CUI

Report on Barriers and Opportunities for High Voltage Transmission

A REPORT TO THE COMMITTEES ON APPROPRIATIONS OF BOTH HOUSES OF CONGRESS PURSUANT TO THE 2020 FURTHER CONSOLIDATED APPROPRIATIONS ACT

Prepared by
Staff of the Federal Energy Regulatory Commission

June 2020

The opinions and views expressed in this staff report do not necessarily represent those of the Federal Energy Regulatory Commission, its Chairman, or individual Commissioners, and are not binding on the Commission.

Table of Contents

I. Executive Summary

The fiscal year 2020 Further Consolidated Appropriations Act (Appropriations Act) was signed into law on December 20, 2019.[1] The report accompanying the Appropriations Act included the following directive:

> FERC is directed to provide to the Committees on Appropriations of both Houses of Congress not later than 180 days after enactment of this Act a study and report outlining the barriers and opportunities for high voltage transmission, including over the nation's transportation corridors. The report shall examine the reliability and resilience benefits, permitting barriers, and any barriers in state or federal policy or markets.[2]

Commission staff has reviewed relevant studies, reports, and analyses, as well as Commission orders, policies, and regulations to identify barriers and opportunities for high voltage transmission.

High voltage transmission can improve the reliability and resilience of the transmission system by allowing utilities to share generating resources, enhance the stability of the existing transmission system, aid with restoration and recovery after an event, and improve frequency response and ancillary services throughout the existing system. High voltage transmission also provides greater access to location-constrained resources in support of renewable resource goals. It also offers opportunities to meet federal, state and local policy goals.

In our exploration of "the barriers and opportunities for high voltage transmission, including over the nation's transportation corridors," staff found that while opportunities exist, there are also barriers which make development of high voltage transmission challenging. For instance, siting of high voltage transmission, generally an area of state jurisdiction, requires navigating each state process or multiple state processes for an interstate high voltage transmission facility. Various other authorizations and reviews are also generally required at the federal, state, and local levels. Additionally, the time required to develop a high voltage transmission facility that meets mandatory Reliability

---

[1] Further Consolidated Appropriations Act, 2020, Pub. L. No. 116-94 (Dec. 20, 2019).

[2] The House Committee on Appropriations included this reporting requirement in House Report 1865, passed December 17, 2019.

Standards, maximizes system benefits, and strikes a balance among interested stakeholders (including states) can be in excess of a decade.

Specific to the nation's transportation corridors, there are several federal and state actions intended to create opportunities for energy infrastructure development, including high voltage transmission, in these corridors. However, future transmission development in existing transportation corridors may be restricted by routing limitations, including state and local prohibitions and restrictions, and safety and technical considerations.

II. Introduction

This report reviews relevant studies, reports, and analyses, as well as Commission orders, policies, and regulations to identify barriers and opportunities for high voltage transmission.

A. Scope of Report

The Congressional directive for the Commission to provide a report outlining barriers and opportunities for "high voltage transmission" did not provide a specific definition of that term. While this term is frequently used by power system engineers across the electric industry, there is not a single agreed upon definition of high voltage transmission. For purposes of this report, Commission staff defines high voltage transmission as alternating current (AC) transmission lines greater than or equal to 345 kV and direct current (DC) transmission lines greater than or equal to 100 kV. To differentiate between AC and DC transmission lines in this report, we refer to AC transmission lines greater than 345 kV as HVAC, DC lines greater than 100 kV as HVDC, and generically refer to both as high voltage transmission.[3] This definition of high voltage transmission includes both overhead and underground lines.

In addition, the Congressional directive for this report does not provide a specific definition of "transportation corridors." Staff consulted the Transportation Security Administration's general use of the term "surface transportation" and determined that, for

---

[3] There are only nine DC transmission projects in the United States: six projects operate at 300 kV or higher and three operate between 100 kV and 300 kV. As transmission assets, these nine projects generally operate similarly on the transmission system and are all considered HVDC in this report. *See, e.g.,* Energy Information Administration, *Assessing HVDC Transmission for Impacts of Non-Dispatchable Generation*, page A-30 (June 2018), https://www.eia.gov/analysis/studies/electricity/hvdctransmission/pdf/transmission.pdf.

purposes of this report, transportation corridors consist of highways, pipelines, both existing and retired or disused railroads (passenger and freight) and canals.[4]

Finally, the Congressional directive for this report includes calls for an examination of the reliability and resilience benefits, permitting barriers, and any barriers in state or federal policy or markets for high voltage transmission. Under section 201(f) of the Federal Power Act (FPA), the Commission has jurisdiction over the rates, terms, and conditions of the transmission of electric energy in interstate commerce by public utilities.[5] Section 215 of the FPA requires a Commission-certified Electric Reliability Organization (ERO) to develop mandatory and enforceable Reliability Standards for the Bulk-Power System that are subject to Commission review and approval.[6] Section 215 of the FPA defines the Commission's jurisdiction to entities that are users, owners, and operators of the Bulk-Power System.[7] In addition, the Commission has limited authority

---

[4] *See generally* Trans. Sec. Admin., *Surface Transportation*, https://www.tsa.gov/for-industry/surface-transportation (discussing the four general modes of land-based transportation as well as maritime transportation); Dep't. of Homeland Sec., *Transportation Systems*, at 135-137 (May 2007), https://www.dhs.gov/xlibrary/assets/Transportation_Base_Plan_5_21_07.pdf (providing a list of transportation assets broken down by sub-sector). *See generally* U.S. Government Accountability Office (GAO), *Issues Associated with High-Voltage Direct-Current Transmission Lines Along Transportation Rights of Way,* at 11 (February 2008), https://www.gao.gov/products/GAO-08-347R (refers to active transportation rights of way as railroads, highways and pipelines).

[5] *See* 16 U.S.C. § 824, 824d, 824e (2018).

[6] 16 U.S.C. § 824o (2018).

[7] The term Bulk-Power System is defined in Section 215 of the FPA and refers to: (1) facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof); and (2) electric energy from generation facilities needed to maintain transmission system reliability. Notably, the Commission's jurisdiction over the Bulk-Power System expressly excludes facilities used in local distribution. With respect to Reliability Standards such as the ones discussed below, North American Electric Reliability Corporation (NERC) uses the term "Bulk Electric System," which is generally defined as transmission facilities that are operated at 100 kV or higher and real power or reactive power resources connected at 100 kV or higher. *See* NERC Glossary, https://www.energy.gov/sites/prod/files/2017/09/f36/NERC%20Glossary.pdf. For

under the FPA to authorize the construction and operation of transmission facilities.[8] Given the limited Commission authority over the siting and construction of high voltage transmission facilities, this report focuses on barriers and opportunities for high voltage transmission, but is not limited to specific actions taken by the Commission or under the Commission's jurisdiction.

III. Discussion

A. Reliability and Resilience Benefits of High Voltage Transmission

The North American electric grid is large and complex. The system reaches thousands of miles and connects thousands of electric generators to millions of end users in the United States and Canada. This infrastructure represents more than 100,000 miles of transmission lines operating at 345 kV and greater.[9] The U.S. Bulk-Power System is made up of three major interconnections: (1) Eastern; (2) Western; and (3) most of the state of Texas (known as Electric Reliability Council of Texas, ERCOT). The stability of the electric grid requires that, within each interconnection, electricity is used the instant it is produced—flowing over transmission lines from generators to consumers. Because the three interconnections are operated independently and are not synchronized, power flow between these three interconnections is accomplished through back to back DC ties – the AC power within one interconnection is first converted to DC power at the point of interconnection and then back to AC power in the neighboring interconnection. AC transmission within each interconnection generally operates like an interconnected web

purposes of this report, staff is using the term Bulk-Power System for both general references to the interconnected grid and specific references to its facilities. In general, the term Bulk-Power System is considered to be broader than Bulk Electric System.

[8] The Commission is authorized to issue licenses for transmission lines transmitting power from non-federal hydropower projects to the point of junction with a distribution system or interconnected transmission system. *See* 16 U.S.C. § 796(11) (2018). In addition, the Commission is authorized to issue backstop siting permits for transmission facilities within a National Interest Electric Transmission Corridor under certain circumstances. *See* 16 U.S.C. § 824p (2018). A 2009 court decision significantly narrowed this already limited backstop transmission siting authority. *Piedmont Environmental Council v. FERC*, 558 F.3d 304 (4th Cir. 2009).

[9] Department of Energy, *Annual U.S. Transmission Data* Review, at 6 (March 2018), https://www.energy.gov/oe/articles/annual-us-transmission-data-review-now-available-0.

and the flow of power follows the path of least resistance. While AC power flows on a transmission line are not specifically controlled by transmission system operators on a line by line basis, DC transmission operates as a specific path with scheduled beginning and ending points.[10]

High voltage transmission is used to carry large amounts of power over longer distances. Transmitting electrical energy at higher voltages reduces line losses, and thus, more of the power transmitted on the line will reach its destination compared to lower voltage transmission lines. For example, one 765 kV line on a 200-foot-wide right-of-way can carry the same amount of power as 15 double circuit 138 kV lines with a combined right-of-way width of 1,500 feet.[11] This means that high voltage transmission has the potential to more efficiently carry power throughout the Bulk-Power System. The reliability and resilience benefits of high voltage transmission that are discussed here include: (1) sharing of resources across regions by improving interregional power transfer capability; (2) aiding with restoration and recovery after an event; (3) improving frequency response; and (4) enhancing the stability of the interconnected transmission system. These four benefits are described in more detail below.

1. Sharing of Resources Across Regions by Improving Interregional Power Transfer Capability

High voltage transmission can improve interregional power transfer capability and thus enables a region to access additional generation in the event that local generation is unavailable to serve customers or maintain reliability.[12] For example, during the winter of 2013-2014, parts of the Midwest, South Central and East Coast regions of the country

---

[10] Federal Energy Regulatory Commission, *Energy Primer – A Handbook of Energy Market Basics*, at 52 (Nov. 2015), https://www.ferc.gov/market-assessments/guide/energy-primer.pdf.

[11] Southwest Power Pool, *The Benefits of a Transmission Superhighway*, https://www.spp.org/documents/10047/benefits_of_robust_transmission_grid.pdf.

[12] For example, the sudden loss of a large amount of generation in a localized area may require grid operators to take emergency actions to support energy balance. NERC, *Special Reliability Assessment: Potential Bulk Power System Impacts Due to Severe Disruptions on the Natural Gas System*, at 20 (Nov. 2017), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SPOD_11142017_Final.pdf.

experienced historic low temperatures, resulting in the loss of capacity from generation.[13] This cold weather event, known as the 2014 polar vortex, caused regions to experience new peak winter electric loads or loads that were close to their all-time winter peak in January 2014.[14] In addition to using voltage reduction and other tools available to maintain reserves and reliable system operation, regions were able to request emergency energy from one another, made possible by the existing transmission system that connects neighboring regional transmission operators.[15] Similarly, the Midwest experienced an extreme cold event in January 2019 that led to high power demand and record natural gas demand (2019 polar vortex). Compared to the 2014 polar vortex, the 2019 polar vortex was significantly colder, although the electricity demand was less than the peak set in 2014. As in 2014, the region experienced generator unavailability, initiated emergency procedures, and depended on the transmission system to import electricity from other regions to meet system needs. Imports during the 2019 polar vortex supplied nine percent of load in a single day, compared to less than three percent in the previous polar vortex.[16]

The ability to share resources across regions, through use of the high voltage transmission system, provides important reliability and resilience benefits when the resources in one area are impacted due to an unexpected disruptive event. However, the potential benefits provided by proposed and existing high voltage transmission are not uniform and need to be studied and verified with detailed simulation modelling of the transmission grid prior

---

[13] NERC, *Polar Vortex Review,* at iii (Sept. 2014), https://www.nerc.com/pa/rrm/January%202014%20Polar%20Vortex%20Review/Polar_Vortex_Review_29_Sept_2014_Final.pdf.

[14] *Id.* at viii.

[15] ISO New England, Inc., *FERC Data Request ISO New England*, at 12 (Jan. 2014), https://www.iso-ne.com/static-assets/documents/pubs/spcl_rpts/2014/iso_ne_response_ferc_data_request_january_2014.pdf.

[16] Energy Information Administration, *Extreme cold in the Midwest led to high power demand and record natural gas demand*, (Feb. 2019), https://www.eia.gov/todayinenergy/detail.php?id=38472#. *See also, MISO January 30-31 Maximum Generation Event Overview*, (Feb. 2019), https://cdn.misoenergy.org/20190227%20RSC%20Item%2004%20Jan%2030%2031%20Max%20Gen%20Event322139.pdf.

to integrating any proposed high voltage transmission solution.

2. Aiding with Restoration and Recovery After an Event

High voltage transmission can also aid with system restoration in two ways. First, if the system experiences a wide-area blackout, system restoration can be enhanced by using adjoining in-service transmission facilities to restore transmission lines, substations, generating plants, and customers to service. For example, the ability to energize transmission from neighboring systems sped the system restoration following the August 2003 blackout.[17] Second, if a local region is impacted by a disruptive event that results in not only a localized blackout, but also unavailability of critical blackstart units that transmission operators count on for system restoration,[18] high voltage transmission can help with system restoration by providing access to resources far from the disruptive event. A joint study conducted by the Commission and the NERC on restoration and recovery plans identified that it is possible to coordinate the use of blackstart facilities across multiple transmission service footprints, thus allowing a blackstart generating unit to contribute to restoring a neighbor.[19]

3. Improving Frequency Response

The three U.S. interconnections (Eastern, Western and ERCOT) generally operate at a frequency of 60 hertz (Hz). Maintaining a consistent frequency is essential to ensure reliability, as frequency deviations may cause equipment damage or power quality degradation. When demand exceeds supply, the interconnection frequency starts to drop below 60 Hz. If this frequency drop is not arrested quickly, generator protection systems will cause the generator to go offline (to prevent damage to the generator), which can worsen the under-frequency condition. To avoid this outcome, interconnections take load offline at certain frequency set points (Eastern and Western less than 59.5 Hz and ERCOT less than 59.3 Hz) to avoid further frequency drops and to restore frequency to

---

[17] NERC, *Special Reliability Assessment: Potential Bulk Power System Impacts Due to Severe Disruptions on the Natural Gas System*, at 11 (Nov. 2017), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SPOD_11142017_Final.pdf.

[18] Reliability Standard EOP-005-3, System Restoration from Blackstart Resources.

[19] FERC and NERC, *Report on the FERC-NERC-Regional Entity Joint Review of Restoration and Recover Plans*, at 5 (May 2018), https://www.ferc.gov/legal/staff-reports/2018/bsr-report.pdf.

60 Hz.[20] One of the main goals of power system planning and operation engineers is to design a system that can bring the supply and demand in balance and to restore the system frequency to 60 Hz within seconds. HVDC lines between neighboring interconnections might help by providing frequency response support from other interconnections when one interconnection experiences a large loss of generation. The extent of this benefit depends on the high voltage transmission design and may vary on a case by case basis.

4. Enhancing the Stability of the Interconnected Transmission System

HVDC transmission projects can also provide a variety of system stability benefits. For example, the Pacific DC Intertie is a long distance HVDC line (±500 kV DC, 3100 megawatts (MW)) that is used to transmit electricity from the Pacific Northwest to Los Angeles. Active modulation of real power in this HVDC line has been deployed as an effective strategy to improve system stability by dampening inter-area modes of oscillation[21] in the Western interconnection.[22]

B. Opportunities for High Voltage Transmission

This section discusses some of the opportunities for high voltage transmission, including through state policy, market initiatives, co-location[23] of transmission within an existing

[20] *Id.* at 11.

[21] Inter-area oscillations refer to a condition when a number of generators in one part of an interconnection resonate against another group of generators in the interconnection. These events, if not attenuated, can eventually lead to system instability and system separation. *See, e.g.,* NERC, *Interconnection Oscillation Analysis Reliability Assessment* (July 2019), https://www.nerc.com/comm/PC/SMSResourcesDocuments/Interconnection_Oscillation_Analysis.pdf.

[22] Inter-area oscillations are common when generation and load are separated by long HVAC transmission lines. IEEE, IEEE Transactions on Power Systems - *Design of the Pacific DC Intertie Wide Area Damping Controller*, Vol. 34, No. 5 (Sept. 2019), https://ieeexplore.ieee.org/stamp/stamp.jsp?tp=&arnumber=8663425.

[23] Co-location refers to the siting of multiple infrastructure projects in the same corridor.

right-of-way, and federal action already taken to encourage transmission planning and development.

1. State Policy Opportunities

High voltage transmission can help states achieve their renewable portfolio standards (RPSs) and renewable portfolio goals. As of June, 2019, 29 states and the District of Columbia have established mandatory RPSs, while an additional eight states have adopted non-binding renewable portfolio goals.[24] These regulatory mandates and voluntary targets are contributing to the build-up of renewable energy resources (e.g., solar, wind, hydropower, and geothermal) that are often located in remote areas far from population centers. Transmission developers have proposed numerous high voltage transmission projects in the United States that could integrate renewable energy resources onto the grid and connect them to regions with high electricity demand.[25] For example, the proposed TransWest Express Transmission Project (TransWest Express) would eventually provide 3,000 MW of transmission capacity to deliver wind energy generated in southern Wyoming to consumers in Arizona, Nevada, and southern California.[26] The project is planned to include 730 miles of high voltage transmission infrastructure consisting of two systems: a 500 kV HVDC system with terminals in Wyoming and Utah; and a 500 kV HVAC system from the Utah terminal to southern Nevada. The proposed route of the transmission line project, shown in Figure 1, would maximize the use of existing and designated utility corridors. If constructed, the TransWest Express could help deliver the renewable energy needed for Arizona, Nevada and California to achieve their RPSs of 15 percent by 2025, 25 percent by 2025, and 60 percent by 2030, respectively.[27]

---

[24] DSIRE, *Renewable & Clean Energy Standard*s, (June 2019), https://s3.amazonaws.com/ncsolarcen-prod/wp-content/uploads/2019/07/RPS-CES-June2019.pdf.

[25] U.S. Energy Information Administration, *Assessing HVDC Transmission Impacts of Non-Dispatchable Generation*, Table 9 (June 2018), https://www.eia.gov/analysis/studies/electricity/hvdctransmission/.

[26] *See generally*, TransWest Express LLC, *Critical grid infrastructure to connect the West*, http://www.transwestexpress.nethttp://www.transwestexpress.net/about/index.shtml.

[27] DSIRE, *Renewable Portfolio Standards and Clean Energy Standards*, (June 2019), https://s3.amazonaws.com/ncsolarcen-prod/wp-content/uploads/2019/07/RPS-

Figure 1: The approximate route of the proposed TransWest Express project[28]

Similarly, high voltage transmission can help states achieve their greenhouse-gas (GHG) emission reduction targets. As of July 2019, 23 states and the District of Columbia have implemented statewide GHG emissions targets to reduce emissions levels by a specified time.[29] New high voltage transmission lines can increase the availability of carbon-free energy and facilitate the replacement of energy generated by fossil fuels, thereby helping states meet their targets by reducing GHG emissions.

2. <u>Market Opportunities for High Voltage Transmission</u>

Multiple market developments–in particular, increasing electrification of the economy, retirement of aging dispatchable resources,[30] and evolution of the generation mix toward renewable energy sources–are likely to create more investment opportunities for

---

CES-June2019.pdf.

[28] *See* TransWest Express, *supra* n. 26.

[29] Center for Climate and Energy Solutions, *U.S. State Greenhouse Gas Emissions Targets*, (July 2019) https://www.c2es.org/document/greenhouse-gas-emissions-targets/.

[30] This includes coal, hydropower, natural gas, and nuclear resources.

transmission developers, including developers of high voltage transmission.

Investment in transmission has been rising for the past two decades, with the current market reaching approximately $20 billion per year, driven in recent years by congestion relief and access to low-cost renewable energy resources.[31] The Brattle Group estimates that in the next decade and beyond, increased electrification of the economy, such as transportation and heating will drive substantially more transmission investment than historic investment levels. The Brattle Group's recent study finds that the U.S. will need an average investment of $3-$7 billion per year through 2030, in addition to investments needed to maintain existing transmission systems and integrate renewable energy generation to meet existing load, to meet the changing needs of the system due to electrification.[32] The study goes on to find that even a large increase in transmission investments would likely have a modest impact on consumer electricity rates (a 1-4 percent increase) before accounting for other electricity savings created by new transmission infrastructure.[33]

The recent CapX2050 study by ten Midwestern utilities found that as dispatchable generation retires and is replaced with load-distant wind generation, the transmission system could require extensive upgrades to provide the capability to move energy between regions and to assure the reliability of the system.[34] The study further notes that the loss of dispatchable generation creates challenges for grid stability and suggests that HVDC technology could offer solutions to replicate the ancillary services traditionally

[31] The Brattle Group, *Improving Transmission Planning: Benefits, Risks, and Cost Allocation*. Presentation to Midwestern Governors Association & Organization of MISO States, at slide 3 (Nov. 2019) https://brattlefiles.blob.core.windows.net/files/17555_improving_transmission_planning_-_benefits_risks_and_cost_allocation.pdf.

[32] The Brattle Group, *The Coming Electrification of the North American Economy*, at ii (Mar. 2019) https://wiresgroup.com/wp-content/uploads/2019/03/Electrification_BrattleReport_WIRES_FINAL_03062019.pdf.

[33] *Id.* at v.

[34] CapX2050, *Transmission Vision Report*, at 5 (Mar. 2020) http://www.capx2020.com/documents/CapX2050_TransmissionVisionReport_FINAL.pdf.

offered by localized, dispatchable generation.[35] A report by the Department of Energy (DOE) Grid Modernization Initiative similarly found that HVDC could relieve congestion and improve grid stability.[36] The CapX2050 study also finds that retirements of dispatchable generation and the movement toward non-dispatchable wind and solar generation will change transmission congestion patterns and introduce more variability in power flows, thus requiring new solutions to mitigate congestion and ensure reliability.[37] Finally, transmission investments improve competition in wholesale markets by reducing congestion and allowing the lowest-cost resources to compete.[38] In 2017, ISO-NE reported that based on proposed new power generation, transmission infrastructure build-out would be needed in the coming years to deliver low-cost energy to load centers.[39] In 2019, ISO-NE reported that transmission investments improve reliability, reduce congestion and uplift costs, and reduce the need for renewable energy curtailments.[40]

---

[35] *Id.* at 4, 35-36.

[36] Pacific Northwest National Laboratory, *Models and methods for assessing the value of HVDC and MVDC technologies in modern power grids*, at 47 (July 2017) https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-26640.pdf.

[37] *Id.* at 3, 41-42.

[38] In many areas of the country, the Bulk-Power System and wholesale electricity markets are operated by independent non-profit regional transmission operators (RTOs) or independent system operators (ISOs) that coordinate, control, and monitor the operation of a multi-state or single state electric transmission grid. The nation's RTOs and ISOs include the ISO New England, Inc. (ISO-NE), the New York Independent System Operator, Inc. (NYISO), PJM Interconnection, L.L.C. (PJM), Midcontinent Independent System Operator, Inc. (MISO), Southwest Power Pool, Inc. (SPP), California Independent System Operator Corporation (CAISO), and ERCOT. ERCOT is not subject to the Commission's jurisdiction under FPA sections 203, 205, or 206.

[39] ISO-NE, *State of the Grid 2017 Presentation,* at slide 21 (Jan. 2017) https://www.iso-ne.com/static-assets/documents/2017/01/20170130_stateofgrid2017_presentation_pr.pdf

[40] ISO-NE, *State of the Grid 2019 Presentation,* at slide 41 (Feb. 2019) https://www.iso-ne.com/static-assets/documents/2019/02/20190220_pr_state-of-the-grid_presentation_final.pdf.

3. Opportunities for Co-location in Transportation Corridors

Various federal and state laws support the co-location of high voltage transmission in transportation corridors. As described above, for the purposes of this report, transportation corridors consist of highways, pipelines, both existing and retired or disused railroads (passenger and freight) and canals.

a. Federal Lands

The Federal Land Policy and Management Act (FLPMA)[41] authorizes the nation's two largest land managers, the U.S. Bureau of Land Management and U.S. Forest Service, to permit various types of land uses on federal lands.[42] This includes the issuance of right-of-way permits for certain types of infrastructure, like transmission, highways, canals, and some pipelines. When issuing right-of-way permits on federal lands, FLPMA directs these agencies to utilize rights-of-way in common (i.e., right-of-way corridors) to the extent practical.[43] In addition, FLPMA requires each right-of-way permit issued to reserve the right to grant additional permits for compatible uses within or adjacent to that right-of-way.[44]

As part of EPAct 2005, Congress enacted section 368 to further promote the co-location of infrastructure on federal lands.[45] Specifically, section 368 directed the Secretaries of Agriculture, Commerce, Defense, Energy, and Interior (collectively, Secretaries) to: (1) designate corridors for oil, natural gas, and hydrogen pipelines and electric transmission and distribution facilities on federal lands in the West; (2) perform any environmental reviews that may be required to complete the designation of such corridors; (3) incorporate the designated corridors into the relevant agency land use and resource management plans; and (4) expedite applications to construct energy infrastructure projects within such corridors.[46] In carrying out this section, the Secretaries were also

---

[41] 43 U.S.C. §§ 1701 et seq. (2018).

[42] *Id.* § 1761 (2018).

[43] *Id.* § 1763 (2018).

[44] *Id.*

[45] 42 U.S.C. § 15926 (2018).

[46] When expediting applications in corridors, section 368 also requires the Secretaries to consider prior analyses and environmental reviews undertaken during the

directed to consider the need for upgraded and new transmission to improve reliability, relieve congestion, and enhance the capability of the national grid to deliver electricity.

To carry out their responsibilities under section 368, the agencies prepared and issued draft and final Programmatic Environmental Impact Statements in 2007[47] and 2008,[48] respectively. Based on the recommendations in these documents, the agencies amended their land use and resource management plans in 2009 to designate approximately 6,000 miles of energy corridors on federal lands.[49] The energy corridors incorporated over 4,000 miles of existing transportation corridors, including various highway and pipeline rights-of-way, for expediting energy infrastructure applications.[50] In addition, most of the energy corridors were designated with a width of 3,500 feet to accommodate the co-location of multiple transmission and pipeline projects in a single corridor.[51]

b. State Energy Corridors

Some states have also enacted laws and policies to promote the co-location of transmission in transportation corridors. Maine, for example, passed a law in 2010 designating energy corridors for the development of transmission and other energy infrastructure along specific highway and pipeline rights-of-way.[52] Maine designated these corridors to provide greater certainty in energy infrastructure planning, siting, and permitting.[53] In addition, lease payments from infrastructure development in these

---

designation of such corridors.

[47] Notice of Availability, 72 Fed. Reg. 64591 (Nov. 16, 2007).

[48] Notice of Availability, 73 Fed. Reg. 72521 (Nov. 28, 2008).

[49] *See* U.S. Forest Service Record of Decision, 74 Fed. Reg. 12306 (March 24, 2009).

[50] *Supra* n. 48 at 2-5.

[51] *Id.* at S-17. Most of the designated corridors are multimodal to accommodate transmission and pipelines; however, some corridors are more restrictive (e.g., transmission only, pipeline only, or underground only).

[52] An Act Regarding Energy Infrastructure Development, LD 1786, Pub. L. 2010, Ch. 655 (2010).

[53] Maine Governor's Office of Energy Independence and Security, *Issues Affecting*

corridors would be used to fund state energy efficiency initiatives and economic incentives for renewable energy development. In 2016, New Hampshire passed a law designating energy corridors along, within, and under specific highway rights-of-way for the underground co-location of transmission and other energy infrastructure.[54] The designation of these corridors was in response to, among other things, the increasing difficulty of siting aboveground transmission from neighboring regions. Other states have adopted various policies encouraging proposed transmission to use existing transportation corridors where practicable.

c. **Other Considerations**

In some cases, the co-location of transmission in transportation corridors could reduce both the negative effects caused by a project and the cost of project development. Siting transmission in transportation corridors could minimize the creation of new rights-of-way on undisturbed lands, which could result in reduced effects on private landowners and environmental, cultural, and visual resources. In addition, it may be less expensive for developers to acquire the right to add transmission to an existing right-of-way with a single owner (i.e., the entity controlling access to the transportation corridor),[55] compared to negotiations with various landowners along a new route.

4. **Federal Transmission Planning Policies and Studies**

Commission policies seek to help achieve appropriate levels of transmission investment to address reliability needs, economic considerations, and needs driven by public policy requirements, while maintaining just and reasonable rates as required under the FPA.[56] In 2011, the Commission issued Order No. 1000 to improve transmission planning processes and cost allocation mechanisms to ensure that the rates, terms and conditions of

---

Co-Location of Energy Infrastructure, at ES-1 (2011), https://www.maine.gov/energy/pdf/LD1786%20Co-Location%20Report%20FINAL%20May%202011.pdf.

[54] Authorizing Energy Infrastructure Development and Designating Energy Infrastructure Corridors, H.B. 626-FN-A, Ch. 126-R (2016).

[55] GAO, *Transmission Lines: Issues Associated with High-Voltage Direct-Current Transmission Lines along Transportation Rights of Way*, at 4 (2008), https://www.gao.gov/assets/100/95342.pdf.

[56] FERC Staff, 2017 Transmission Metrics Staff Report, at 6 (Oct. 2017).

service provided by public utility transmission providers are just and reasonable and not unduly discriminatory or preferential.[57] The Commission stated that changes in the electric utility industry had created a need for potentially significant, new transmission infrastructure, [58] and that the reforms in Order No. 1000 were necessary to ensure that the Commission's transmission planning and cost allocation requirements were adequate to support more efficient or cost-effective investment decisions.[59]

The Commission concluded that inadequate transmission planning and cost allocation requirements were impeding the development of beneficial transmission lines or resulting in inefficient and overlapping transmission development due to a lack of coordination.[60] Accordingly, Order No. 1000's reforms addressed specific deficiencies in the existing transmission planning and cost allocation requirements,[61] including challenges related to: regional transmission planning,[62] participation by nonincumbent transmission developers[63] in regional transmission planning processes,[64] interregional transmission

---

[57] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, 136 FERC ¶ 61,051, at P 1 (2011), *order on reh'g*, Order No. 1000-A, 139 FERC ¶ 61,132, *order on reh'g and clarification*, Order No. 1000-B, 141 FERC ¶ 61,044 (2012), *aff'd sub nom. S.C. Pub. Serv. Auth.* v. *FERC*, 762 F.3d 41 (D.C. Cir. 2014).

[58] Order No. 1000, 136 FERC ¶ 61,051 at PP 44-45.

[59] *Id*. P 46.

[60] *Id.* P 43.

[61] *Id.* P 47.

[62] *See id*. PP 78-83.

[63] *Id.* P 320. "Nonincumbent transmission developer" refers to two categories of transmission developer: (1) a transmission developer that does not have a retail distribution service territory or footprint; and (2) a public utility transmission provider that proposes a transmission project outside of its existing retail distribution service territory or footprint, where it is not the incumbent for purposes of that project. *Id.* P 225. An "incumbent transmission developer/provider" is an entity that develops a transmission project within its own retail distribution service territory or footprint. *Id*.

[64] *See id*. PP 253-257.

coordination,[65] and cost allocation methods to allocate the costs of new regional and interregional transmission facilities.[66]

While previous Commission requirements directed transmission providers to participate in coordinated, open and transparent local transmission planning processes, the Commission observed that, particularly outside of RTO and ISO regions, there was no analysis being conducted at the regional level to identify transmission alternatives that could resolve regional needs more efficiently or cost-effectively than solutions identified in the local transmission plans of individual transmission providers in a region. Accordingly, the Commission required the development of a regional transmission plan that identified more efficient or cost-effective solutions to regional transmission needs. [67]

The Commission observed that there were few processes in place for neighboring regions to determine whether there may be interregional transmission solutions that could meet regional needs more efficiently or cost-effectively. Accordingly, the Commission required each set of neighboring transmission planning regions to develop transparent coordination procedures to share information about common needs and potential solutions that could help identify such potential interregional transmission facilities and to create a process to jointly evaluate such potential solutions.[68] The Commission also required that each set of neighboring regions develop an *ex ante* interregional cost allocation method to allocate the costs of a new interregional transmission facility among beneficiaries of the facility in both regions where the facility is located.[69]

Finally, the Commission noted that potential transmission developers faced a risk in proposing transmission facilities because they did not have assurance of how they would recover the costs of their investments. The Commission stated that failing to address the allocation of costs for new transmission facilities in a way that aligns with the evaluation of benefits could lead to needed transmission facilities not being built.[70] Accordingly, the

---

[65] *See id.* PP 368-370.

[66] *See id.* PP 495-499.

[67] *Id.* PP 82-83.

[68] *See id.* PP 349-350, 368.

[69] *See id.* P 578.

[70] *Id.* PP 484-86, 496-99.

Commission required each region to develop an *ex ante* method for allocating the costs of new transmission facilities that were selected in the regional transmission plan for purposes of cost allocation (in addition to the requirement for neighboring regions to develop *ex ante* cost allocation methods for interregional transmission facilities).[71]

In addition to Order No. 1000, FPA section 219(a) requires the Commission to adopt regulations allowing incentive-based rates for electric transmission for the purpose of benefitting consumers by ensuring reliability and reducing the cost of delivered power by reducing transmission congestion.[72] The Commission implemented this requirement in Order No. 679 by providing applicants that meet the requirements of the rule the ability to request a variety of transmission incentives, including increases above the base return on equity, the ability to request 100 percent of prudently incurred costs associated with abandoned transmission projects to be included in transmission rates if such abandonment is outside the applicant's control, inclusion of 100 percent of construction work in progress in rate base, hypothetical capital structures, accelerated depreciation for rate recovery, and recovery of prudently incurred pre-commercial operations costs as an expense or through a regulatory asset.[73]

On March 20, 2020, the Commission proposed to revise its electric transmission incentives policy to stimulate the development of transmission infrastructure needed to support the nation's evolving generation resource mix, technological innovation and shifts in load patterns.[74] The Commission stated that the reforms, if adopted, would more closely align the Commission's policy with its statutory obligation to provide incentives that benefit consumers by ensuring reliability and reducing the cost of delivered power.

In addition to the Commission's actions, the DOE funds projects and research to facilitate the planning and improvement of the nation's electric power grid. For example, DOE's Grid Modernization Initiative works with public and private partners to develop the

---

[71] *Id.* PP 558, 578.

[72] 16 U.S.C. 824s(a) (2018).

[73] *Promoting Transmission Investment through Pricing Reform*, Order No. 679, 116 FERC ¶ 61,057, *order on reh'g*, Order No. 679-A, 117 FERC ¶ 61,345 (2006), *order on reh'g* 119 FERC ¶ 61,062 (2007).

[74] *Electric Transmission Incentives Policy Under Section 219 of the Federal Power Act*, 170 FERC ¶ 61,204 (2020).

concepts, tools and technologies needed to create the modern grid of the future.[75] The initiative's portfolio of work helps integrate all sources of electricity better, improve the security of our nation's grid, solve challenges of energy storage and distributed generation, and provide a platform for U.S. competitiveness and innovation in a global energy economy.

C. Barriers to High Voltage Transmission

This section discusses barriers to high voltage transmission development, including permitting and planning challenges, access to existing rights-of-way, and federal action that may unintentionally disincentivize transmission planning and development.

1. Permitting Regimes

States generally have jurisdiction over transmission siting and construction. While states have the principal authority to issue siting permits, high voltage transmission projects generally require authorizations and reviews from various regimes at the federal, state, and local levels.

a. State Siting Permits

A certificate of public convenience and necessity (CPCN), or similar permit, is required to construct and operate a transmission project within a state. Depending on the state, the authority to issue a CPCN rests with the state public utility commission, another agency or board (e.g., state corporation commission or dedicated energy siting board), or a combination of agencies. Some states have no siting authority, or their authority is only triggered by certain conditions (e.g., minimum project voltage). While state laws vary, to grant a CPCN, the state must find that a project is in the public interest. States generally conduct a siting process to inform their public interest determinations, which often includes public hearings and economic and environmental reviews of proposed projects.[76]

The siting process is more complex for interstate transmission projects. Developers must adequately demonstrate that their project is in each state's public interest, and states may consider different, and often inconsistent, criteria in making their public interest

[75] Department of Energy, Grid Modernization Initiative, https://www.energy.gov/grid-modernization-initiative.

[76] The environmental reviews are similar to federal reviews under the National Environmental Policy Act, which are described below.

determinations. For example, some state laws restrict a project's consideration to intrastate benefits and costs, whereas others require the consideration of interstate, regional, or national benefits and costs.[77] In addition, some state laws require the consideration of broad environmental or economic benefits and costs, whereas others require the consideration of specific policy goals (e.g., interconnecting specific generation sources).[78]

Interstate transmission projects may also require additional coordination among the relevant states in their project reviews. State laws vary on the extent of such coordination. Some do not address interstate coordination, whereas others encourage states to conduct joint project reviews or enter interstate compacts.[79] Even when interstate coordination occurs, states may determine that the siting decisions of neighboring states are necessary prior to making their own decisions.[80]

The requirement to obtain approvals from each state through which an interstate transmission project will be routed can create a barrier, because many states look only at the intra-state burdens and benefits of a proposed project without considering the project's overall multi-state or regional benefits.[81] This can make it difficult for transmission project developers to obtain the necessary approvals in states where a project provides little or no benefits; for example, in states where few, if any, loads or generation resources are served by the project.[82] This problem may be exacerbated in the

---

[77] Friedman, J., and Keogh, M., *Coordinating Interstate Electric Transmission Siting: An Introduction to the Debate*, The National Council on Electricity Policy, at 11 (2008), https://www.energy.gov/sites/prod/files/oeprod/DocumentsandMedia/Transmission_Siting_FINAL_41.pdf.

[78] *Id.* 11-12.

[79] *Id.* 7.

[80] Eto, J., *Building Electric Transmission Lines: A Review of Recent Transmission Projects*, Lawrence Berkley National Laboratory, at 23 (Sept. 2016), https://emp.lbl.gov/sites/all/files/lbnl-1006330.pdf.

[81] *See, e.g., id*. 24.

[82] *See, e.g.,* Tomich, J., *Battle reignites over $2.5B Midwest transmission line,* EnergyWire (Dec. 2019), https://www.eenews.net/stories/1061847775; Postelwait, J., *Grain Belt Express Transmission Line Moves Forward with Missouri Court Decision*,

future as there is an increasing need to interconnect remote renewable resources, such as hydropower and wind facilities, to the grid using high voltage transmission facilities.

b. Other State and Local Authorizations and Reviews

In addition to CPCNs, high voltage transmission projects require various other authorizations and reviews at the state and local levels. These commonly include, but are not limited to, section 401 water quality certificates under the Clean Water Act,[83] right-of-way permits or easements for state lands, encroachment and accommodation permits, and local zoning permits. Merchant transmission developers must also obtain a permit to operate as a public utility within a state.[84] The filing requirements, review processes, and decision criteria for many of these permits vary by state or locality.

c. Federal Authorizations and Reviews

High voltage transmission projects also require various authorizations and reviews at the federal level. As described above, transmission projects crossing federal lands are required to obtain right-of-way permits from the relevant land management agencies. Long, linear infrastructure, like high voltage transmission projects, frequently cross lands managed by multiple federal agencies.[85] Because these agencies operate under different statutory mandates for managing their lands, they have different information needs and decision criteria to issue right-of-way permits and, if necessary, amend land use and resource management plans.

In deciding whether to issue a right-of-way permit on federal lands, land management

---

T&D World (Mar. 2020), https://www.tdworld.com/overhead-transmission/article/21126570/grain-belt-express-transmission-line-moves-forward-with-court-decision.

[83] 33 U.S.C § 1341 (2018).

[84] Eto, *supra* n. 80 at 3.

[85] The five major land management agencies, listed from most to least lands managed, include the U.S. Bureau of Land Management, Forest Service, Fish and Wildlife Service, National Park Service, and Department of Defense. Congressional Research Service, *Federal Land Ownership: Overview and Data*, R42346, at 3 (2020), https://fas.org/sgp/crs/misc/R42346.pdf.

agencies must comply with the National Environmental Policy Act.[86] The National Environmental Policy Act prescribes a process for assessing the potential environmental effects of federal actions, and any reasonable alternatives, to inform the federal decision-making process. This process includes the solicitation of public and other stakeholder input on potentially affected resources, the development of draft and final Environmental Impact Statements, and the issuance of a Record of Decision (i.e., permitting decision). The development of draft and final Environmental Impact Statements may require extensive coordination between the land management agencies, including their relevant regional and field offices, and other federal agencies with permitting authority.

In addition to right-of-way permits, high voltage transmission projects commonly require various other federal authorizations and reviews, including, but not limited to, permits under section 404 of the Clean Water Act,[87] section 10 of the Rivers and Harbors Act,[88] and the Bald and Golden Eagle Protection Act;[89] consultation under section 7 of the Endangered Species Act[90] and section 106 of the National Historic Preservation Act;[91] and reviews under the Federal Aviation Administration Act.[92]

2. <u>Planning Challenges</u>

Transmission planning across a large transmission network is a complex process through which multiple entities work together to ensure that what happens on one system does not negatively affect other connected systems. There are a variety of planning challenges that arise when developing a plan that spans more than one local power system network. This may require multiple iterations of development, analysis, review, and refinement before all of the planning requirements are met. Those requirements include: meeting

---

[86] 42 U.S.C. §§ 4321 et seq. (2018).

[87] 33 U.S.C § 1344 (2018).

[88] *Id.* § 403.

[89] 16 U.S.C. § 668 (2018).

[90] *Id.* § 1536.

[91] *Id.* § 470f.

[92] 49 U.S.C. § 106 (2018).

mandatory Reliability Standards (specifically transmission planning standards);[93] maximizing system benefits while minimizing total system cost; meeting various state policy goals; and striking a balance among all impacted stakeholders. Developing and finalizing a plan may take a year or more.

As part of the planning process, transmission planners must follow a set of mandatory reliability standards developed by NERC and approved by the Commission.[94] These standards impose requirements on the users, owners and operators of the Bulk-Power System to assure that they fulfill their responsibilities in reliable grid operations, consistent with basic engineering functions and concepts. Reliability Standard TPL-001-4 (Transmission System Planning Performance Requirements) establishes transmission planning performance requirements that address both normal and contingency conditions. Under this standard, responsible entities assess the longer-term reliability of an area, plan for the resource adequacy of specific loads (customer demand and energy requirements), assess the long-term reliability of the interconnected transmission systems in its planning area, and establish transmission system planning performance requirements.

[93] The NERC Reliability Standards TPL-001-4 (Transmission System Planning Performance Requirements) establishes transmission planning performance requirements for transmission planners and planning coordinators to plan their areas of the Bulk-Power System for reliability that address both normal and contingency conditions. Specifically, the Reliability Standard requires planning coordinators and transmission planners to determine whether the contingency conditions cover system can withstand a wide range of probable contingencies or "planning events." On January 23, 2020, the Commission approved version five of the standard, which goes into effect in 2023.

[94] NERC develops mandatory and enforceable Reliability Standards, subject to Commission review and approval. 16 U.S.C. § 824o (2018).

One of the challenges in transmission planning is that there exist a large number of different potential transmission plan alternatives that can take a year or more to evaluate. For example, four different conceptual high voltage transmission systems were proposed (primarily comprised of long distance HVDC lines) in 2010 to interconnect wind resources in the Midwest with load centers in the East.[95] This study evaluated the benefits of four different transmission plans, took over a year to complete, did not include all necessary reliability studies and did not adequately strike a balance among all stakeholders.

In summary, there are a large number of potential alternative transmission topologies that require significant study time to evaluate and determine a workable plan that maximizes reliability and resilience benefits, quantifies the impact on the existing grid and also future plans, minimizes costs, offers a compromise among all stakeholders and satisfies federal, state and local policy goals. Additionally, these planning studies generally do not take into account state and local zoning, permitting requirements, land ownership and easement restrictions.

3. <u>Federal Transmission Planning Rules</u>

As discussed above, the Commission addressed several barriers to the development of transmission infrastructure in Order No. 1000.[96] Some observers argue that there may be post-Order No. 1000 barriers or trends that are impeding high-voltage transmission development.

One trend is the increase in transmission projects being developed outside of Order No. 1000 competitive transmission development processes. Order No. 1000 provided that certain types of projects would not be subject to competitive processes. For instance, Order No. 1000 permits incumbent transmission providers to maintain a federal right of first refusal for local transmission facilities and upgrades.[97] Many regions also have

---

[95] The National Renewable Energy Laboratory, *Eastern Wind Integration and Transmission Study*, at 38 (Feb. 2011), https://www.nrel.gov/docs/fy11osti/47078.pdf.

[96] *See* discussion *supra* III.B.4.

[97] Order No. 1000, 136 FERC ¶ 61,051 at PP 318-319. A local transmission facility is a transmission facility located solely within a public utility transmission provider's retail distribution service territory or footprint that is not selected in the regional transmission plan for purposes of cost allocation. *Id.* P 63. An upgrade is an improvement to, addition to, or replacement of a part of, an existing transmission facility and does not refer to an entirely new transmission facility. Order No. 1000-A, 139 FERC

proposed additional threshold limits and other exceptions to their Order No. 1000 competitive processes. Some factors that determine whether a project is subject to a competitive transmission planning process include voltage levels; cost thresholds; whether costs are allocated solely to the local transmission owner zone or more broadly; the amount of time until the reliability need must be addressed; the type of equipment on which the need arises; and other considerations.[98] Some entities have suggested that incumbent transmission owner utilities may have a preference for developing projects outside of regional competitive transmission planning processes, which may obviate the need for longer-term solutions that might qualify for these processes.[99] Others argue that the transmission development occurring post-Order No. 1000 is focused on reliability and local needs, with only a modest increase in regional projects to address market efficiency and public policy needs.[100]

In addition, some entities suggest that development of interregional transmission facilities, which often could include high voltage transmission, continues to be an area of challenge.[101] These entities argue that there are various limitations in the current interregional transmission coordination processes that limit the effectiveness of those Order No. 1000 reforms.[102] However, others suggest that because regions first focused

---

¶ 61,132 at P 426.

[98] The Brattle Group, *Cost Savings Offered by Competition in Electric Transmission*, 1, 6 (April 2019); Paul L. Joskow, *Competition for Electric Transmission Projects in the U.S.: FERC Order 1000*, 21, 28-29 (March 6, 2019).

[99] *See* GridLiance Post-Conference Comments, Docket No. AD16-18-000, at 10; New England States Committee on Electricity Pre-Conference Comments, Docket No. AD16-18-000, at 5-6; LS Power Pre-Conference Comments, Docket No. AD16-18-000, at 2. These entities claim that the incumbent transmission owner utility's preference is being implemented by using immediate-need reliability projects, which are exempt from competitive transmission development processes, for meeting reliability needs.

[100] Brattle Group, *supra* n. 98, at 17; *see also* LS Power Post-Conference Comments, Docket No. AD16-18-000, at 47; NextEra Energy Transmission Post-Conference Comments, Docket No. AD16-18-000, at 19.

[101] James J. Hoecker, WIRES, Letter to Subcommittee on Energy- Committee on Energy and Commerce, at 2 (May 2018).

[102] For example, some entities argue that one such limitation is that projects often face voltage level or project size restrictions in neighboring regions, leading to the

on and implemented transmission planning and cost allocation within their own regions, interregional transmission coordination processes are still in their beginning stages[103] and there is not enough experience with the interregional transmission coordination process to evaluate how it is working.[104]

Some entities argue that cost allocation continues to present challenges to transmission development.[105] Federal courts have held that a method for allocating the costs of transmission facilities should be evaluated by "comparing the costs assessed against a party to the burdens imposed or benefits drawn by that party."[106] Similarly, Federal courts have held that it is permissible to allocate costs only where the Commission "has an articulable and plausible reason to believe that the benefits are at least roughly commensurate with" the assigned costs.[107] This issue frequently becomes complicated

---

concern that some beneficial interregional projects are not being considered. *See* Southwest Power Pool Pre-Conference Comments, Docket No. AD16-18-000, at 3. Another concern relates to differences in how regions evaluate interregional projects, such as that an interregional project that could meet a reliability need in one region but not in a neighboring region may not be considered, even if that project could provide a market efficiency benefit or address a transmission need driven by public policy in the second region. *See* Josh Rawley, *Assessing the Effectiveness of FERC Order 1000*, 11-12 (2019); Congressional Research Service, *Electricity Transmission Cost Allocation*, 20 (December 18, 2012); *See* James J. Hoecker, WIRES, Letter to Subcommittee on Energy-Committee on Energy and Commerce, 2 (May 9, 2018); Northern Indiana Public Service Post- Conference Comments, Docket No. AD16-18-000, at 2; Midcontinent ISO Post-Conference Comments, Docket No. AD16-18-000, at 28-30.

[103] ScottMadden, Inc., *Informing the Transmission Discussion*, at 6 (January 2020).

[104] *See* California ISO Post-Conference Comments, Docket No. AD16-18-000, at 3, 72-73; Eastern Interconnection Planning Collaborative Post-Conference Comments, Docket No. AD16-18-000, at 4.

[105] Congressional Research Service, *Electricity Transmission Cost Allocation*, 2, 21-22 (Dec. 2012).

[106] *Midwest ISO Transmission Owners v. FERC*, 373 F.3d 1361, 1368 (D.C. Cir. 2004).

[107] *Illinois Commission v. FERC*, 576 F.3d 470, at 477 (7th Cir. 2009).

because, while costs of a new transmission facility are relatively easy to quantify, the associated benefits that result from an improved transmission grid are often difficult to quantify with precision. In Order No. 1000, the Commission offered transmission planning regions considerable flexibility to develop cost allocation methods so long as they meet certain cost allocation principles. Consistent with that approach, each transmission planning region has established thresholds for cost allocation based on its view of how costs and benefits accrue to various stakeholders.[108] Given this complexity and the general contentious nature of cost allocation issues, cost allocation determinations may continue to be prone to disagreement and litigation that present a challenge to development of transmission facilities, including high-voltage transmission.

Notwithstanding these challenges, some states and regions have been working together to identify potential improvements to their respective interregional transmission coordination processes with the goal of furthering interregional transmission development. For instance, the SPP Regional State Committee (RSC) and Organization of MISO States (OMS) Liaison Committee have led a seams coordination effort with the goal of identifying potential improvements in certain areas, including ensuring equal consideration of beneficial regional and interregional projects in transmission planning, and working with SPP and MISO to implement their recommendations.[109] In May 2019, consistent with recommendations provided to the RSC/OMS Liaison Committee,[110] SPP and MISO jointly filed with the Commission revisions to their Joint Operating Agreement to implement changes to their interregional transmission coordination process. Specifically, SPP and MISO proposed, and the Commission accepted in July 2019, to eliminate use of a joint and common model to evaluate a proposed interregional transmission project, include avoided project costs as a benefit metric for all potential interregional transmission projects regardless of the primary project driver, and remove a $5 million minimum cost threshold for a project to be eligible as an interregional

---

[108] ScottMadden, *supra* n. 103, at 28.

[109] RSC/OMS Liaison Committee, *Goals and Guiding Principles* (Oct. 2018), https://www.misostates.org/images/stories/Filings/SPP_RSC_Documents/Item_7_SPP_RSC_OMS_Goals_and_Guiding_Principles_10_1_18.pdf.

[110] MISO and SPP, *Seams White Paper*, at 33-34 (Nov. 2018), https://www.spp.org/documents/59006/spp-miso_rsc_oms_response_spp_miso_final_v3.pdf.

transmission project.[111]

The Commission accepted similar revisions to the MISO and PJM Joint Operating Agreement in December 2019 also to remove the requirement for a joint model for joint evaluation of a proposed interregional transmission project.[112] The Commission has also accepted a proposal by PJM and MISO to create a new category of interregional transmission projects called Targeted Market Efficiency Projects (TMEPs) to address historical congestion along the MISO-PJM seam that did not meet the then-applicable voltage and cost threshold criteria for selection as interregional economic transmission projects in the PJM-MISO interregional coordination process, as well as a method for allocating the costs of these transmission projects between MISO and PJM.[113]

4. Barriers to Co-location in Transportation Corridors

As described above, there are various federal and state laws that support the co-location of high voltage transmission in transportation corridors. However, there are also policies and other considerations that may pose challenges to such co-location.

a. Prohibitions and Restrictions

In some transportation corridors, the co-location of utility facilities (like transmission) is prohibited or restricted by the relevant regulatory authority. For highways, the authority to regulate the use of rights-of-way to accommodate utility facilities is shared between the Federal Highway Administration (FHWA) and state transportation agencies. State transportation agencies develop utility accommodation policies outlining the procedures, criteria, and standards they will use to review and approve individual applications for utility facilities.[114] These policies address a range of considerations, including safety, aesthetics, and the cost or difficulty of highway and utility construction and

---

[111] *Midcontinent Indep. Sys. Operator, Inc.*, 168 FERC ¶ 61,018 (2019).

[112] *PJM, Interconnection, L.L.C.*, 169 FERC ¶ 61,168 (2019).

[113] PJM and MISO explained that TMEPs were intended to "fill the gap" left by the PJM-MISO interregional coordination process and would complement, rather than displace, that existing process. *PJM, Interconnection, L.L.C.*, 161 FERC ¶ 61,005, at P 5 (2017).

[114] 23 C.F.R. § 645.211 (2019).

maintenance.[115] FHWA then reviews and approves these state-developed policies for consistency with federal guidelines.[116]

While FHWA has determined that the use of highway rights-of-way to accommodate utility facilities is in the public interest under certain conditions,[117] states are authorized to decide, as a matter of policy, if they will allow transmission and other utility facilities in highway rights-of-way and, if so, under what conditions.[118] Some states' utility accommodation policies expressly prohibit transmission and other longitudinal utility facilities in highway rights-of-way. Others restrict the co-location of transmission in highway rights-of-way based on various factors (e.g., transmission voltage or specific highway features). These restrictions may preclude the development of high voltage transmission or require the widening or paralleling of existing highway rights-of-way. There could also be prohibitions and restrictions on transmission development in other types of transportation corridors depending on the relevant authority.

b. Other Routing Limitations

Although co-locating high voltage transmission in transportation corridors could reduce development costs,[119] these potential cost savings may be offset by locational limitations. For example, transportation corridors may not run in directions that are compatible with the purpose of proposed transmission. Co-locating transmission in such transportation corridors would likely be inefficient, resulting in longer, more costly infrastructure. In addition, because co-location often requires the widening of existing rights-of-way, it may not remove some of the barriers to siting transmission.

c. Electrical Interference

Electrical interference from high voltage transmission can adversely affect the operation

---

[115] *Id.*

[116] *Id.* § 645.215(b).

[117] *Id.* § 645.205(a). When the uses and occupancy of the highway right-of-way do not adversely affect highway or traffic safety, or otherwise impair the highway or its aesthetic quality.

[118] *Id.* § 645.211(c)(5).

[119] GAO, *supra* n. 55.

and safety of co-located infrastructure, including natural gas and oil pipelines and railroads. The potential for interference from HVAC or HVDC transmission lines is project specific and determined by the design of the project. Below we discuss some potential types of interference. For pipelines, the primary interference effect during operations is inductive coupling.[120] Inductive coupling occurs when AC[121] on a transmission line generates an electromagnetic field around the conductor that induces a current on a nearby buried pipeline.[122] In general, the greatest interference levels occur when transmission is located directly above or closely paralleling the pipeline.[123]

This electrical interference can compromise the integrity and safety of co-located pipelines. Electrical interference associated with high voltage transmission can disrupt the operation of the protection systems used by many oil and natural gas pipelines and accelerate corrosion, resulting in pitting or leaks.[124] In addition, induced voltage from

---

[120] Finneran, S., *Criteria for Pipelines Co-Existing with Electric Power Lines*, Det Norske Veritas, Inc. for the INGAA Foundation, Inc., at 11 (2015), https://www.ingaa.org/File.aspx?id=24732.

[121] Under normal operations, the effects of inductive coupling from DC transmission tend to be negligible. Canadian Association of Petroleum Producers, *Influence of High Voltage DC Power Lines on Metallic Pipelines*, EA-2014-0207, at 1-3 (2014), https://www.capp.ca/wp-content/uploads/2019/11/HVDC_Mitigation_Guidelines_for_Pipelin-249167.pdf.

[122] Finneran, *supra* n. 120.

[123] Pharris, T.C. and R.L. Kolpa, *Overview of the Design, Construction, and Operation of Interstate Liquid Petroleum Pipelines*, Argonne National Laboratory, ANL/EVS/TM/08-1, at 41 (2007), http://corridoreis.anl.gov/documents/docs/technical/APT_60928_EVS_TM_08_1.pdf. Electrical interference is also affected by co-location length, magnitude of transmission current (i.e., amps), pipeline depth and diameter, and soil resistivity.

[124] *Id.* at 43. In addition to HVAC transmission, ground return current from HVDC transmission can have this effect on protection systems, resulting in pipeline damage. This effect must be considered in the HVDC design process. Holt, R.J. et al. *HVDC Power Transmission Electrode Siting and Design*, Oak Ridge National Laboratory, ORNL/Sub/95-SR893/3, at 77-81 (1997), https://digital.library.unt.edu/ark:/67531/metadc697480/m2/1/high_res_d/580585.pdf.

co-located transmission can compromise the safety of personnel touching or standing near pipeline facilities.[125] These effects can be mitigated, but that may require costly modeling, field monitoring, and mitigation systems.[126]

Electrical interference from high voltage transmission can also adversely affect co-located railroads. Like pipelines, AC transmission can induce a current on a nearby railroad (i.e., the steel rails conduct electricity). Because railroads generally use the conductive nature of the rails to operate their signaling systems (e.g., crossing arms), this electrical interference can disrupt the operation of these signals, damage related equipment, or shut down railroad operations.[127] These effects can be mitigated, but they may require costly railroad induction studies (i.e., modeling and field monitoring) and mitigation systems.[128]

d. Safety and Security

The physical proximity of co-located infrastructure can create additional safety and security concerns. There is an increased risk of an accident or failure (e.g., train derailment, transmission tower failure, or fire) compromising the integrity or safety of the co-located infrastructure.[129] In addition, construction or maintenance activities could expose personnel to safety hazards from the co-located infrastructure.[130] Lastly, co-located infrastructure may be a more desirable terrorist target than the facilities would be on their own.[131]

---

[125] Finneran, *supra* n. 120 at 14.

[126] *Id.* at 3.

[127] Cisko, R., *The Effect of Transmission Lines on Railroads*, T&D World (Oct. 2018), https://www.tdworld.com/overhead-distribution/article/20971744/the-effect-of-transmission-lines-on-railroads.

[128] *Id.*

[129] GAO, *supra* n. 55.

[130] Utility accommodation policies can mitigate some of these risks through the implementation of industry safety standards and coordination procedures.

[131] GAO, *supra* n. 55.

D. Other Transmission Corridors

The balance of this paper considers the barriers and opportunities for high voltage transmission, including over the nation's transportation corridors. As an additional consideration, Commission staff offers examples of transmission development facilitated by other designated zones or corridors in the United States and the European Union.

1. Texas Competitive Renewable Energy Zones

The Commission does not have jurisdiction over the rates, terms, and conditions of service for transmission of electric energy occurring wholly within ERCOT, which comprises most of Texas. Therefore, in addition to having jurisdiction over the siting and construction of transmission within Texas, the state has jurisdiction over transmission planning in ERCOT. Texas serves as an interesting example of transmission development facilitated by other designated zones or corridors.

In July 2005, the Texas State Legislature passed Senate Bill 20 (SB 20), which revised the Texas Public Utility Regulatory Act to require the Public Utility Commission of Texas (PUCT) to, among other things: (1) designate competitive renewable energy zones (CREZs) throughout Texas in areas in which renewable energy resources and suitable land areas are sufficient to develop generating capacity from renewable energy technologies; and (2) develop a plan to construct transmission capacity necessary to deliver to electric customers, in a manner that is most beneficial and cost-effective to the customers, the electric output from renewable energy technologies in the competitive renewable energy zones.[132] SB 20 did not specify the amount of generation or transmission capacity required to locate in CREZs or the location of those zones.

Based on the results of a wind resource potential study conducted for ERCOT and its assessment of financial commitments from wind developers in nominated zones, the PUCT issued an interim order in late 2007 designating five CREZs in West Texas.[133]

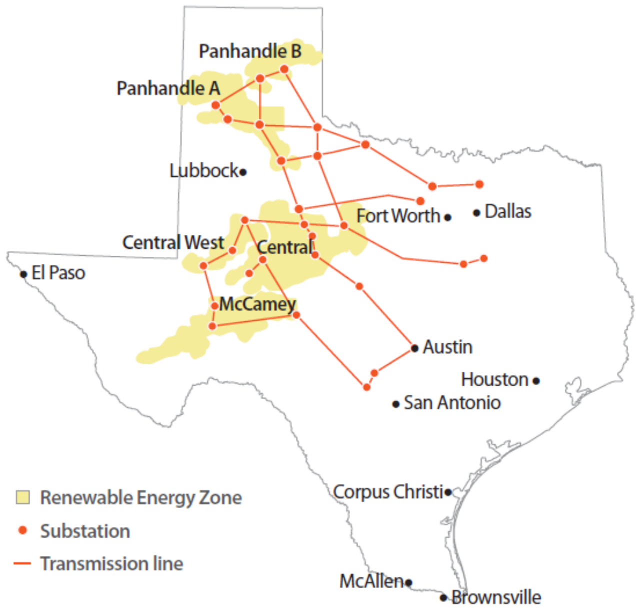
---

[132] Texas Public Utility Regulatory Act, 1999, *Utilities Code. 76th Leg., Ch. 405*, §39.904(g), https://statutes.capitol.texas.gov/Docs/UT/htm/UT.39.htm#39.904.

[133] The five identified CREZs are Panhandle A, Panhandle B, McCamey, Central, and Central West. *See* Billo, J. (ERCOT), *The Texas Competitive Renewable Energy Zone Process* (Sept. 2017), https://cleanenergysolutions.org/sites/default/files/documents/jeff-billo_webinar-ercot-crez-process.pdf. *See also Commission Staff's Petition for Designation of Competitive Renewable Energy Zones,* Interim Order on Reconsideration, Docket No. 33672 (PUCT

The PUCT required that ERCOT and stakeholders conduct studies to help the PUCT evaluate the transmission improvements necessary to serve the generation expected to locate in the designated CREZs, based on four scenarios of MW transfer capability.[134]

Figure 2: Five Designated CREZs and Necessary Transmission Infrastructure[135]



In its final order in this proceeding, the PUCT determined based on ERCOT's studies that a large number of transmission enhancements – including 2,376 miles of right-of-way for mostly new single- and double-circuit 345 kV transmission lines and associated substation, reactive support, and other enhancements – were necessary across all five CREZs to deliver the estimated 18,456 MW of renewable energy generated in the zones to customers in the most beneficial and cost-effective manner. The PUCT estimated the

---

Nov. 2007).

[134] PUCT, *Commission Staff's Petition for Designation of Competitive Renewable Energy Zones,* Interim Order on Reconsideration, Docket No. 33672, at 24-25 (Nov. 2007).

[135] Lee, N. et al. (NREL), *Renewable Energy Zone Transmission Planning Process: A Guidebook for Practitioners*, at 13 (Sept. 2017), https://www.nrel.gov/docs/fy17osti/69043.pdf.

cost of the necessary transmission enhancements at $4.93 billion.[136]

In 2009, the PUCT selected the transmission service providers – both incumbents and new entrants – to build the 72 new transmission circuits. Permitting and construction began in 2009 and the last projects were completed by January 30, 2014. The final cost of the Texas CREZ projects totaled $6.9 billion for approximately 3,600 miles of right-of-way.[137]

ERCOT's post-hoc analysis of the Texas CREZ process identified a number of technical and policy-related lessons learned, including that the CREZ eliminated transmission bottlenecks that could have delayed the development of wind generation, and that competition among transmission providers provided an incentive to complete projects in a timely manner.[138] The Texas CREZ process has been cited as a model for the development of renewable energy zones in other jurisdictions.[139]

2. Western Renewable Energy Zones

In May 2008, the Western Governors' Association (WGA) and the U.S. Department of Energy launched the Western Renewable Energy Zones (WREZ) initiative, the purpose of which was to facilitate the construction of new, utility-scale renewable energy facilities and any needed high voltage transmission to deliver the energy to population centers across the Western Interconnection (which encompasses 11 U.S. states, two Canadian provinces, and areas of northern Mexico).[140] The WREZ initiative emerged out

---

[136] PUCT, *supra* n. 134 at 11-16.

[137] Lasher, W. (ERCOT), *The Competitive Renewable Energy Zones Process* (Aug. 2014), https://www.energy.gov/sites/prod/files/2014/08/f18/c_lasher_qer_santafe_presentation.pdf.

[138] Billo, J. (ERCOT), *The Texas Competitive Renewable Energy Zone Process*, at 21 (Sept. 2017), https://cleanenergysolutions.org/sites/default/files/documents/jeff-billo_webinar-ercot-crez-process.pdf.

[139] Lee, N. et al. (NREL), *Renewable Energy Zone Transmission Planning Process: A Guidebook for Practitioners*, (Sept. 2017), https://www.usaid.gov/sites/default/files/documents/1865/69043.pdf.

[140] WGA and DOE, *Western Renewable Energy Zones – Phase 1 Report: Mapping Concentrated, High Quality Resources to Meet Demand in the Western Interconnection's*

of Western stakeholders' recognition that "while vast renewable resources exist through the West, many reside in remote areas without ready or cost effective access to transmission," and that lack of such transmission access was the major impediment to the development of utility-scale renewable resources in the region.[141]

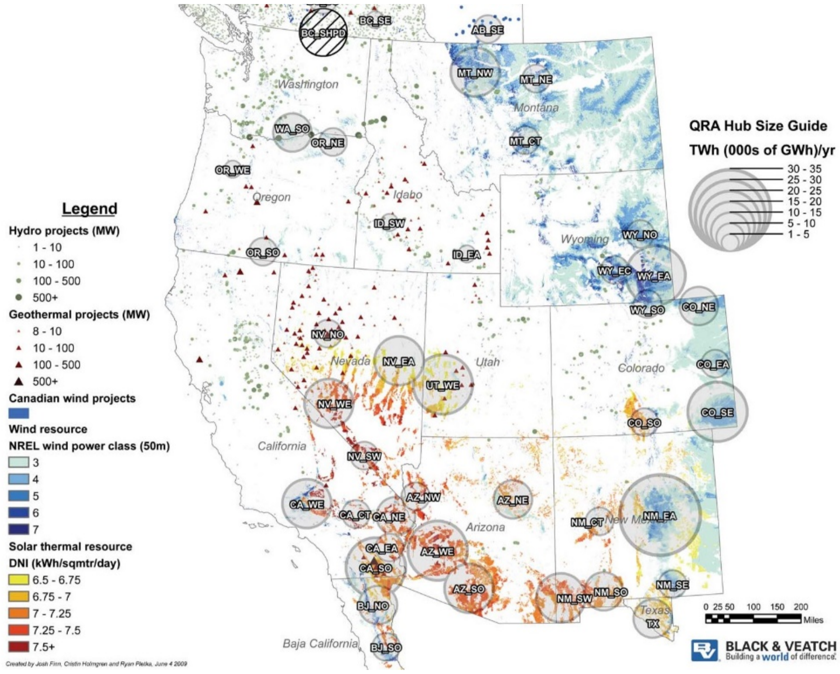
The initiative was divided into four phases: (1) identifying WREZs by taking into account renewable resource potential and various regulatory, statutory, and geographic constraints; (2) developing modeling tools to estimate the relative economics of delivering energy from WREZs to specific load centers across the Western Interconnection; (3) facilitating the development of a region-wide market for renewable power by coordinating power purchases by municipal, cooperative, state, federal, and provincial entities; and (4) addressing the political and regulatory obstacles to the permitting and construction of cross-jurisdictional transmission lines and renewable energy projects, as well as any barriers to coordinated purchasing by load-serving entities.[142]

Distant Markets, at 2-3 (June 2009), https://www.energy.gov/sites/prod/files/oeprod/DocumentsandMedia/WREZ_Report.pdf. The report defines the term "utility-scale" to mean the potential to develop 1,500 MW of solar or wind, or 500 MW of biomass, geothermal, or hydropower generating capacity.

[141] *Id.* at 3.

[142] *Id.* at 18-19.

Figure 3: Western Renewable Energy Zone Qualified Resource Areas (QRAs)[143]



Phase I resulted in the identification of a number of areas with renewable energy generating potential sufficient to justify the construction of at least a 500kV AC transmission line. Figure 3 shows these Qualified Resource Areas, which had at least 1,500 MW of high-quality renewable energy within a 100-mile radius.[144]

Subsequent phases of the WREZ initiative involved the development of economic modeling tools to provide estimates of renewable resource-specific capital costs, transmission delivery and grid integration costs, and energy and capacity values.[145]

---

[143] WGA, *supra* n. 140 at 12-13. To conserve space, the excerpted map excludes QRAs in Canadian provinces.

[144] *Id.* at 10.

[145] Regulatory Assistance Project for WGA, *Renewable Resources and Transmission in the West: Interviews on the Western Renewable Energy Zones Initiative,* at 6-11 (Mar. 2012), https://www.raponline.org/knowledge-center/renewable-resources-and-transmission-in-the-west-interviews-on-the-western-renewable-energy-zones-initiative/.

In addition, the WGA interviewed stakeholders to gather information regarding the modeling results and potential collaboration to develop WREZ hubs. The interviews revealed, among other things, that: (1) utilities' preferences for renewable energy areas did not align with resources determined to be most economic by WREZ modeling; (2) utilities were interested in developing renewable resources in or close to their service territories unless transmission to more distant WREZ hubs already existed; (3) utilities and most state regulators believed that in-state preferences for renewable resources should be eliminated in order to allow utilities to access the most economic resources over larger geographic areas; (4) inconsistent and uncertain state and federal policies posed a barrier to efficient development of renewable resources; (5) utilities and government officials recommended that subregional transmission planning groups identify optimal transmission build-outs to WREZ hubs of common interest, rather than focus solely on system problems such as congestion; and (6) regulatory lag (i.e., the amount of time between expenditures and cost recovery) made utilities reluctant to invest in long lead-time and capital-intensive projects.[146]

According to the WREZ Charter, the aim of the fourth and final phase of the initiative was to "develop proposals for coordinating permitting of interstate transmission projects across state lines and for resolving cost allocation issues of the commercial projects" that result from earlier phases.[147] Based on publicly available information, it appears that the WREZ initiative may have concluded before reaching this final phase.

IV. <u>Conclusion</u>

In our review of the reliability and resilience benefits of high voltage transmission we found that high voltage transmission, as individual lines or as an overlay, can improve reliability by allowing utilities to share generating resources, enhance the stability of the existing transmission system, aid with restoration and recovery after an event, and improve frequency response and ancillary services throughout the existing system. In our exploration of "the barriers and opportunities for high voltage transmission, including over the nation's transportation corridors," staff found that while opportunities exist, there are also barriers which make development of high voltage transmission challenging.

With respect to opportunities, federal and state actions to promote and incentivize transmission development and to encourage collaborative planning of the transmission

---

[146] *Id.* at vi – x.

[147] WGA, *Western Renewable Energy Zones Charter*, (May 2008), https://www.greeningthegrid.org/Renewable-Energy-Zones-Toolkit/topics/wrez-charter.

system provide a framework for high voltage transmission development.

With respect to barriers, siting of high voltage transmission, generally an area of state jurisdiction, requires navigating each state process or multiple state processes for an interstate high voltage transmission facility. Various other authorizations and reviews are also generally required at the federal, state, and local levels. Additionally, the time required to develop a high voltage transmission facility that meets mandatory Reliability Standards, maximizes system benefits, and strikes a balance among interested stakeholders (including states) can be in excess of a decade.

Specific to the nation's transportation corridors, as discussed above there are several federal and state actions intended to create opportunities for energy infrastructure development, including high voltage transmission, in these corridors. However, future transmission development in existing transportation corridors may be restricted by routing limitations, including state and local prohibitions and restrictions, and safety and technical considerations.