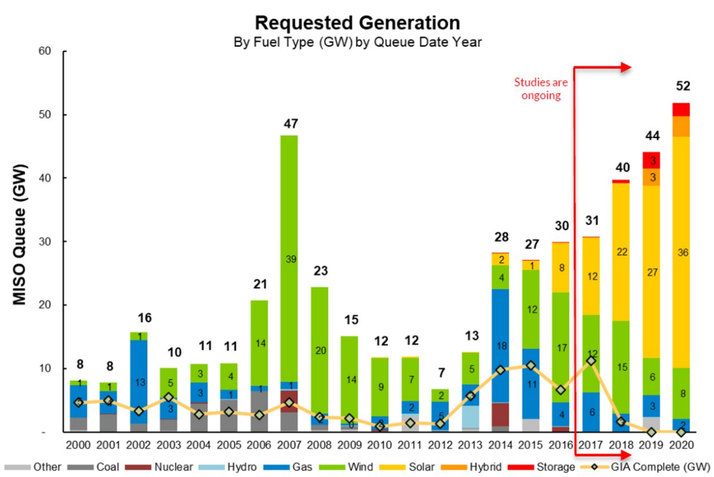
In August 2020, MISO announced the largest number of new requests for generation interconnection in its history, with 353 project applications representing approximately 52 GWs of new generation capacity. Sixty-nine percent, or 36 GWs, is solar. As of MISO's latest update in April 2021,[36] the current active queue far outpaces the 2020 record with 557 projects representing 83.3 GWs of capacity, 65% of which was solar.

Figure 4.2 – MISO Interconnection Queue (2017 vs. 2020–21)[37]

| | 2017 | 2020 | 2021 |
|---|---|---|---|
| Number of projects in the queue | 163 | 353 | 557 |
| Total MWs of capacity | 31,000 | 52,000 | 83,300 |
| Solar component in MWs (%) | 12,000 (39%) | 36,000 (69%) | 54,000 (65%) |

In 2017, approximately 5,000 MWs of new renewable energy projects had been approved to interconnect to the MISO grid,[38] but when MISO's studies indicated that upgrades worth hundreds of millions of dollars would be needed to integrate those new resources, the capacity in the queue dropped to 1,500 MWs. Only two projects, representing 250 MWs, ultimately moved forward in the process.[39] A separate analysis found that, from 2016 through October 15, 2020, developers withdrew 278 wind, solar, and battery storage or hybrid solar-storage projects from the queue. These 278 clean energy projects had reached advanced stages of the interconnection process before withdrawing and represented nearly 35,000 MWs of capacity.[40]

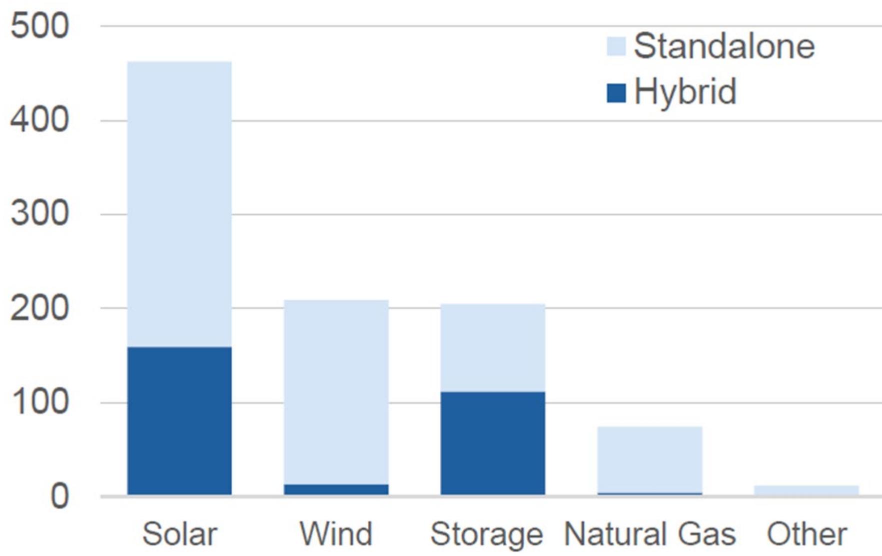
Figure 4.3 – Historical Trend in the MISO Interconnection Queue[41]




[36] MISO's latest Generation Interconnection Queue web update (dated Apr. 1, 2021), available at https://cdn.misoenergy.org/GIQ Web Overview272899.pdf
[37] MISO, Generator Interconnection: Overview (updated June 7, 2021), available at https://cdn.misoenergy.org/GIQ%20Web%20Overview272899.pdf
[38] Approval evidenced by an executed Generator Interconnection Agreement (GIA) filed with FERC.
[39] https://energynews.us/2020/01/10/as-bottleneck-stymies-projects-midwest-groups-call-for-transmission-reforms/
[40] Sustainable FERC, available at https://sustainableferc.org/wp-content/uploads/2021/01/SFP-MISO-Queue-Map-Update-2-pager-11-9-20.pdf
[41] MISO, Generator Interconnection: Overview (updated June 7, 2021), available at https://cdn.misoenergy.org/GIQ%20Web%20Overview272899.pdf

Significant capacity remains in interconnection queues nationwide. According to one national laboratory, more than 755 GWs of generator capacity and 200 GWs of storage is currently (as of year-end 2020) seeking interconnection. Most (~680 GWs) proposed generation is zero carbon. Hybrids—installations that include two or more different generation types (or storage)—now comprise a large and increasing share of proposed projects (see Fig. 4.4 below).

Figure 4.4 – Capacity in U.S. Interconnection Queues (GWs) as of Year-End 2020[42]




FERC and the RTOs have acknowledged the challenges with interconnecting these new types of resources and have attempted to address them through process changes. MISO has made some reforms that have helped to reduce churn and the number of backlogged projects. MISO's Interconnection Process Working Group is developing plans to reduce the total timeline for the generation interconnect process from 505 calendar days to 373 calendar days, a savings of 132 days, but still more than a year.

Continued and rapidly growing renewable development is likely in response to ambitious federal, state, and utility net-zero and clean energy standards. Interconnection queues for these new generation resources will continue to be crowded with proposed projects. Queue reform has begun to address delays in evaluating these projects as well as withdrawal of projects from queues. It is unclear, however, whether reforms will be sufficient to address increasing volumes of proposed projects to meet near-term clean energy milestones.

[42] Lawrence Berkeley National Lab, Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection as of the End of 2020 (May 2021). Data for 7 ISOs and 35 non-ISO utilities. Hybrid facilities are facilities that have multiple, co-located generator types, including storage.

## RATEMAKING AND INCENTIVES

### Key Takeaways

- FERC sets the return on equity (ROE) for transmission investments. ROEs help determine the attractiveness of these investments.
- FERC Order 679 established incentives to encourage investment in transmission, including ROE adders. Those incentives helped increase investment in transmission starting in the mid-2000s.
- It is unclear whether these incentives continue to be effective, and FERC is revisiting policy in this area.
- Incentives alone cannot address the other headwinds facing transmission development.

### Ratemaking for Transmission

Because transmission infrastructure is a long-term commitment, often serving the public for 50 years or more, investors require adequate and stable returns over the life of these assets. The stability and predictability of authorized returns are important to investors (including utility and independent transmission shareholders), who must commit capital to long-lived assets with multi-year development cycles.[43]

Because transmission is deemed to be interstate commerce, federal authority is primary. FERC is responsible for setting the rates of return for investments in transmission by establishing ROEs that transmission owners may earn on their assets.

While state public utility commissions are not involved in establishing returns or incentives for transmission investments, they do have jurisdiction over the rates that end-use customers ultimately pay. This includes the recovery of transmission revenues in retail rates. As such, the states and other transmission customers have a keen interest in the returns granted to transmission owners because their retail constituencies pay them. These stakeholders often voice objections to proposed projects that do not align with state or local interests.

**Ratemaking Basics***

- FERC transmission regulation is “cost of service” regulation. The regulator determines the cost of service that must be collected in rates from customers so the utility can recover its costs and a reasonable return on and of investment.
- This regulatory arrangement is in exchange for a utility’s obligation to serve customers with its facilities.
- The basic ratemaking formula is:
  Rate base
  x Allowed rate of return
  = Required return
  + Operating expenses
  = Revenue requirement
- The rate base is the net amount of investment, funded by investors, in utility plant and other assets devoted to the rendering of utility services.
- The revenue requirement is allocated among customers based upon the cost driver—e.g., peak usage (MW) and/or total usage (MWh).
- Transmission rates are often determined by a FERC-approved formulaic methodology (a “formula rate”), used to annually compute transmission revenue requirements and/or transmission service rates based on either historical or projected data for the utility’s transmission-related assets, liabilities, equity, revenue, and expenses.

* Adapted from “Tariff Development I: The Basic Ratemaking Process,” Briefing for the NARUC/INE Partnership, available at https://pubs.naruc.org/pub.cfm?id=538E730E-2354-D714-51A6-5B621A9534CB

[43] Suppliers of equity capital for investor-owned electric companies include individual investors and institutional owners, such as pension funds, government retirement funds, mutual funds, insurance companies, and endowments.

In response to decades of underinvestment in the transmission system, FERC issued Order 679 in 2006. The order was intended to promote investment in transmission infrastructure, thereby promoting reliability, lowering costs to consumers, and reducing transmission congestion.

As mentioned throughout this paper, transmission investors assume numerous risks and challenges, including long lead times, significant development opposition from affected stakeholders, and extensive state and federal permitting and siting processes. Recognizing these risks,[44] Order 679 established numerous incentives to encourage investment in transmission, including incentive ROEs (ROE adders above a standard calculation of equity return) and full recovery of prudently incurred construction work in process (CWIP),[45] pre-construction costs, and costs of abandoned transmission facilities. The latter three incentives were intended to provide transmission developers some measure of comfort that their costs would be recovered if projects (through no fault of their own) were delayed or ultimately denied.

Those incentives achieved many of their desired effects, as investments in transmission increased markedly in the mid-2000s, and the trend continued into the middle of the last decade. The ROEs for transmission were attractive in their own right and relative to other investments that utilities might make. In addition, formulaic ratemaking, which enabled transmission owners to set rates without going through a rate proceeding at FERC, facilitated investment in the system.

More recently, however, due to a combination of headwinds, investments in transmission have lagged their prior pace. These headwinds include local resistance to large infrastructure projects, pushback from some consumer advocates, environmental challenges, and inconsistent incentive awards to developers. And returns on equity calculations were challenged in some regions. Though the number of projects and the dollars allocated to transmission projects has continued to increase, the total miles of transmission added peaked in 2016. Over the last five years the pace of investment has slowed, and the scope and scale of transmission projects have decreased.

Figure 5.1 – Miles of Transmission Line Added Since 2013[46]


This has led to the reconsideration of transmission incentives and whether they are effective at continuing to attract capital to the sector. On March 20, 2020, FERC issued a notice of proposed rulemaking, proposing to revise its existing electric transmission incentives policy to enhance opportunities for utilities to qualify for and receive transmission incentives, including additional ROE adders in transmission rates,

44 For all of the reasons that transmission development is challenging, it is discussed elsewhere in this paper.
45 CWIP is a capital expenditure. This allows earning a return on investment before construction is completed and the facility goes into service.
46 S&P Global Market Intelligence; ScottMadden analysis

for transmission projects that ensure reliability of the grid or reduce the cost of delivered power by relieving transmission congestion.

FERC's commissioner (now chairman) Richard Glick has also expressed interest in FERC re-examining transmission incentives, specifically adders for participating in an RTO.[47] Commissioner Glick questioned whether ROE adders are necessary in light of reforms under Order 1000 and the lower cost of capital since their introduction.

Recently approved ROEs for transmission range from 9.85% to 11.20%, which compares favorably with the median approved electric distribution ROE in 2020 of 9.45%. For comparison, the 12-month return on the S&P is 41.94% (as of 4/30/21).

**Recently Concluded FERC Transmission Proceedings Featuring Contested ROEs (as of July 2020)**

| Date Concluded | Company | Prior Base ROE (%) | New Base ROE (%) |
|---|---|---|---|
| May 2019 | American Electric Power (in PJM) | 10.99 | 9.85 |
| June 2019 | American Electric Power (in SPP) | 10.70 | 10.00 |
| June 2019 | Southern Co. | 11.25 | 10.60 |
| October 2019 | Gulf Power Co. | 10.25 | 10.25 |
| November 2019 | Oklahoma Gas & Electric Co. | 10.60 | 10.00 |
| December 2019 | Southern California Edison Co. | 9.30 | 11.20[1] |
| December 2019 | PECO Energy Co. | NA | 9.85 |
| March 2020 | San Diego Gas & Electric Co. | 9.55 | 10.10 |
| May 2020 | Midcontinent ISO | 9.88 | 10.02 |
| May 2020 | Cheyenne Light, Fuel and Power Co. | 10.60 | 9.90 |

NA = not applicable or not applicable
[1]Represents "all-in" ROE inclusive of 50 basis point California ISO adder and project-specific adders of 0.75% to 1.25% authorized by FERC.
Sources: FERC; Regulatory Research Associates; S&P Global Market Intelligence

The combination of Order 679 incentives and formulaic ratemaking drove significant investment in transmission through the 2000s and 2010s. As transmission investment competes for capital with other investments, reducing ROEs or incentives earned will reduce its attractiveness both to utilities and to non-utility developers. Depending upon the rulings FERC makes on these topics, the case for transmission investment may be bolstered or may face additional headwinds. While FERC's incentives policy did stimulate investment in transmission in the 2000s and 2010s, incentives alone will not address the various barriers facing transmission development today.

[47] "Commissioner Richard Glick Dissent in Part Regarding Approval of RTO Participation Adder," (Dec. 31, 2020), at https://www.ferc.gov/news-events/news/commissioner-richard-glick-dissent-part-regarding-approval-rto-participation-adder

## SITING AND PERMITTING

### Key Takeaways

- Siting and permitting for transmission development include a complex system of stakeholders and administrative processes.
- States play a critical role in reviewing transmission plans, project development, and permitting. Multi-state projects increase these reviews dramatically.
- Multiple, tiered approvals among federal, state, and local stakeholders with different mandates and authorities add both time and uncertainty to siting and permitting.
- The Energy Policy Act of 2005 (EPAct 2005) established a potential pathway to give the federal government backstop siting authority; however, that authority has been challenged in the courts and effectively neutralized.
- While certain clean energy advocates support building transmission to connect renewables, specific transmission projects often face significant opposition due to local environmental impacts.

### Current Landscape for Siting and Permitting of Transmission

Transmission siting includes a complex system of stakeholders and administrative processes, each with its own interests and rules. Siting—the approval of the location and routing of transmission facilities—involves "balancing disturbance to human, cultural and natural resources with a community's need for reliable electricity."[48] For a transmission project to be developed, it may need to acquire the necessary siting permits from a set of states, localities, and federal authorities to construct the facility.

State laws and regulations primarily govern the approval process for siting and construction, though in some states, city and county authorities may also be involved. Securing authorization for a transmission project hinges on the determination of need and public interest, and that determination (referred to as a "certificate of public convenience and necessity") rests with the state's public utility commissions. States generally conduct a siting process to inform their public interest determinations, which often include public hearings and economic and environmental reviews of proposed projects.[49] For projects on non-federal lands, states also have the authority to use eminent domain in cases where private landowners do not approve of a transmission project.

> Depending on the project, the transmission developer may need to gain siting approval from the state, county, and federal land management agencies. Other authorizations may include permits under the Clean Water Act, the Rivers and Harbors Act, and the Bald and Golden Eagle Protection Act. Consultation or review under the Endangered Species Act, the National Historic Preservation Act, and the Federal Aviation Administration Act may also be required.
>
> – FERC Staff Report to Congress on Barriers and Opportunities for High Voltage Transmission

In addition to state approvals, transmission projects may also require various authorizations and reviews at the federal level. Projects crossing federal lands are required to obtain right-of-way permits from the relevant land management agencies which often require different information from that needed by the state.[50] In determining whether or not to issue a permit, those agencies must also comply with the

[48] https://www.aeptransmission.com/property-owners/line-siting.php
[49] FERC Staff Report to Congress on Barriers and Opportunities for High Voltage Transmission (June 2020)
[50] The five major land management agencies, listed from most to least lands managed, include the U.S. Bureau of Land Management, U.S. Forest Service, U.S. Fish and Wildlife Service, U.S. National Park Service, and U.S. Department of Defense.

National Environmental Policy Act, which prescribes a process for assessing potential environmental impacts. And, further complicating siting and permitting for transmission, litigation may happen at any stage of the approval process. Further, siting permits and environmental reviews often have a limited shelf life and thus may lapse if other complications cause delays. In other cases, approval timelines for certain sections of a right-of-way may exceed those for others because of the differing siting authorities.[51]

### Local Opposition: State and Local NIMBY Concerns

Some intervenors in the processes to site and permit transmission infrastructure are not satisfied with any project for any reason. Objections range from aesthetic or environmental impacts to lack of local benefits to hostility to eminent domain.

The language in state statutes governing interstate transmission siting varies throughout the country. Statutes in some states provide concrete direction for working with utilities and other states, while statutes in other states may prevent interstate coordination or remain silent on the topic of siting transmission.[52] Recent evidence suggests that these challenges are as daunting today as they were 20 years ago, if not more so.

***Since 2013, more than 18,000 miles of transmission projects have been cancelled. Long distance projects (>100 miles) made up three quarters of the total cancelled line miles. The average time from start of development to cancellation was more than six years.***

There is a compounding effect with larger, longer proposed lines, as increasing numbers of state governmental, regulatory authorities, and individual landowners become involved. In recent years, some large projects aimed at moving large-scale renewable resources between regions have been slowed or stopped due to state or local action (see callout on next page).

> ***"Siting within a single state can be a difficult challenge: concerns about land use impacts, property values, technical considerations, jurisdiction, and the appropriate allocation of costs and benefits can delay or derail a proposed project. On an interstate basis, these issues are multiplied by the number of states the line traverses."***
>
> ***– The National Council on Electricity Policy***

### Federal Backstop Siting Authority

Unlike FERC's siting and eminent domain authority for natural gas pipelines, which was first established in the Natural Gas Act of 1938 and exercised many times since then, FERC's backstop siting authority is much newer, and it has never been exercised for power transmission.

As outlined in EPAct 2005, where it was first created, FERC's backstop siting authority provided for FERC to approve siting if a state "withheld approval" of a filed application for more than a year. This authority could be invoked only if a proposed line was in a U.S. Department of Energy's (DOE)-designated "corridor" exhibiting transmission congestion "that adversely affects consumers." However, that authority has been challenged, and two federal circuit court decisions in 2009 and 2011 have effectively neutralized it.

[51] MIT, The Future of the Electric Grid (Dec. 2011)
[52] National Council on Electricity Policy, Coordinating Interstate Electric Transmission Siting (July 2008)

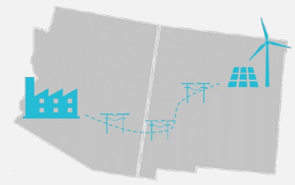
As evidenced by the recent cancellation of several large interstate natural gas pipeline projects, notably including the Atlantic Coast Pipeline and the Constitution Pipeline both terminated in 2020, energy infrastructure development is challenging, even when FERC's siting and eminent domain authorities are employed.

### Varied Environmental Interests

While many clean energy advocates acknowledge the importance of developing new transmission, environmental interests and stakeholders are not monolithic. Some environmental intervenors focus on the impacts of specific corridors, often slowing or stopping permitting and construction, including:

- Concerns about habitat disturbance for endangered species and disturbance of forests, wetlands, and other natural areas
- Potential leaks from high-voltage circuit breakers, switches, and other equipment that are insulated with sulfur hexafluoride
- Concerns about trees and other plants that must be controlled to prevent contact with high-voltage transmission lines

Siting and permitting processes have always been challenging for electric transmission infrastructure. The number of stakeholders and opportunities to intervene in the process leads to delays and cancellations. As opposition to virtually any new infrastructure has increased, these challenges will result in continuing impediments to development of new transmission. These issues are multiplied as transmission lines cross state and regional boundaries.

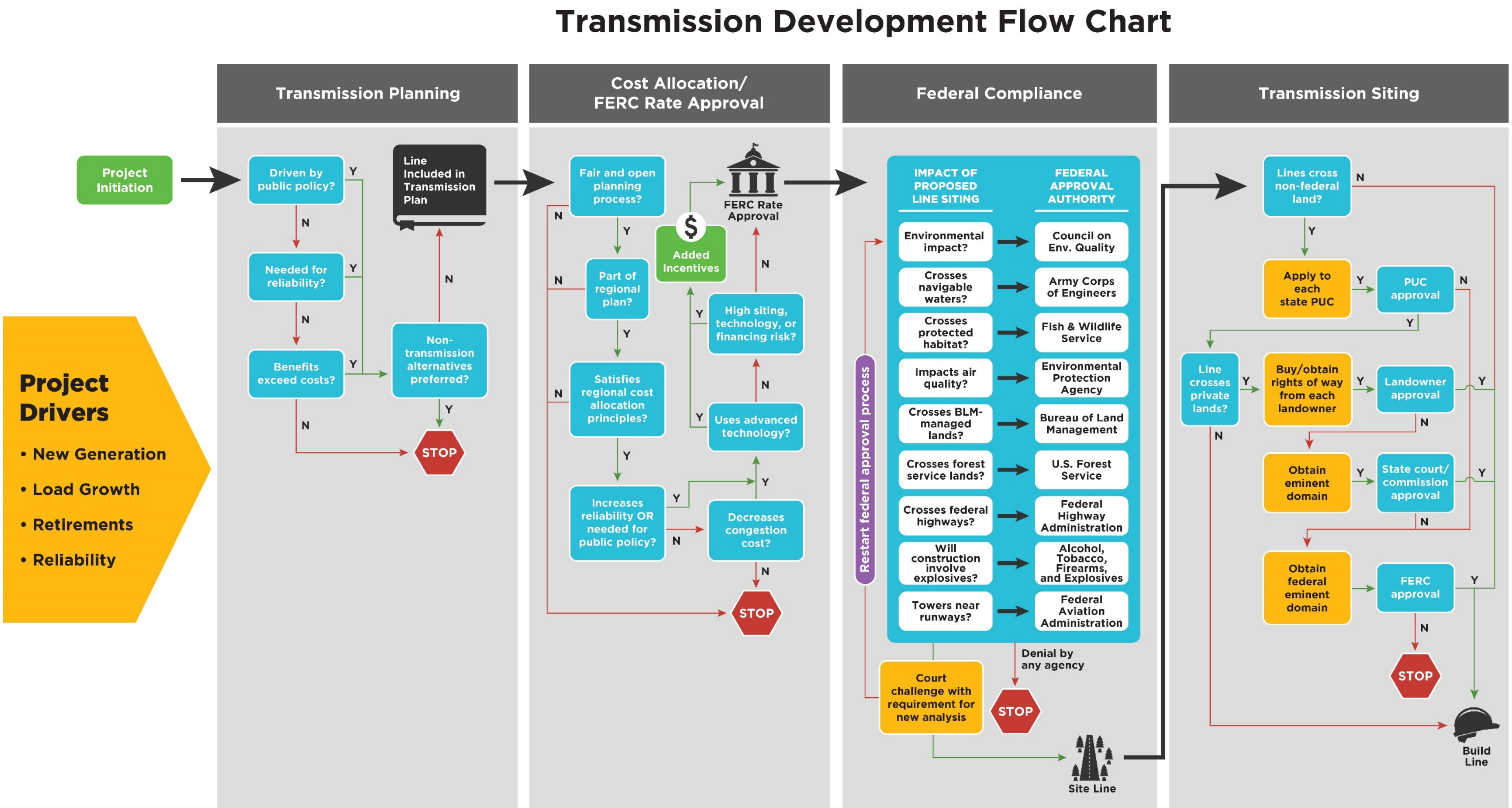


**SunZia Project Highlight**

- SunZia originally proposed two 500 kV transmission lines, spanning 520 miles, to deliver renewable energy from New Mexico to Arizona. The project, with estimated costs of $2B, **started in 2008** and was placed on a regulatory fast-track under the Obama administration.
- In **2015**, the Bureau of Land Management approved the use of federal lands. The following year, SunZia secured its “anchor tenant” renewable project – Pattern Energy’s Corona Wind Farm.
- SunZia then secured a Certificate of Environmental Compatibility from the Arizona Corporation Commission for use of state land.
- In **2018**, New Mexico denied SunZia’s permit to construct due to a lack of clarity on the 320-mile planned segment through the state, which made an environmental impact assessment impossible. There were also complaints from ranchers and landowners of the 90 miles of private property the project would pass through.
- SunZia aims to finalize engineering design by the end of **2021** and permitting by **2022**. It intends to procure materials by **2023** and begin construction by **2025**.

**This project illustrates the challenges faced in developing new transmission lines, as well as the long timeline for finalizing siting and permitting.**

Figure 6.1 – Process Flow Diagram of the Planning, Siting, and Permitting Processes for Transmission in the United States[53]




**Sources:** Americans for a Clean Energy Grid; National Electrical Manufacturers Association

[53] Adapted from National Electrical Manufacturers Association, Siting Transmission Corridors – A Real Life Game of Chutes and Ladders (2017), and Americans for a Clean Energy Grid, Macro Grids in the Mainstream (Nov. 18, 2020), at p. 18

## CONCLUSION

In recent years, utilities, states, corporations, and others have set ambitious clean energy goals that rely heavily on the integration of large amounts of renewables. Given the distance between renewable resources and load centers, transmission will need to be a critical enabler of the clean energy transition. However, federal and state policies have not advanced to support transmission's evolving role.

The difficulties associated with planning, building, and paying for transmission infrastructure have been evident for years. In the early 2000s, the need for transmission to support wholesale markets and to integrate wind resources was well understood. FERC's incentives policy played a role in driving transmission investment in the mid-2000s. FERC Order 1000, issued in 2011, provided guidance for regional planning and cost allocation, and regions have made progress in these areas. Guidance regarding interregional planning was more limited, and those processes have largely stalled.

Incentives for transmission development have become less common, and FERC is now looking to revisit its incentives policy. While FERC Order 1000 addressed elements of transmission planning and cost allocation, the processes remain complex and difficult, and very little progress has been made toward improving interregional planning and development. Siting and permitting remain difficult within single states or regions, substantially more so across multiple jurisdictions. Cost allocation likewise becomes more complex as projects span states and regions.

***Absent major policy changes, transmission development will be a significant obstacle to an orderly clean energy transition.***