U.S. DEPARTMENT OF ENERGY

National Transmission Needs Study

Draft for Consultation and Public Comment
July 2026

United States Department of Energy
Washington, DC 20585

Executive Summary

The nation's energy dominance hinges on a robust transmission system capable of reliably, securely, and economically delivering electricity to load to all locations on the grid in real time. Several of President Trump's executive orders (EOs) highlight the importance of unleashing American energy in support of a robust electric grid, including:

- EO 14262, *Strengthening the Reliability and Security of the United States Electric Grid*;
- EO 14154, *Unleashing American Energy;*
- EO 14213, *Establishing the National Energy Dominance Council*;
- EO 14260, *Protecting American Energy from State Overreach; and*
- EO 14270, *Zero-Based Regulatory Budgeting to Unleash American Energy*.

However, the operational challenges of the electric grid are evolving in complexity and magnitude: Load growth is accelerating with construction of new data centers; cyber security and physical risks to United States (U.S.) infrastructure threaten the electrical infrastructure that our health and economy depend on; and load-serving entities strive to provide reliable electrical service at low cost to consumers. Transmission operators are confronted with these new challenges amid aging transmission infrastructure and a resource mix that is shifting in generation type and location. The U.S. Department of Energy (DOE or the Department) provides for consultation and public comment this draft of the *2026 National Transmission Needs Study* (Needs Study) pursuant to section 216(a)(1) of the Federal Power Act (FPA)[1] to identify transmission needs currently harming consumers or expected to do so in the future and that could be alleviated by transmission solutions. The Needs Study can be used to inform regional and interregional planning as well as help guide the Department in the execution of its transmission-related authorities.

The Needs Study provides a comprehensive assessment of current and future transmission needs within and across geographic regions of the U.S. (*see* Figure ES-1). The definition of electric transmission need used in this study is consistent with FPA section 216(a)(1)–(2): the existence of present or expected electric transmission capacity constraints or congestion in a geographic area. Geographic areas where a transmission need exists would benefit from an upgraded, uprated, or new transmission facility—including alternative solutions—to improve the reliability and resilience of the power system; alleviate transmission congestion and unscheduled flows; alleviate power transfer capacity limits between neighboring regions; deliver cost-effective generation to meet demand; and/or meet projected future generation, electricity demand, or reliability requirements.

[1] "Not later than 1 year after August 8, 2005, and every 3 years thereafter, the Secretary of Energy (referred to in this section as the 'Secretary'), in consultation with affected States and Indian Tribes, shall conduct a study of electric transmission capacity constraints and congestion" 16 U.S.C. § 824p(a)(1).

The Needs Study includes an analysis of transmission system operational data (informed by publicly available information) and a review of more than 120 recently published reports. The purpose of this study is not to prescribe particular solutions to issues faced by the nation's power sector, but rather to assess need in order for industry and the public to suggest the best possible solutions for addressing them in a timely manner. The key findings from the Needs Study are summarized below.

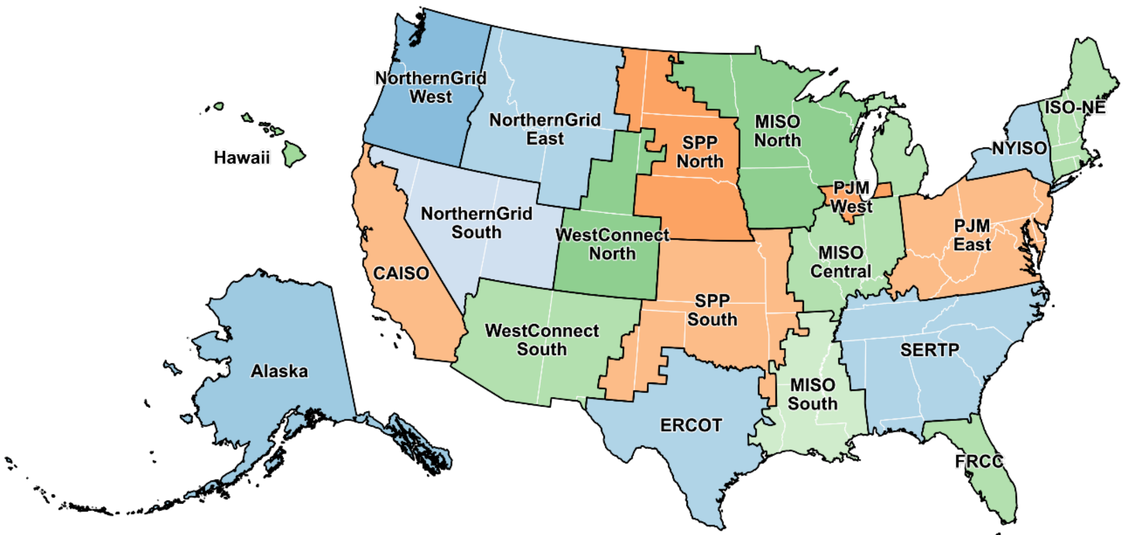
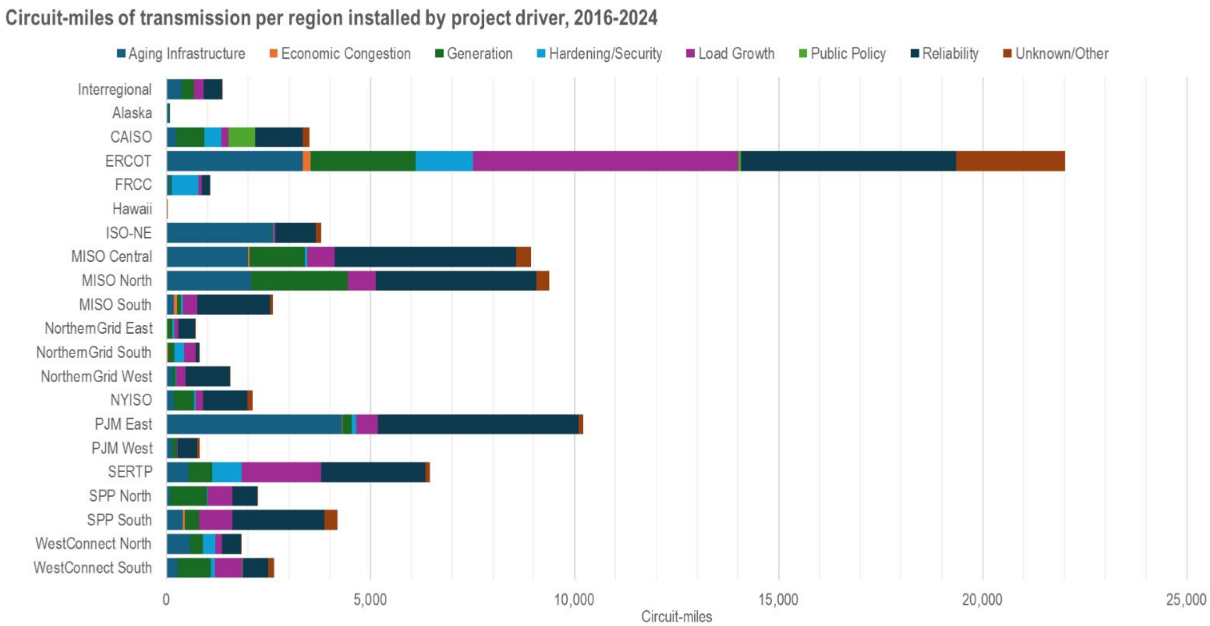


Figure ES-1. Geographic regions used in the Needs Study.

Transmission investments have maintained a steady pace since 2016, although the rate of investment varies considerably by region, with reliability primarily driving historical transmission investment and incumbent utilities installing the vast majority of these projects.

A review of historical transmission system data from 2016 to 2024 provides insight into key indicators that demonstrate the need for increased transmission capacity. Transmission investments have maintained at a steady pace for the U.S. as a whole during the years 2016 to 2023, energizing between 8,700 to 12,500 circuit-miles each year. Investment levels do exhibit considerable regional variation. The Electric Reliability Council of Texas (ERCOT) region installed the most circuit-miles, while regions such as ISO New England (ISO-NE) and New York Independent System Operator (NYISO) demonstrate notably high capital costs for transmission investment per unit of load, reflecting substantial investment relative to the volume of electricity delivered by their transmission systems. These investments resulted in a national total of 85,000 circuit-miles of newly constructed, upgraded, or rebuilt transmission lines rated above 69 kilovolts (kV), which were energized between 2016 and 2024.

Approximately 40% of the total circuit-miles across the nation were driven by reliability needs, although other factors play crucial roles such as load growth, aging infrastructure, and generation interconnection (*see* Figure ES-2). Incumbent utilities or transmission owners—entities that develop transmission within their own retail distribution footprint—dominated the transmission facility development space nationwide, building 98% of all circuit-miles between 2016 and 2024.



Source: Data from Yes Energy Transmission Database (Yes Energy, 2025).

Note: Data for Alaska and Hawaii may be limited and/or incomplete due to a limitation in the database.

Figure ES-2. Circuit-miles for new, upgraded, or rebuilt transmission lines (≥69 kV) energized between 2016 and 2024, by project driver.

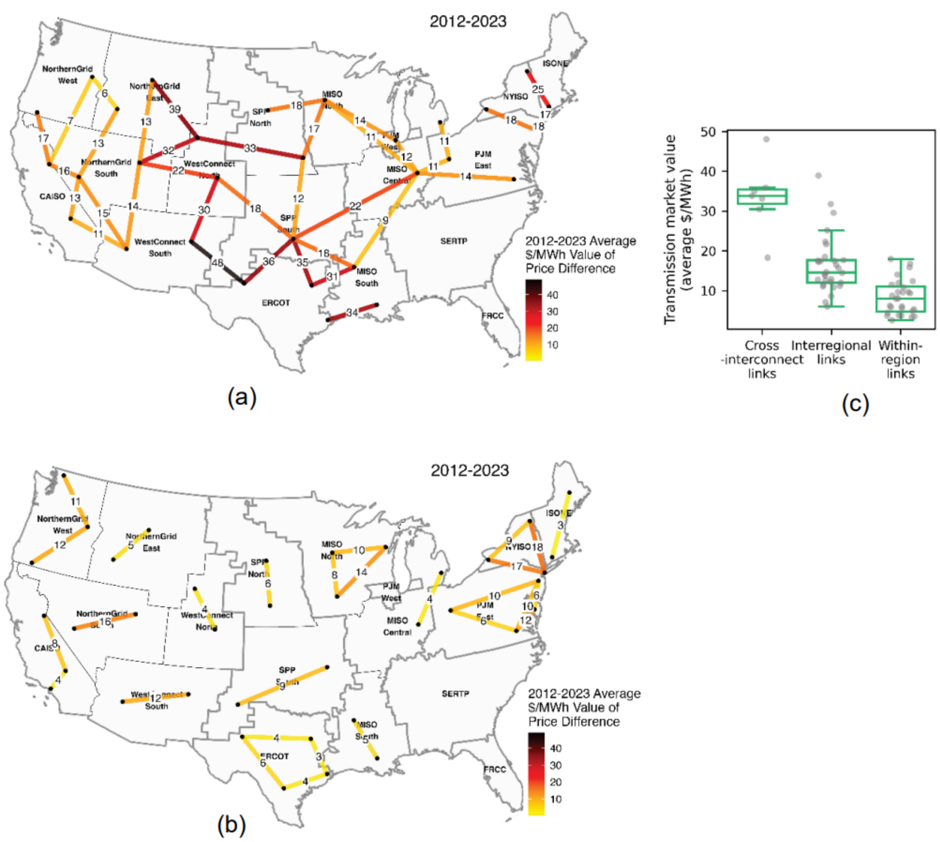
Transmission congestion occurs across all regions, with most congestion costs concentrated in 5% of hours.

Wholesale market price differentials between and within the regional transmission organizations (RTOs) and independent system operators (ISOs) (together, RTOs/ISOs) provide insight into where transmission congestion currently exists.[2] Across the U.S., transmission congestion increases the average wholesale price of electricity, with congestion costs estimated to have been $11 billion in 2023. These costs are down from a high of $21 billion in 2022, which were driven by natural gas price increases and severe weather events—such as Winter Storm Elliott in December 2022 (GridStrategies, 2024). The majority of transmission congestion costs are concentrated in 5% of the hours, particularly during times with significant day-ahead to real-time market price variance, high net load, cold weather, and high intermittent generation. While interregional transmission can enable the exchange of lower-cost electricity throughout the year, it can provide even greater value during those peak periods, which are the hours driving resource adequacy needs.

[2] Congestion is more difficult to estimate in non-RTO/ISO regions due to limited consolidated and publicly available data. The majority of the Western Interconnection along with portions of the southeastern United States are possibly underrepresented in this estimate.

Interregional and cross-interconnection linkages have the highest potential value to relieve transmission congestion and provide resource adequacy benefits.

Analysis by Lawrence Berkeley National Laboratory shows that transmission links crossing market seams between regions or interconnections have the highest potential for transmission congestion value, as indicated by the differences in locational marginal price (LMP) (Figure ES-3 (c)). Cross-interconnection links from ERCOT to neighboring regions show some of the highest LMP differentials from $31 per megawatt-hour (MWh) to $48/MWh averaged across all hours from 2012 to 2023, and links between Western Interconnection (WestConnect) and Eastern Interconnection (SPP) have LMP differentials from $18/MWh to $33/MWh (Figure ES-3 (a)). Interregional links also have high transmission congestion value, particularly between NorthernGrid and WestConnect, and between ISO-NE and NYISO (Figure ES-3 (a)). Transmission links within regions have lower LMP differentials, with the highest-value within-region links between New York City and the rest of NYISO ($17 to $18/MWh) and within NorthernGrid South ($15/MWh) (Figure ES-3 (b)).

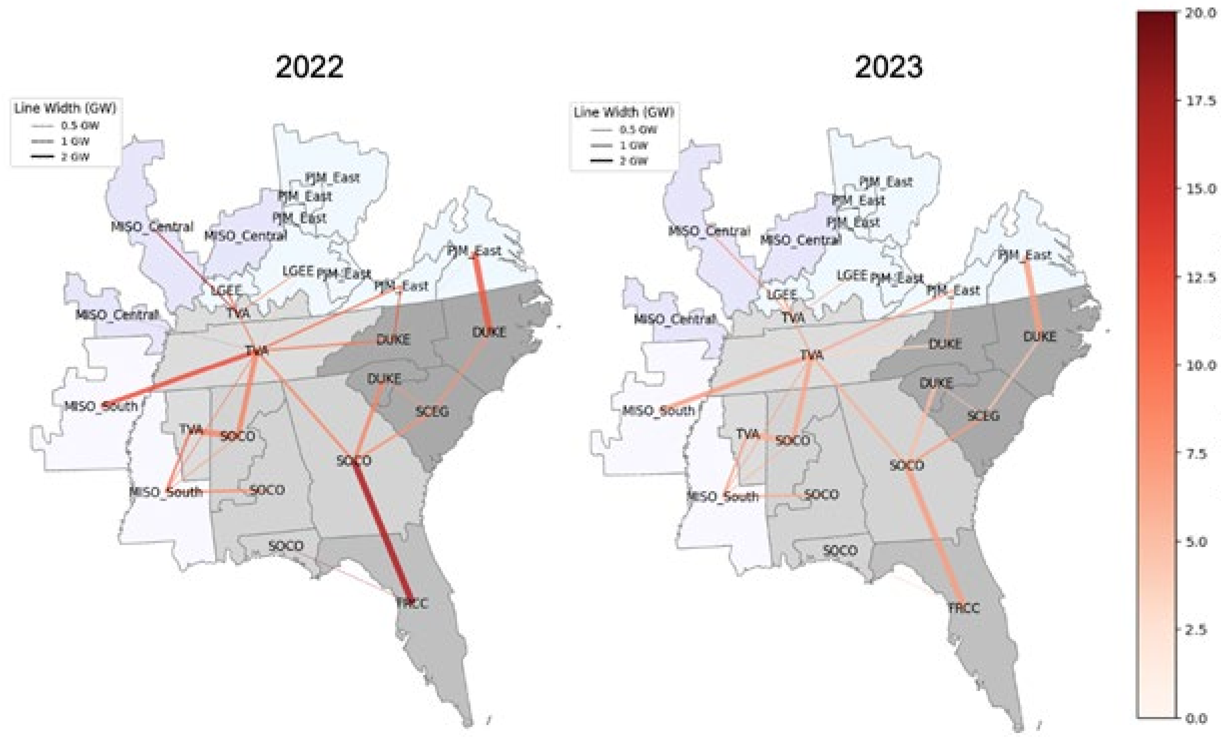


Source: Lawrence Berkeley National Laboratory (2025b).

Note: The maps of the mean marginal transmission market values for the analyzed links are divided into (a) cross-interconnect and interregional links and (b) within-region links. In some cases, the analyzed timeframe begins after 2012 (LBNL, 2025b). The graphic indicated by (c) is the distribution of mean marginal transmission market values across the set of 65 analyzed links (real-time market). Each point represents one link.

Figure ES-3. Maps of mean marginal transmission market values for all 65 analyzed links over the entire study period (real-time market) (a) and (b) and the associated distribution (c).

For the southeastern U.S., which lacks an RTO/ISO-operated energy market and publicly available LMP data, the Needs Study discusses two new approaches to provide visibility into transmission congestion in the region. Both approaches for estimating transmission congestion value from interregional links in the Southeast and Florida show similar results, with averages near $10/MWh. Results from one of the approaches are shown below in Figure ES-4, which displays transmission value by zone in the Southeast for 2022 (the highest-value year) and 2023 (a lower-value year). Building transmission that spans linkages with high transmission congestion value would have a greater impact on reducing congestion than building at other linkages. The three linkages with the highest transmission congestion value in both 2022 and 2023 are interregional links between Southern Company (SOCO)-Florida Reliability Coordinating Council (FRCC), Duke Energy-PJM, and Tennessee Valley Authority (TVA)-Midcontinent Independent System Operator (MISO) South.



Source: Lawrence Berkeley National Laboratory and National Laboratory of the Rockies (2026).

Figure ES-4. Map of transmission congestion value for interregional and intraregional links in the U.S. Southeast derived from LMP extracted from a production cost model.

In addition to reliability, RTOs/ISOs, utilities, and other planning entities are seeing future transmission needs primarily driven by load growth. To meet these needs, transmission operators are planning for substantial amounts of new regional transmission.

Recognizing the lengthy timelines associated with transmission development, the nation's transmission needs must be defined not only by current demands but also by anticipated future requirements. A literature review of regional planning efforts across the U.S. indicates that the main driver of future transmission need is load growth, which adds pressure to peak demand, driving the need for transmission investments to ensure grid reliability. Additional transmission will be needed to maintain reliability to account for generation resource changes and to address aging transmission infrastructure, resource retirements, and new generation interconnections.

Through regional planning processes, regions are investing substantially in new transmission. Some regions have recently approved their largest regional transmission planning portfolios in recent years. For example, MISO approved $21.8 billion in transmission investments, including a 765 kV transmission backbone (MISO, 2024), in the second round of long range transmission planning projects, in the Tranche 2.1 portfolio, and the Southwest Power Pool (SPP) *2024 Integrated Transmission Planning Assessment Report* identified $7.7 billion in investments, with over 2,000 new and upgraded transmission lines (SPP, 2025b), which have also been approved. Texas also recently approved its first-ever 765 kV transmission projects in the Permian Basin, a $33 billion investment.[3] Furthermore, interregional transmission is increasingly recognized for its contributions to increasing reliability, grid resilience, and meeting demand growth in at-risk areas. Several planning regions have initiated joint planning processes, such as the MISO-SPP *Joint Targeted Interconnection Queue (JTIQ) Study*,[4] to better identify interregional transmission opportunities, and more links are being developed.

Long-term, national-scale modeling studies find that significant transmission investment is needed to cost-effectively meet future demand through 2050.

To better understand the transmission needed to meet future demand, generation, and reliability requirements, DOE synthesized results from two national-scale capacity expansion modeling studies: the National Renewable Energy Laboratory's *2024 Standard Scenarios Report* (NREL, 2024b) and DOE's *National Transmission Planning Study* (DOE, 2024b), conducted by researchers at the National Laboratory of the Rockies (formerly called the National Renewable Energy Laboratory) and the Pacific Northwest National Laboratory. Both studies considered capacity expansion through 2050 for the contiguous U.S.

Long-term regional and interregional transmission needs should be identified through planning processes to make cost-effective investments that will support U.S. load growth and grid reliability.

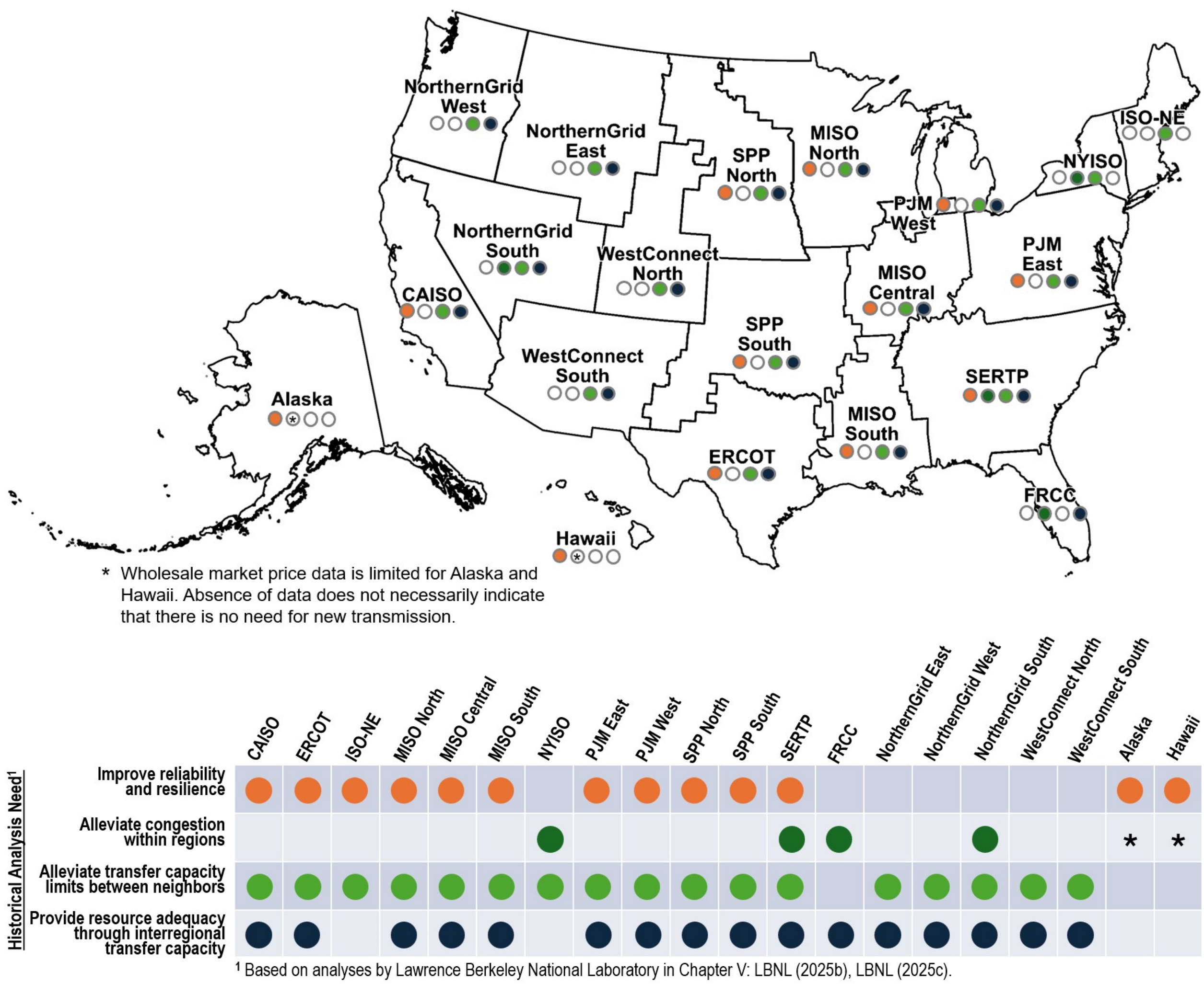
The Needs Study finds that transmission investments are needed to support load growth and reliability. New transmission facilities will also benefit consumers and grid operations by improving resource adequacy and reducing transmission congestion. New and upgraded transmission facilities are planned through processes led by regional transmission operators in collaboration with their neighboring regions. As the U.S. electric transmission system will be

[3] The Public Utility Commission of Texas's landmark decision can be found at https://www.texasre.org/pages/newsletters/may2025/article3.

[4] Information about JTIQ can be found at https://www.misoenergy.org/engage/committees/miso-spp-joint-targeted-interconnection-queue-study/.

relied on to support load growth and new generation, the assumptions and scenarios used to inform regional and interregional planning processes will be critical to ensure a reliable and secure system can be built and operated for decades to come.

Through analysis and literature review, this Needs Study identifies transmission needs throughout 20 regions of the country (Figure ES-5). Transmission needs for each region are summarized into four categories: (1) improve reliability and resilience as identified in the North American Electric Reliability Corporation's *2024 Long-Term Reliability Assessment* (NERC, 2024a), (2) alleviate congestion within regions as indicated by the analysis in Chapter V.a, (3) alleviate transfer capacity limits between neighbors as indicated by the analysis in Chapter V.a, and (4) provide resource adequacy through interregional transfer capacity as indicated by the analysis in Chapter V.c.



Source: See Supplemental Material for supporting references and methodology.

Figure ES-5. Summary of current needs identified in Needs Study by geographic region.

Acknowledgments

This work was prepared by the United States Department of Energy (DOE) Office of Electricity (OE).

DOE would like to acknowledge Lawrence Berkeley National Laboratory (LBNL) and the National Laboratory of the Rockies (NLR) for their contributions to Chapter V and Chapter VII. DOE would also like to thank LBNL for its technical review of Chapter V.

Acronyms and Abbreviations

Abbreviation	Term
AC	alternating current
AEA	Alaska Energy Authority
AI	artificial intelligence
ATC	available transfer capability
B2H	Boardman to Hemingway
BA	balancing authority
BAA	balancing authority area
BPA	Bonneville Power Administration
CAISO	California Independent System Operator
CEC	California Energy Commission
CRR	congestion revenue right
DLR	dynamic line rating
DOE	U.S. Department of Energy
DUK	Duke Energy Carolinas
Duke	Duke Energy
EEA	energy emergency alert
EIA	Energy Information Administration
EO	executive order
EPRI	Electric Power Research Institute
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
FPA	Federal Power Act
FPC	Florida Power Corporation
FPL	Florida Power & Light
FRCC	Florida Reliability Coordinating Council
GEM	Geospatial Energy Mapper
GET	grid-enhancing technology
GTC	generic transmission constraint
GW	gigawatt
GWh	gigawatt-hour
HVDC	high-voltage direct current
Hz	hertz
IIJA	Infrastructure Investment and Jobs Act
IRP	Integrated Resource Plan
ISO	independent system operator
ISO-NE	ISO New England
JTIQ	Joint Targeted Interconnection Queue
KIUC	Kaua‘i Island Utility Cooperative
kV	kilovolt
LBNL	Lawrence Berkeley National Laboratory
LMP	locational marginal price

Abbreviation	Term
LRTP	Long Range Transmission Plan
MISO	Midcontinent Independent System Operator
MVA	megavolt-amperes
MW	megawatt
MWh	megawatt-hour
NBER	National Bureau of Economic Research
PNNL	Pacific Northwest National Laboratory
Needs Study/ Needs Study Public Draft	2026 National Transmission Needs Study: Draft for Consultation and Public Comment
NERC	North American Electric Reliability Corporation
NIETC	National Interest Electric Transmission Corridor
NLR	National Laboratory of the Rockies
NPC	North Plains Connector
NREL	National Renewable Energy Laboratory
NYISO	New York Independent System Operator
OASIS	Open Access Same-Time Information System
OIE	Office of Indian Energy
PG&E	Pacific Gas and Electric
PGE	Portland General Electric
PJM	PJM Interconnection
PNM	Public Service Company of New Mexico
PSE	Puget Sound Energy
RIIA	Renewable Integration Impact Assessment
R&D	research and development
RNA	Reliability Needs Assessment
RTO	regional transmission organization
RZEP	Red Zone Transmission Expansion Plan
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric
Secretary	Secretary of Energy
SEEM	Southeastern Energy Exchange Market
SERC	SERC Reliability Corporation
SERTP	Southeastern Regional Transmission Planning
SOCO	Southern Company
SPP	Southwest Power Pool
SRP	Salt River Project
SWIP-N	Southwest Intertie Project-North
Texas RE	Texas Reliability Entity
TLR	transmission loading relief
TVA	Tennessee Valley Authority
TWh	terawatt-hour
U.S.	United States
WACM	Western Area Colorado Missouri

Abbreviation	Term
WAPA	Western Area Power Administration
WAUW	Western Area Upper Great Plains West
WECC	Western Electricity Coordinating Council
WEIM	Western Energy Imbalance Market
WEIS	Western Energy Imbalance Service
WIUFMP	Western Interconnection Unscheduled Flow Mitigation Plan
WPP	Western Power Pool

NATIONAL TRANSMISSION NEEDS STUDY

Table of Contents

Tables

Figures

I. Introduction

A robust transmission system is critical to the nation's energy dominance to support load growth and economic, energy, and national security. The United States (U.S.) Department of Energy (the Department or DOE) uses a variety of tools to address challenges in expanding and modernizing the nation's transmission infrastructure to ensure it meets both current and future needs. Within that effort, DOE is committed to the regular development of the National Transmission Needs Study (Needs Study or Needs Study Public Draft) to determine high-priority national electric transmission needs—specifically, to identify geographic areas where the bulk power grid would benefit from new, uprated, or upgraded transmission facilities.

This Needs Study will inform DOE as it coordinates the use of its authorities that relate to electric transmission. One of the underlying authorities for this Needs Study is section 216 of the Federal Power Act (FPA), which as amended directs DOE and the Federal Energy Regulatory Commission (FERC) to take specific actions aimed at accelerating electric transmission development. Section 216(a)(1) of the FPA requires DOE to perform a nationwide triennial "study of electric transmission capacity constraints and congestion," which DOE refers to as the National Transmission Needs Study or Needs Study.[5] FPA section 216(a)(2) requires the Secretary of Energy, at least once every three years, to issue a report, informed by DOE's Needs Study or other information relating to electric transmission capacity constraints and congestion, that "may designate as a national interest electric transmission corridor any geographic area that—(i) is experiencing electric energy transmission capacity constraints or congestion that adversely affects consumers; or (ii) is expected to experience such energy transmission capacity constraints or congestion" (designation report).[6]

In general, a National Interest Electric Transmission Corridor (NIETC) is a geographic area where DOE has identified present or expected transmission capacity constraints or congestion that adversely affect consumers, and which has been designated by the Secretary of Energy as a NIETC. NIETC designation enables DOE and FERC to use valuable federal financing and permitting tools to spur construction or modification of transmission facilities within a NIETC. Pursuant to FPA section 216(a)(2), DOE will consider the results of its 2026 Needs Study and other information relating to electric transmission capacity constraints and congestion when issuing any final NIETC designation reports within the statutorily mandated three-year window.

This Needs Study includes analysis of historical and anticipated electric transmission needs, an assessment of publicly available data, and more than 120 recently published reports that consider current and anticipated future transmission needs given a range of electricity demand, public policy, and market conditions. Transmission needs are defined as the existence of present or expected electric transmission capacity constraints or congestion in a geographic area. Addressing transmission needs by upgrading, uprating, or building new transmission

[5] 16 U.S.C. § 824p.
[6] *Id.*

facilities—including grid-enhancing technologies (GETs)—can improve the reliability and resilience of the power system, alleviate transmission congestion and unscheduled flows, alleviate power transfer capacity limits between neighboring regions, deliver cost-effective generation to meet demand, and/or meet projected future generation, electricity demand, or reliability requirements.

This report is being disseminated by DOE. As such, the final draft of this document will be prepared in compliance with section 515 of the Treasury and General Government Appropriations Act for Fiscal Year 2001 (Public Law 106-554) and information quality guidelines issued by the Department.

I.a. How to Use This Study

The findings of this Needs Study are intended to inform regional and interregional planning, as well as help guide the Department in the execution of its transmission-related authorities. The Department understands the factors that drive industry transmission planning today and the entities and institutions that perform such planning.[7] This Needs Study is not meant to displace these planning processes or the reliability standards they address. Rather, the Department believes it will be an important addition to overall industry and government planning efforts to reduce transmission congestion and capacity constraints that adversely affect consumers.

This Needs Study assesses the multiple drivers of current and anticipated transmission system needs within and across geographic regions, and it underscores the national commonalities of transmission needs as the power sector continues to evolve. The findings of this Needs Study also highlight the potential for additional or upgraded transmission infrastructure to address multiple power sector needs and to generate a wide range of values. The Department expects that transmission planning entities will find it useful to consider these findings to explore a wider set of transmission infrastructure benefits in their respective planning processes and consider evaluating the benefits of potential future transmission facilities together as part of proposed project portfolios rather than evaluating benefits on an incremental project-by-project basis. As demonstrated in this Needs Study, holistic, multi-value transmission planning can enable transmission solutions to meet multiple planning objectives and lead to a more efficiently planned, cost-effective transmission system.

This Needs Study also provides an assessment of anticipated transmission needs and value under various future transmission system considerations, including forecasted changes in load growth, generation mix, and anticipated generator retirements, among others. The

[7] Transmission planning is predominantly conducted today by local utilities, which plan for transmission needs on their respective transmission systems, and by regional planning authorities formed under FERC Order 1000, which plan for regional needs and identify regional transmission projects that are more efficient or cost-effective solutions. In 2024, FERC released Order 1920, which required transmission providers to produce regional long-term transmission plans on a 20-year time horizon. *See* Order No. 1000, 136 FERC ¶ 61,051 and Order No. 1920-A, 189 FERC ¶ 61,127.

Department notes transmission planning entities may use the findings of this Needs Study as a basis for conducting more granular, scenario-based transmission studies with longer planning horizons to inform more comprehensive planning assessments. Transmission planning efforts may also consider the findings to reevaluate the historical weather data used in system planning and ensure it includes the type and frequency of severe events likely to occur more regularly in the future. Further, transmission planning entities can consider if internal plans for transmission development will meet the anticipated transmission and interregional transfer capacity needs identified by national capacity expansion models summarized in this Needs Study. If future transmission plans do not match general trends in published findings of transmission need and the results of multi-scenario capacity expansion models, planning scenarios can be modified to better capture future power sector projections.

Transmission planning entities may also find this Needs Study helpful in guiding coordinated transmission planning and development efforts across systems and regions. These Needs Study findings identify the challenges and value of planning interregional transmission, as well as the geographic regions most in need of increased interregional transmission capacity. These findings can serve as a foundation for transmission planners to harmonize transmission planning processes with neighboring planning authorities and increase coordination and collaboration to develop joint transmission studies and interregional solutions.

States would also benefit from incorporating the findings contained in this Needs Study into their own regulatory and planning processes given their key role in guiding transmission planning efforts through resource procurement targets or through state-led solicitations for transmission infrastructure. They also have the ability to influence regional planning authority transmission planning decision-making through participation in stakeholder processes. Further, states and local governments could strengthen their respective transmission siting and approval processes by incorporating the findings contained in this Needs Study. As demonstrated in this Needs Study, transmission needs and potential solutions are often regional and interregional in nature and therefore do not begin or end at state boundaries, making collaboration among states critical. States can consider the regional transmission needs discussed in this study and coordinate with neighboring states to identify, plan, approve, and advocate for transmission solutions that both advance state-level policy goals and broader electricity consumer needs. Similarly, states may collaborate among themselves and with regional planning authorities and federal agencies to facilitate cost-effective interregional transmission.

I.b. Study Organization

This study is organized as follows:

Chapter II provides the legislative language under which DOE has performed this study.

Chapter III introduces the role of transmission in the power system, benefits provided by transmission, and challenges to transmission expansion. The chapter includes an overview of the physical factors and grid-reliability considerations that lead to constraints within the transmission system and clarifies the relationship between transmission constraints and congestion. It then reviews regional variations in the approaches used to manage congestion and resolve capacity constraints.

Chapter IV discusses trends in transmission investments and what they indicate about transmission infrastructure needs. The chapter reviews several metrics assessing historical transmission investment, including capital investment in new, upgraded, and rebuilt transmission and associated circuit-miles.

Chapter V reviews historical and current transmission system operations, value, and constraints, focusing on existing transmission congestion and bulk system performance during periods of greatest stress and emergency events. This chapter summarizes patterns of regional and interregional transmission congestion. It also explores how the transmission system enhances reliability and resource adequacy during peak operating periods.

Chapter VI explores anticipated future transmission needs, summarizing analyses from industry reports and regional planning documents. This chapter focuses on congestion in the U.S. electric transmission system, noting that transmission congestion is a critical issue affecting economic and operational efficiency within and between regional transmission organizations (RTOs) and independent system operators (ISOs) (together, RTOs/ISOs), as well as within and around Tribal lands, with load-weighted congestion costs varying by region.

Chapter VII reviews national-level studies that provide insights into where transmission expansion is needed to meet future electricity demand and maintain resource adequacy. This chapter explores which regional and interregional connections have the greatest need for transmission capacity expansion.

The Supplemental Materials, which can be found online,[8] contain supporting information about regional and interregional analyses that were used to support the findings in this Needs Study.

[8] Supplemental Materials and more information related to this Needs Study can be found at https://www.energy.gov/oe/national-transmission-needs-study.

II. Legislative Language

Congress has granted the Secretary of Energy (Secretary) various authorities to examine and implement programs supporting electric grid reliability and resilience. The Infrastructure Investment and Jobs Act (IIJA) directs the Secretary to establish several programs for grid infrastructure resilience and reliability, including in the following provisions: section 40101 (Preventing Outages and Enhancing Resilience of the Electric Grid); section 40103(b) (Program Upgrading Our Electric Grid and Ensuring Reliability and Resiliency); section 40106 (Transmission Facilitation Program); and section 40107 (Deployment of Technologies to Enhance Grid Flexibility). Further, section 40105 of the IIJA amended section 216 of the FPA. This Needs Study implements section 216(a)(1) of the FPA, as amended, which directs the Secretary to "conduct a study of electric transmission capacity constraints and congestion" at least once every three years.[9]

As the purpose and underlying authority of this Needs Study is broad, its scope is not constrained solely to the analytical direction set forth in section 216(a)(1) of the FPA. The Needs Study can assist the Secretary in evaluating the criteria necessary for designation of a NIETC, as provided by section 216(a).[10] Section 216(a)(2) of the FPA directs DOE to issue a report, which may designate NIETCs based on the information provided in the Needs Study or other information relating to electric transmission capacity constraints and congestion. In addition to the authorities provided in the IIJA and FPA, DOE maintains existing authorities to

[9] 16 U.S.C. § 824p(a)(1).

[10] Section 216(a)(2) gives the Secretary authority to designate a NIETC in any geographic area that: "(i) is experiencing electric energy transmission capacity constraints or congestion that adversely affects consumers; or (ii) is expected to experience such energy transmission capacity constraints or congestion" 16 U.S.C. § 824p(a)(2).

In determining whether to designate a NIETC, the Secretary may consider whether:

"(A) the economic vitality and development of the corridor, or the end markets served by the corridor, may be constrained by lack of adequate or reasonably priced electricity;

(B)(i) economic growth in the corridor, or the end markets served by the corridor, may be jeopardized by reliance on limited sources of energy; and (ii) a diversification of supply is warranted;

(C) the energy independence or energy security of the United States would be served by the designation;

(D) the designation would be in the interest of national energy policy;

(E) the designation would enhance national defense and homeland security;

(F) the designation would enhance the ability of facilities that generate or transmit firm or intermittent energy to connect to the electric grid;

(G) the designation—(i) maximizes existing rights-of-way; and (ii) avoids and minimizes, to the maximum extent practicable, and offsets to the extent appropriate and practicable, sensitive environmental areas and cultural heritage sites; and

(H) the designation would result in a reduction in the cost to purchase electric energy for consumers"

16 U.S.C. § 824p(a)(4).

perform grid-related research and development (R&D) programs, including under the Energy Policy Act of 2005, section 925 (Electric Transmission and Distribution Programs) and section 936 (R&D into Integrating Renewable Energy onto the Electric Grid); Energy Independence and Security Act of 2005, Title XIII (Smart Grid Programs); and Energy Act of 2020, sections 8001–8004 (Grid Modernization R&D Programs). DOE exercises other financing authorities that support grid infrastructure development, such as those implemented through the Office of Energy Dominance Financing (previously known as the Loan Programs Office)[11] and Transmission Infrastructure Program.[12]

Lastly, to ensure the federal government, states, and the public have access to and can obtain reliable energy information, Congress granted the Secretary authority to collect and study information as the Secretary determines necessary to help formulate energy policy.[13] This broad grant of authority is in addition to, and not in limitation of, any other authority of the Secretary.

[11] For example, under the Title 17 Innovative Energy Loan Guarantee Program and the Tribal Energy Loan Guarantee Program, the Department is authorized to provide loan guarantees to projects that will expand and improve the transmission grid. Additionally, section 1706 of the Energy Policy Act of 2005 (42 U.S.C. § 16517), as amended by section 50403 of the One Big Beautiful Bill Act (Pub. Law. No. 119-21), could also serve as a source of financing for certain transmission projects and will be administered by the Department's Loan Programs Office.

[12] The Transmission Infrastructure Program implements section 402 of the America Recovery and Reinvestment Act of 2009, which amended section 301 of the Hoover Power Plant Act of 1984. The Transmission Infrastructure Program is a federal infrastructure development assistance and financing program that manages the Western Area Power Administration's statutory $3.25 billion borrowing authority to provide debt financing and development assistance for qualifying transmission projects with at least one terminus in its 15-state service territory and that also facilitate delivery of renewable energy. More information can be found at https://www.wapa.gov/transmission/TIP/Pages/AboutTIP.aspx.

[13] *See, e.g.,* 15 U.S.C. § 772(a) and § 796; 42 U.S.C. § 7135(b).

III. Transmission Concepts

This section introduces key transmission concepts. First, it describes the role of transmission in the operation of the bulk power system and provides a brief overview of the benefits of transmission to consumers and the challenges to transmission expansion. Second, it discusses the physical factors and grid-reliability considerations that create constraints within the transmission system, which in turn can cause congestion during system operations. Finally, this section reviews regional variations in the approaches historically used to manage congestion in the Eastern Interconnection and Western Interconnection transmission systems. The congestion management practices include:

- Centralized unit commitment and economic dispatch procedures used in areas operated by RTOs/ISOs;
- Transmission service requests based on posted available transfer capability (ATC) information used in non-RTO/ISO areas;
- Transmission loading relief (TLR) used in real-time operation in both RTO/ISO and non-RTO/ISO areas; and
- The Western Interconnection Unscheduled Flow Mitigation Plan (WIUFMP) used in the non-RTO/ISO areas in the Western Interconnection.

This Needs Study does not review historical ATC and TLR data in identifying persistent congestion, except when ATC or TLR analysis was provided in the industry reports reviewed for this study. Instead, the Department uses a market price differential metric developed by FERC (2017) to identify persistent congestion.[14] ATC and TLR procedures are discussed in this section along with other congestion management schemes to provide a comprehensive view of the congestion management methods used in the U.S. power sector.

III.a. Role of Transmission in the Power Sector

The nation's transmission system facilitates the transfer of electricity from power supply sources, such as generating stations, to electrical loads where the power will be used. Transmission networks are designed to transport energy over long distances with minimal power losses, which is achieved by boosting voltages at specific points along the electricity supply chain. In the U.S., alternating current (AC) transmission lines are typically rated between 69 kilovolts (kV) and 765 kV, although exceptions can occur depending on the function of the line.[15] Lines rated 230 kV and above are generally used to deliver power across long distances, such as between states or regions. The bulk power system refers to all facilities and control

[14] Starting with ABB Velocity Suite data through 2014, FERC staff found 1,986 generator or load points in FERC-jurisdictional RTOs/ISOs where relatively high or low real-time locational marginal prices (LMPs) occurred persistently. FERC (2016) provides a discussion of congestion metrics informed by TLR data and on wholesale electricity price differentials.

[15] The North American Electric Reliability Corporation (NERC) considers transmission lines to be facilities that carry electric energy at relatively high voltages varying from 69 kV to 765 kV (NERC, 2022).

systems necessary for operating an interconnected electric energy transmission network or any portion thereof (NERC, 2025b).[16]

Transmission can refer to any facility that helps in the delivery of power from where it is generated to where it is used. Transmission lines are currently the primary means to connect remote generation sources to the locations of electricity demand. The underlying transmission network facilitates the delivery of large amounts of power from utility-scale power generation installations to consumers. Both traditional transmission infrastructure and GETs, such as advanced conductors, can be employed to improve the efficiency of the grid, improve power quality, or enable power delivery at lower costs.

Transmission infrastructure is required to connect generation resources to the larger system so that energy can be delivered to load. As more generation is developed and load continues to increase, the transmission grid will reach its limit in many places. The capacity of the grid must be expanded through the new infrastructure, rebuilds, or GETs.

Transmission infrastructure improvements provide several benefits to consumers. Transmission improves grid reliability, enables capacity to meet resource adequacy needs, and can reduce congestion costs. Increased transmission capacity also helps reduce congestion and losses, which can lead to economic benefits in the form of reduced electricity prices and reduced system costs. Relatedly, diversity in load, generation, and weather patterns within and between regions can support resource adequacy and reliability if accompanied by transmission infrastructure and a regional planning process that considers and addresses the risks and benefits of interdependence between regions. New transmission investment can help deliver the lowest cost energy resources to consumers during times when local generation costs may be higher. Many new energy resources that would help reduce power prices and meet reliability goals are currently within backlogged interconnection queues; a more efficient transmission study process can help hasten connection of those generators to the grid. In areas with high generation resource penetration, transmission buildout can reduce generation curtailment by delivering power to a wider geographic area. A more robust transmission system—along with associated upgrades to the distribution system—supports electricity demand growth and industrialization. Lastly, investing in new lines results in increased employment, tax revenues, and resilience, as well as other economic development benefits. These benefits are gained directly via new and upgraded transmission infrastructure and with upgrades to distribution and generation associated with a more robust transmission network.

Expanding transmission capacity, however, can be challenging. Navigating complex federal, state, and local processes and requirements in efforts to permit and site new lines can be difficult and result in long development periods. The problems are compounded for regional projects that cross multiple states and jurisdictions. Deciding who pays the cost of new transmission is another challenge that can delay or even derail a project. Further, quantifying the benefits of transmission is not straightforward. For cases in which project approval or allocation of project costs depends on the benefits, disputes about the size of benefits or the beneficiaries can be a significant hurdle.

[16] Refer to the glossary terms used in NERC reliability standards (NERC, 2025b).

Transmission projects also frequently face public opposition for various reasons. These challenges can lead to increased costs, schedule delays, or even project cancellations.

III.b. Transmission Needs

This study evaluates national transmission needs. For the purposes of this document, a *transmission need* is the existence of present or expected electric transmission capacity constraints or congestion in a geographic area.

Transmission congestion. *Transmission congestion*[17] refers to the economic impacts on electricity users that occur when the system must operate within its physical limits on power flow to ensure safe and reliable operation (otherwise known as a *transmission constraint*[18]). For example, power flow could be constrained by the maximum thermal limit of a transformer or power line conductor. As a result, power is rerouted through less optimal paths to deliver more expensive generation while curtailing delivery of less expensive generation to safely meet customer demand. This process occurs either manually through operator intervention or automatically via security-constrained economic dispatch.

The following bullets illustrate possible transmission system constraints that can drive congestion:

- An element of the transmission system—for example, an individual piece of equipment, such as a transformer, or a group of closely related pieces of equipment, such as the conductors that link one substation to another—that limits power flows to avoid an overload that could cause one or more elements to fail and thereby jeopardize reliability;
- An operational limit imposed on an element or group of elements to ensure that the system, as a whole, will continue to operate reliably following the failure of one or more elements; or
- A transfer limitation established to manage flows in accordance with coordination agreements.

Transmission constraints. *Transmission constraints* are limitations on the power flow across elements of the transmission system. Transmission constraints are the result of many factors, including load level, generation dispatch, and the possibility of equipment failure. Jointly, these conditions establish a specific level or limit to the permissible flow of electricity over the affected element(s) under specific operating conditions, to ensure safe and secure

[17] Energy Information Administration (EIA) defines *electricity congestion* as “a condition that occurs when insufficient transfer capacity is available to implement all of the preferred schedules for electricity transmission simultaneously” (EIA, n.d.).

[18] NERC and EIA define a transmission constraint as “a limitation on one or more transmission elements that may be reached during normal or contingency operations” (NERC, 2025b; EIA, n.d).

operations in compliance with reliability rules.[19] Transmission operating limits, which specify the maximum throughput allowable on affected transmission elements, are created to comply with these nationally established and enforced reliability rules.

The three main transmission operating limits are thermal, voltage, and stability limits.

- **Thermal limits:** Transmission equipment is designed to operate within limits that depend on the physical properties of the equipment. An electrical conductor is heated as electricity flows through that line. The thermal limit is based on the operating temperature and material properties of the conductor. Exceeding the limit can cause the line to overheat and sag excessively, posing safety problems if the line contacts vegetation or other items within or close to the right-of-way. Extreme overheating can lead to annealing, which will change the metallic properties of the line and compromise its integrity. The thermal limit ensures the line does not exceed its safe operating temperature.
- **Voltage limits:** To ensure reliability of the bulk power system, substations must operate close to their nominal voltages. Operating limits, which are set by equipment operators, specify the tolerances around the nominal levels. Voltages that are too high (overvoltages) or too low (undervoltages) can damage equipment and affect the ability to transfer power across the network. To avoid voltage violations, operators might place limits on the amount of power that can be transferred across some transmission facilities based on system conditions.
- **Stability limits:** System stability refers to the ability of the power system to return to a stable operating voltage and frequency after a momentary disturbance, such as a fault, sudden change in load, or loss of a generator. To maintain system stability, planning standards specify acceptable voltage and frequency deviation tolerances during normal operations. Frequency stability refers to the ability to maintain system frequency within tolerance during a disturbance. The U.S. bulk power system is operated at a nominal frequency level of 60 hertz (Hz). Frequency deviations can occur when the operating frequency exceeds the tolerance around 60 Hz (over or under frequency) or when voltage and current waveforms are not synchronized (phase deviations). Voltage stability is the ability to maintain voltage within an acceptable range during normal conditions and after a disturbance. Stability limits might be required to ensure that the power flow does not exceed levels that could pose a risk to system operations.

A fundamental responsibility of transmission system operators is to ensure reliable operation of the transmission system within these limits. This responsibility is executed by referring to transmission operating limits when approving or denying transmission service requests by parties seeking to use the transmission system. Operators practice congestion management to ensure both reliable operation and economic efficiencies.

[19] Reliability standards developed by NERC and approved by FERC specify how equipment or facility ratings are to be established to avoid exceeding thermal, voltage, and stability limits (NERC, 2025b).

Transmission capacity constraint. While *transmission congestion* (and the related but not identical *transmission constraint)* have industry standard definitions, *transmission capacity constraint* does not. It is defined here as a suboptimal limit of transfer of electric power on the grid. Transmission capacity constraints include limits that reduce operational reliability of the power system; power transfer capability[20] or capacity[21] limits between neighboring regions that reduce resilience or increase production costs; and limits on the ability of low-cost generation to be delivered to demand.

Transmission planning. *Transmission planning* is undertaken by transmission owners and regional planning organizations to ensure the electric grid remains reliable, efficient, and capable of meeting evolving energy demands. These planning efforts—at both local and regional levels—are generally governed by regulations established by FERC, which set forth minimum standards and required inputs to guide the planning process. Within the FERC Order No. 1000 Transmission Planning Regions, as well as in the Electric Reliability Council of Texas (ERCOT), transmission planning processes typically involve comprehensive assessments of regional reliability, public policy objectives, and economic considerations to identify future transmission infrastructure needs (CAISO, 2024b; ERCOT, 2024d; FRCC, 2024; ISO-NE, 2025a; MISO, 2024; NorthernGrid, 2020; NYISO, 2026; PJM, 2023a; PJM, 2023b; SPP, 2016; SERTP, 2024; WestConnect, 2021).

Transmission planning processes are evolving to become more integrated and adaptive, enabling a coordinated evaluation of reliability, economic needs, and public policy. Instead of addressing these needs in isolation, planners assess them sequentially while maintaining the flexibility to revisit earlier decisions if later alternatives offer broader benefits or greater cost-effectiveness (CAISO, 2024b; SPP, 2025b).

In 2024, FERC issued Order No. 1920,[22] which requires transmission providers to conduct long-term regional transmission planning every five years with a planning horizon of no less than 20 years. This long-term transmission planning must be done by developing a set of scenarios, with input from relevant state entities. The transmission provider then must evaluate whether new transmission facilities would cost-effectively address long-term transmission need. Order No. 1920 outlines seven transmission benefits that may be used by transmission providers, including (1) avoided or deferred reliability transmission facilities, (2) reduced loss of load probability or reduced planning reserve, (3) production cost savings, (4) reduced transmission energy loss, (5) reduced congestion, (6) mitigation of severe weather events, and (7) capacity cost benefits from reduced peak energy losses. As described in Order No. 1920, transmission

[20] Transfer capability is defined in NERC (2025b) as "The measure of the ability of interconnected electric systems to move or transfer power *in a reliable manner* from one area to another over all transmission lines (or paths) between those areas under specified system conditions."

[21] Transfer capacity does not have an industry standard definition but commonly refers to the ability of a transmission line to transfer power without causing facility overloads under contingency and is calculated considering the electrical and physical parameters of the line given the normal ambient conditions in its location.

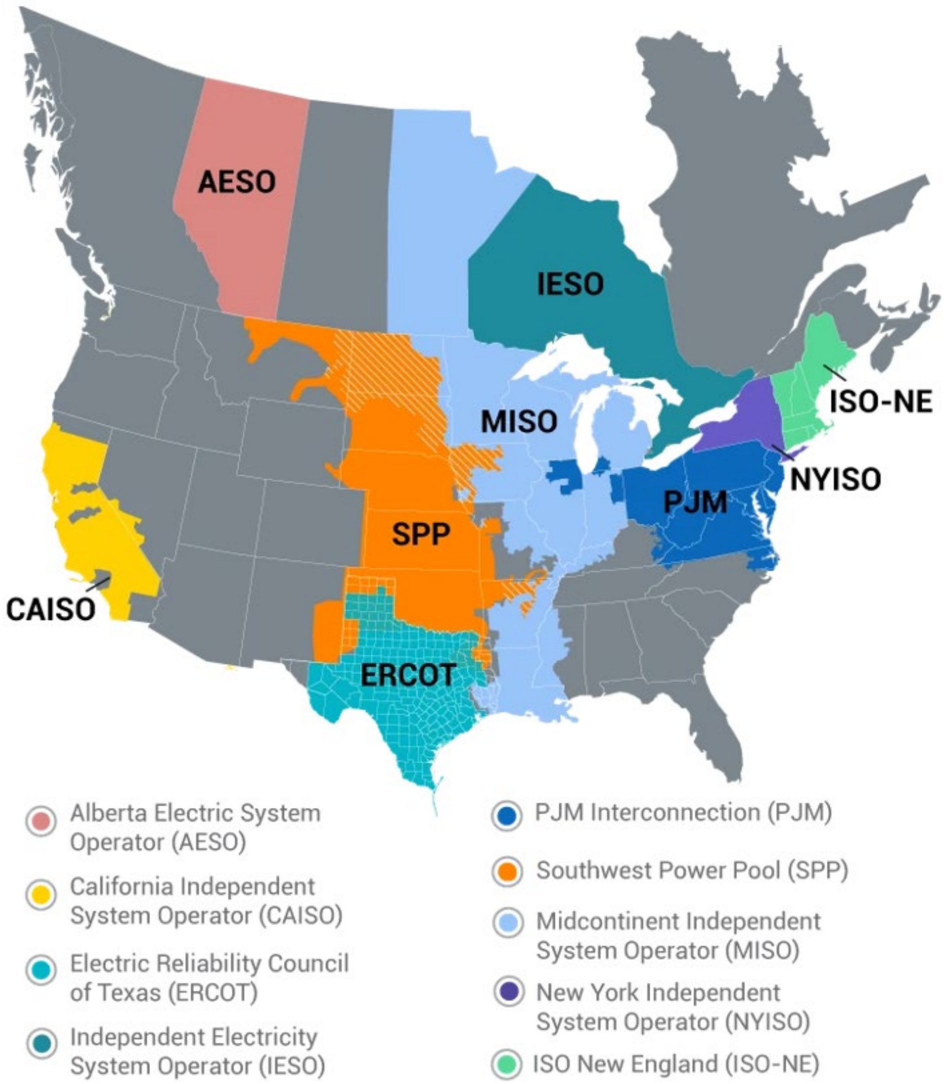
[22] *See* Order No. 1920-A, 189 FERC ¶ 61,127.

providers must also develop default cost allocation methods for long-term transmission development that will distribute costs for long-term regional transmission facilities in a manner roughly commensurate to how benefits are accrued from those facilities.

Interregional coordination is another key component of transmission planning, allowing neighboring regions to collaboratively identify and implement transmission solutions that are more efficient, cost-effective, and resilient than isolated regional efforts. This process typically involves data sharing, joint modeling, and collaborative studies. For example, in the Western Interconnection, planning regions such as California Independent System Operator (CAISO), WestConnect, and NorthernGrid participate in a biennial review process to evaluate interregional transmission proposals and allocate costs according to shared benefits (CAISO, 2024b; NorthernGrid, 2020; WestConnect, 2021). In the Midwest and central U.S., the Midcontinent Independent System Operator (MISO) and Southwest Power Pool (SPP) coordinate through initiatives like the Joint Targeted Interconnection Queue (JTIQ), which facilitates the integration of generation resources along their shared seam (MISO, 2024). MISO also partners with PJM Interconnection (PJM) and engages more informally with the Southeastern Regional Transmission Planning (SERTP), conducting joint studies that consider reliability, economic impacts, public policy objectives, and severe weather scenarios. Similarly, the New York Independent System Operator (NYISO) and SERTP work with their neighboring systems to align reliability assessments and explore interregional solutions that may outperform regional or local alternatives (NYISO, 2026; SERTP, 2024). For example, NYISO, ISO New England (ISO-NE), and PJM form the Interregional Planning Stakeholder Advisory Committee. Following the release of FERC Order No. 1920, transmission providers must align their existing transmission coordination processes with the long-term planning processes outlined in Order No. 1920. Under Order No. 1920, transmission providers will need to collaboratively share information about transmission needs and jointly evaluate interregional transmission solutions. These collaborative efforts reflect a growing recognition that effective transmission planning must transcend regional boundaries to ensure a reliable, efficient, and future-ready grid.

III.c. Transmission Regions

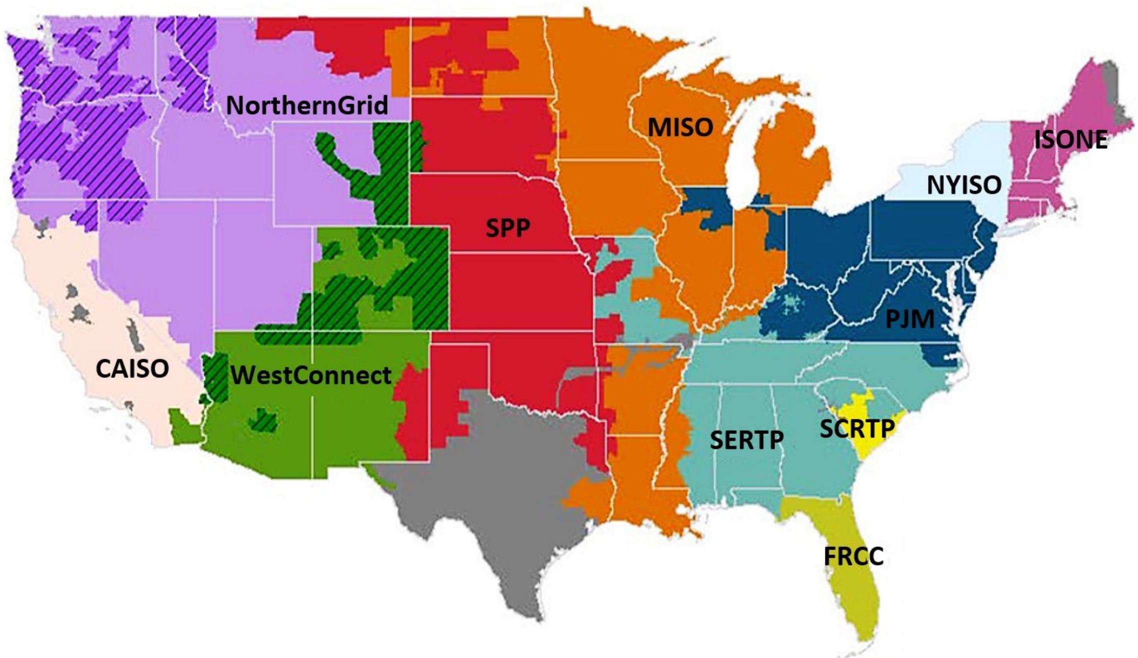
Several different entities are responsible for regional transmission planning, transmission system operations, and reliability. The RTOs/ISOs operate and facilitate wholesale markets to connect generators and load-serving entities across their respective transmission systems. Seven RTOs/ISOs in the U.S. and two RTOs/ISOs in Canada operate on the North American power grid (Figure III-1).



Source: ISO/RTO Council (IRC, n.d.).

Figure III-1. RTO/ISO footprints.

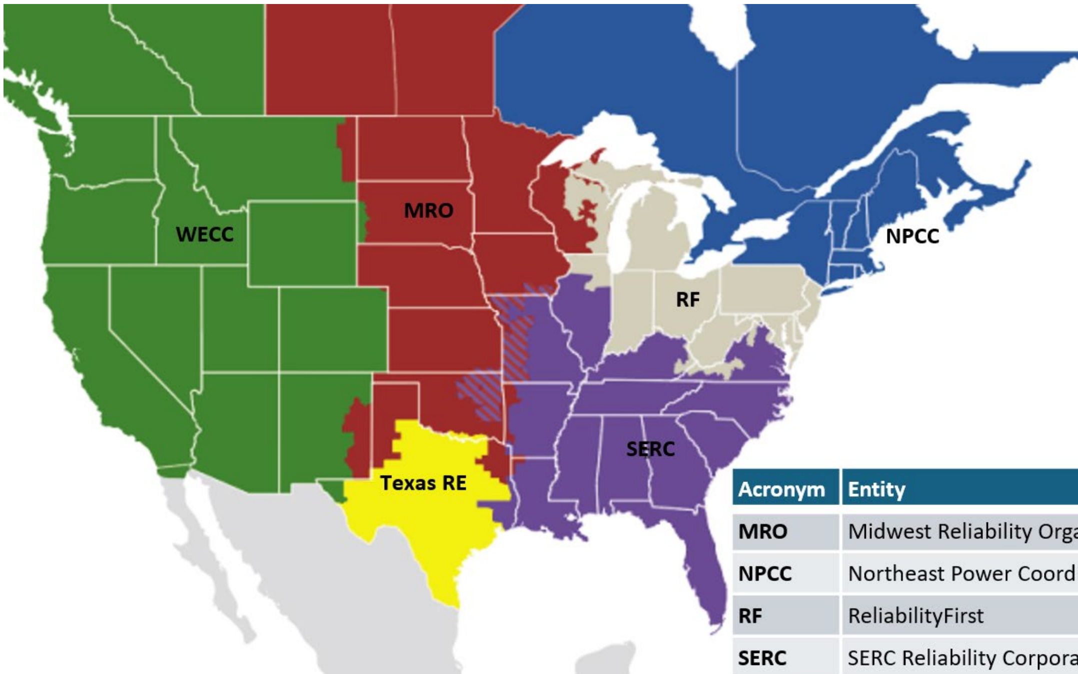
Regional transmission planning occurs within the FERC Order No. 1000 Transmission Planning Regions (Order 1000 regions) and ERCOT (collectively, transmission planning entities) (Figure III-2). The seven U.S. RTOs/ISOs serve as Order 1000 regions in their territories.



Source: Federal Energy Regulatory Commission (2024).
Note: This image was formatted to improve legibility.

Figure III-2. FERC Order No. 1000 transmission planning regions.

Six regional reliability entities oversee the development and implementation of mandatory national and regional reliability standards within the North American bulk power system (Figure III-3). Similarly, the RTOs/ISOs often serve this reliability coordination function in conjunction with their associated reliability entity.



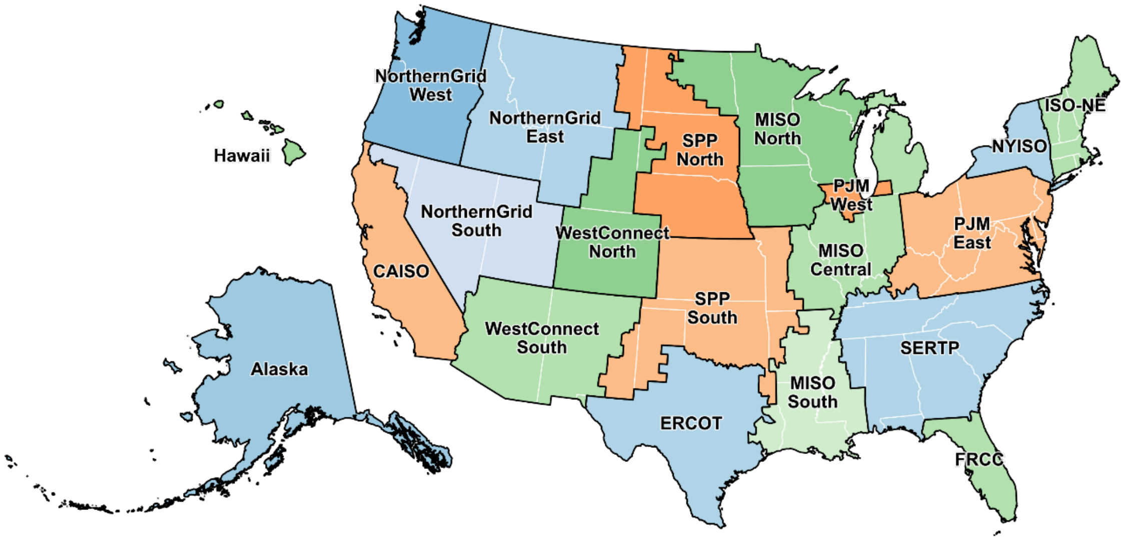
Acronym	Entity
MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordination Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council

Source: North American Electric Reliability Corporation (2024a).
Note: This image was formatted to improve legibility.

Figure III-3. Regional reliability entities.

This study organizes transmission need results by 20 transmission planning subregions ("Needs Study regions"), to the extent possible. Figure III-4 displays the Needs Study regions used in this analysis. If data sources are specific to an RTO/ISO, Order 1000 region, or regional reliability entity, the appropriate power system entity name may also be used. Table III-1 identifies the transmission planning subregion nomenclature used in this study and the principal power system entity associated with that geographic area for completeness.

DOE acknowledges there are industry planning or interregional coordination naming conventions that are centered around the FERC Order 1000 regions. As such, where DOE uses the terminology "interregional," "intraregional," or "within-region" transmission infrastructure or needs in this study, DOE clearly identifies which sections of the report contain findings that point to transmission infrastructure or needs that extend specifically between the 20 Needs Study regions displayed in Figure III-4 below.



Note: Geographic boundaries that align with the transmission planning subregions (regions) are used whenever possible.

Figure III-4. Transmission planning subregions used to present study results in this analysis, where appropriate.

Table III-1. Region names used throughout this report. The dominant power system entities that serve transmission planning, transmission system operations, and reliability functions in each geographic region are also presented.

Transmission Planning Subregion	FERC Order 1000 Region	RTO/ISO	Reliability Entity
CAISO	California Independent System Operator	California Independent System Operator	Western Electricity Coordinating Council
NorthernGrid West	Northern Grid	–	Western Electricity Coordinating Council
NorthernGrid East	Northern Grid	–	Western Electricity Coordinating Council
NorthernGrid South	Northern Grid	–	Western Electricity Coordinating Council
WestConnect North	WestConnect	–	Western Electricity Coordinating Council
WestConnect South	WestConnect	–	Western Electricity Coordinating Council
ERCOT	–	Electric Reliability Council of Texas	Texas Reliability Entity
SPP North	Southwest Power Pool	Southwest Power Pool	Midwest Reliability Organization

Transmission Planning Subregion	FERC Order 1000 Region	RTO/ISO	Reliability Entity
SPP South	Southwest Power Pool	Southwest Power Pool	Midwest Reliability Organization
MISO North	Midcontinent Independent System Operator	Midcontinent Independent System Operator	Midwest Reliability Organization; Reliability First
MISO Central	Midcontinent Independent System Operator	Midcontinent Independent System Operator	Midwest Reliability Organization; SERC Reliability Corporation; Reliability First
MISO South	Midcontinent Independent System Operator	Midcontinent Independent System Operator	SERC Reliability Corporation
SERTP	Southeastern Regional Transmission Planning & South Carolina Regional Transmission Planning	–	SERC Reliability Corporation
FRCC	Florida Reliability Coordinating Council	–	SERC Reliability Corporation
PJM East	PJM	PJM	Reliability First; SERC Reliability Corporation
PJM West	PJM	PJM	Reliability First
NYISO	New York Independent System Operator	New York Independent System Operator	Northeast Power Coordinating Council
ISO-NE	ISO New England	ISO New England	Northeast Power Coordinating Council
Alaska[a]	–	–	–
Hawaii[b]	–	–	–

[a] According to the U.S. Environmental Protection Agency (EPA), the North American Electric Reliability Corporation (NERC) region Alaska Systems Coordinating Council (ASCC) in Alaska is no longer used. As such, this report will be using the name of the state as the transmission planning subregion. This information can be found at https://www.epa.gov/egrid/frequent-questions-about-egrid.

[b] According to the EPA, the NERC region Hawaii Interconnection Coordinating Council (HICC) in Hawaii is no longer used. As such, this report will be using the name of the state as the transmission planning subregion. This information can be found at https://www.epa.gov/egrid/frequent-questions-about-egrid.

Source: Transmission planning entities from Federal Energy Regulatory Commission at https://www.ferc.gov/media/regions-map-printable-version-order-no-1000 and reliability entity names from North American Electric Reliability Corporation Long-Term Reliability Assessment (NERC, 2024a).

III.d. Regional Practices for Managing Congestion

FERC Order Nos. 888 and 889 promulgated rules for the use of the U.S. portions of the transmission systems in the Eastern and Western Interconnections. The orders sought to ensure nondiscriminatory access to the transmission system. RTOs/ISOs use market-based approaches for allocating ATC according to users expressed willingness to pay for transmission services. Non-RTO/ISO transmission system providers use administrative approaches to allocate transmission capacity, announcing the availability of transmission service and accepting requests for such service on a nondiscriminatory basis. Both RTO/ISO and non-RTO/ISO transmission providers also rely on specialized procedures for managing the operations of the transmission system in real time.

RTO/ISO Congestion Management Practices

RTOs/ISOs use centralized unit commitment and economic dispatch procedures driven by competitive offers from generators to sell electricity to purchasers. These procedures account for all transmission constraints to form a marginal price at each point within the transmission system, that is, the point at which wholesale electricity is either injected into the system by a seller or withdrawn by a purchaser. When no transmission or generation constraints are restricting economic dispatch and all desirable transactions are occurring, all the marginal prices at all points will be identical, apart from the effect of transmission losses. If a constraint is present, the marginal prices on the two sides of the constraint will differ. The difference in price is an economic measure of the congestion cost.

If a transmission investment removes a transmission constraint to relieve congestion, the investment will reduce congestion costs. Reducing load or increasing generation on the load side of a constraint will have a similar effect in reducing congestion costs. The congestion costs avoided are a direct measure of the economic benefit from, or value of, this investment. In actual cases, these benefits, intrinsically, might or might not be sufficiently large and recurrent to warrant the investment. Reducing congestion costs is not the only economic benefit (or non-economic benefit) that might justify a transmission investment, as discussed later in this study.

Non-RTO/ISO Congestion Management Practices

Transmission system operators that are not part of an RTO/ISO publicly post the ATC on their Open Access Same-Time Information Systems (OASIS) web pages in advance of real-time operations. These operators then receive, review, and either accept or deny users' requests for transmission service on a firm or non-firm basis at established rates.

ATC directly reflects how close operation is to a transmission constraint. An ATC value of zero means no further requests for transmission services can be accepted, because no additional flows of electricity can be accommodated without violating a reliability limit.

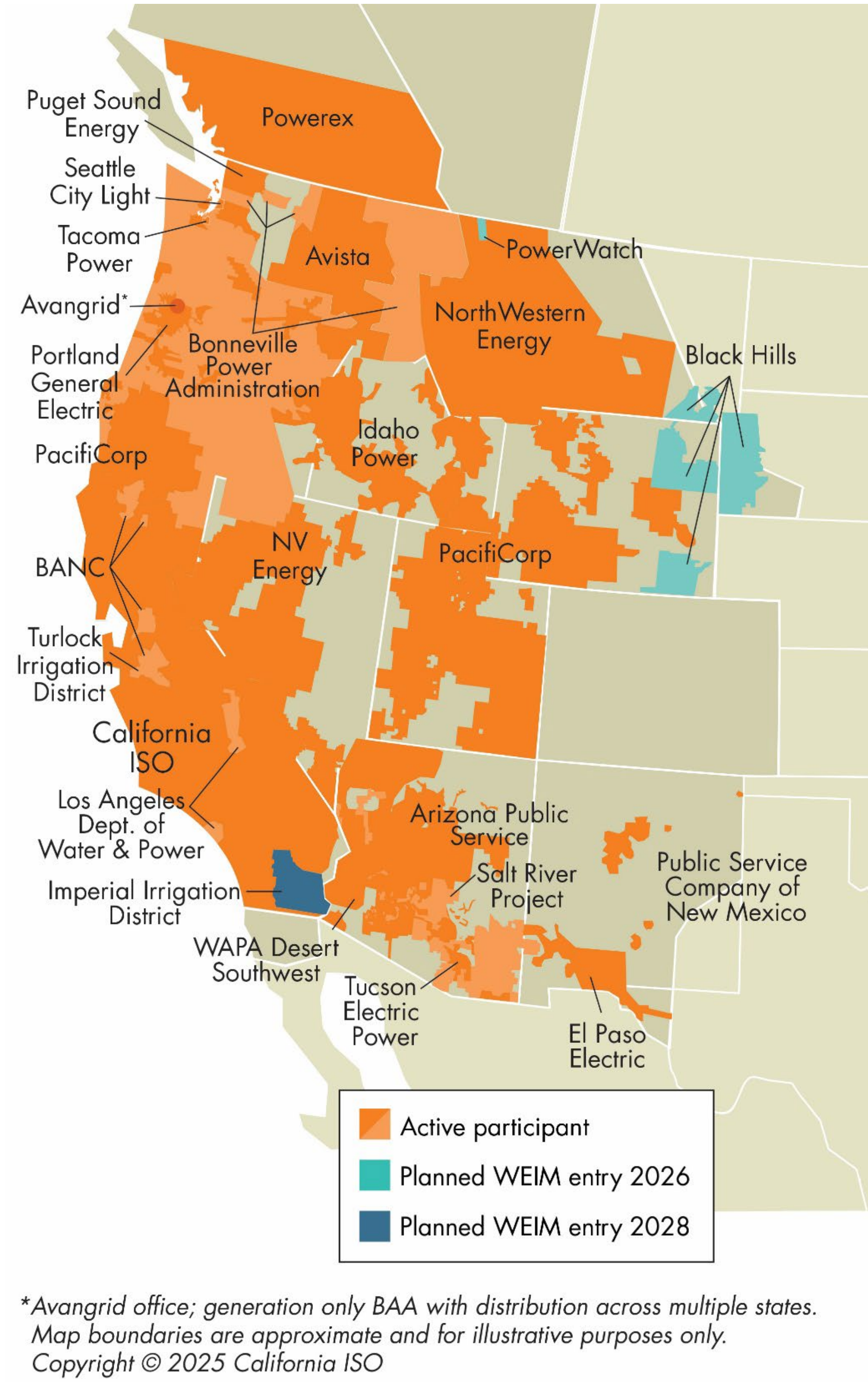
Denials of requests for transmission service provide a direct, but incomplete, measure of congestion. Denials are a direct measure because they reflect a desire to use the transmission system that was foregone because of one or more transmission constraints. But denials do not provide information on the economic significance of the congestion they represent and no information on the value of transmission or other efforts to relieve the constraints that underlie this congestion. Information on denials of requests for transmission service is also an incomplete measure because it does not capture requests that were not made because of users' perceptions of the availability of services. Potential users seeking those services might forgo requesting them at times of limited availability, in part because of experience of requests being denied under these conditions. An additional reason a desired service might not be requested is that the ATC had already been set to zero.

Non-RTO/ISO regions have several options to manage congestion through market procedures. In particular, RTO/ISO economic dispatch procedures that serve, in part, to manage congestion in real time can be used by non-RTO/ISO regions through energy imbalance markets, day-ahead markets, and expanded RTO markets or services (Energy Strategies, 2021a). Congestion management capabilities increase with each level of market:

- Real-time energy imbalance markets aid real-time congestion management.
- Developing day-ahead markets will further support transmission optimization and congestion management with the addition of day-ahead unit commitment.
- Expanding RTO/ISO markets to non-RTO/ISO regions will provide the most holistic mechanisms to support reliability via both congestion management and increased coordination in transmission planning.

There are three active energy imbalance markets in the U.S.: Western Energy Imbalance Market (WEIM), Western Energy Imbalance Service (WEIS), and Southeastern Energy Exchange Market (SEEM).

In 2014, CAISO launched WEIM, a real-time energy market that extended the market-based approach for congestion management in the real-time market beyond CAISO's footprint. By 2023, WEIM had expanded to include market participants in all or parts of each state in the Western Interconnection except Colorado and the portions of South Dakota and Nebraska located in the Western Interconnection (*see* Figure III-5).

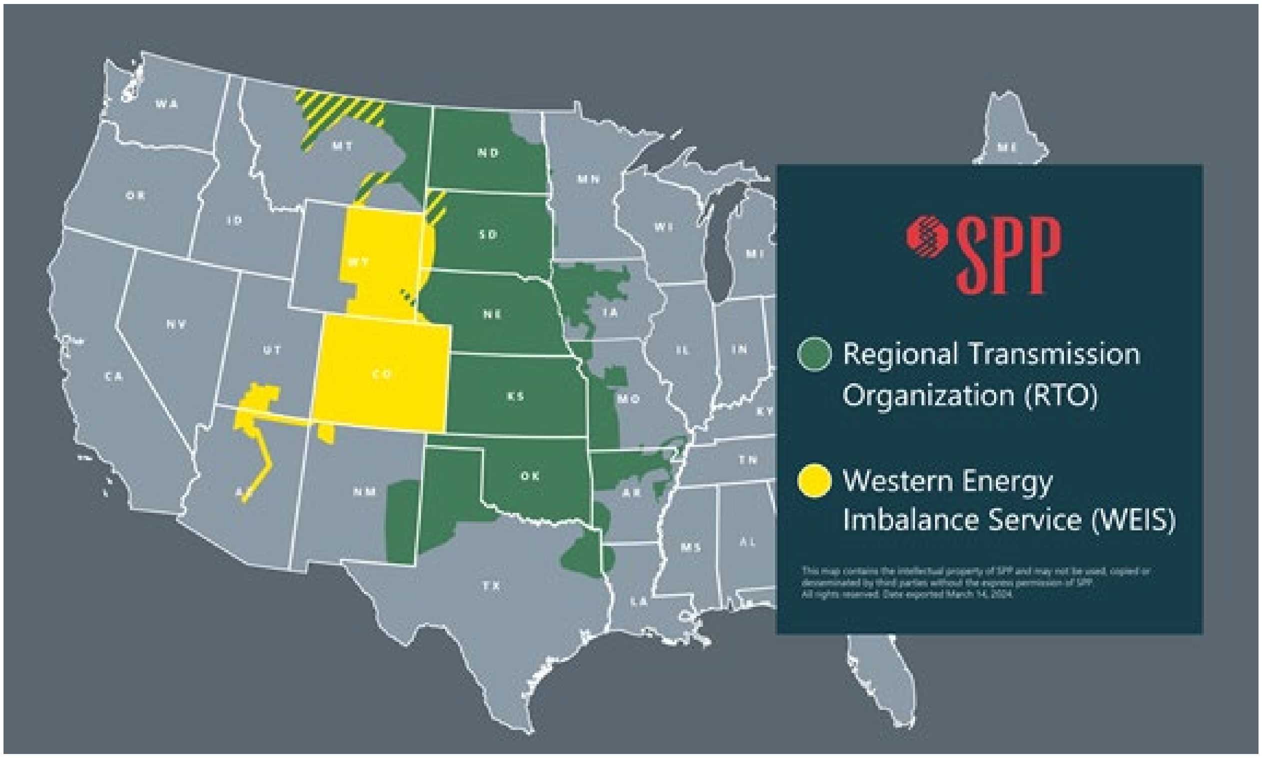


Source: Western Energy Markets (n.d.).

Figure III-5. Western Energy Imbalance Market footprint.

In 2021, the SPP launched the WEIS for utilities in the Western Interconnection. The footprint encompasses all or parts of Arizona, Colorado, Montana, New Mexico, and Wyoming and includes the Western Area Power Administration (WAPA) Western Area Upper Great Plains West (WAUW) and Western Area Colorado Missouri (WACM) balancing authority areas

(BAAs) along with the Public Service Company of Colorado BAA (Figure III-6). In 2024, the WEIS was used to redispatch generation to mitigate congestion on 46 unique system constraints, providing relief for more than 9,000 time intervals, or 8.6% of the total intervals for the year.[23]



Source: Southwest Power Pool (n.d.).

Figure III-6. Southwest Power Pool Western Energy Imbalance Service footprint.

In November 2022, utilities in the Southeast launched the SEEM to trade energy in real time,[24] an extension of the bilateral contracts currently used in that region. Despite these developments, however, information on the economic value of congestion outside RTOs/ISOs is minimal when compared with the market price differential data available from RTOs/ISOs and reviewed in this study.

Currently, both CAISO and SPP are in the process of implementing day-ahead markets for entities outside the RTO footprints.[25,26] These markets are expected to combine the benefits of the real-time energy imbalance market congestion management currently in place with day-

[23] Data provided by SPP WEIS operations staff, pulled from the 2024 Annual Violation Relaxation Limit Analysis, can be found at https://spp.org/documents/72101/vrl%202024%20analysis%20weis.pdf.

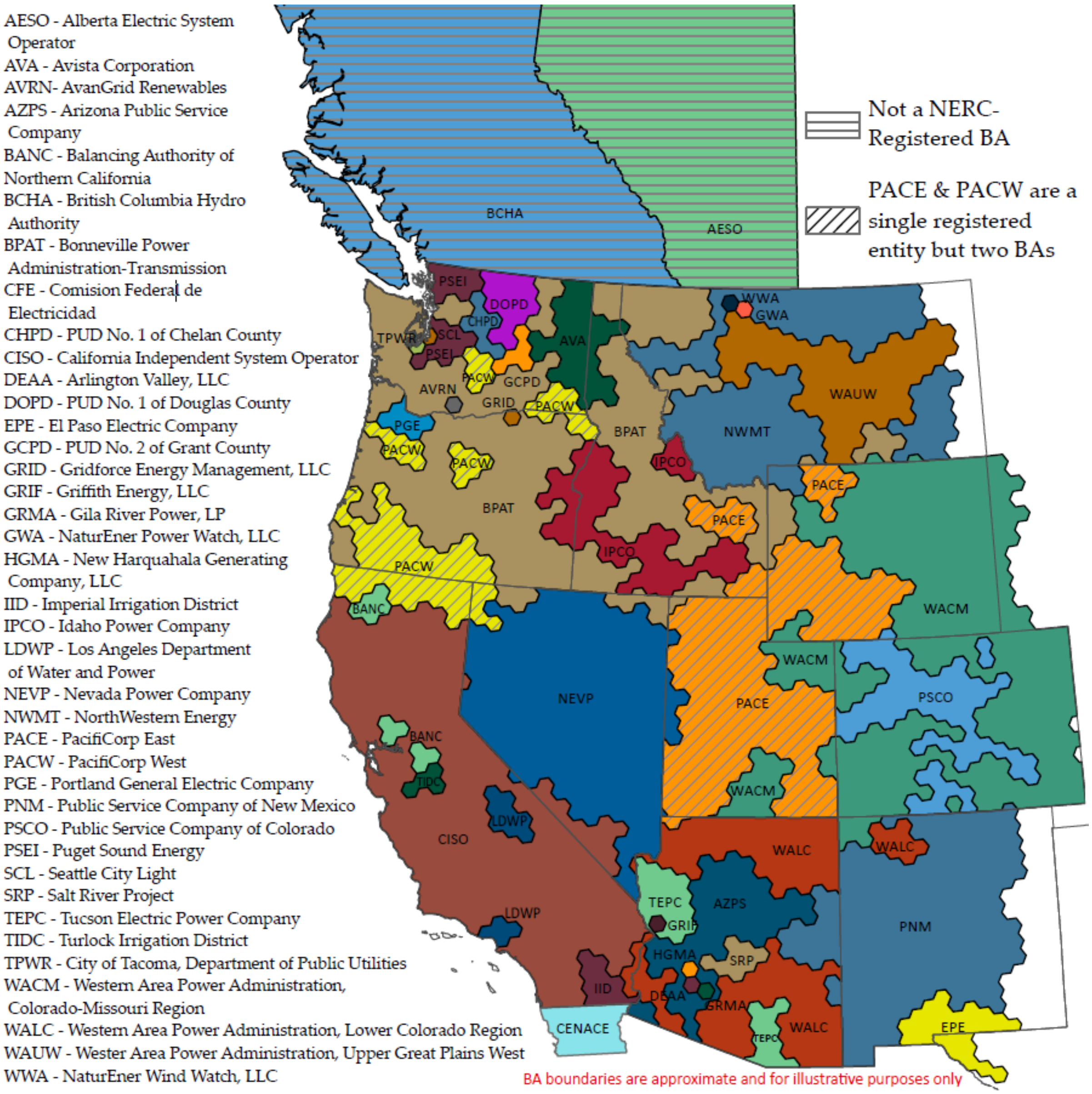
[24] For more details, *see* "FERC Accepts Southeast Energy Exchange Market [SEEM] Settlement" at https://southeastenergymarket.com/.

[25] For more details, *see* "Extended Day-Ahead Market (EDAM)" at https://www.westerneim.com/Pages/ExtendedDayAheadMarket.aspx.

[26] For more details, *see* "What is Markets+?" at https://www.marketsplus.org/about.

ahead unit commitment to further optimize transmission system utilization and better support reliability.

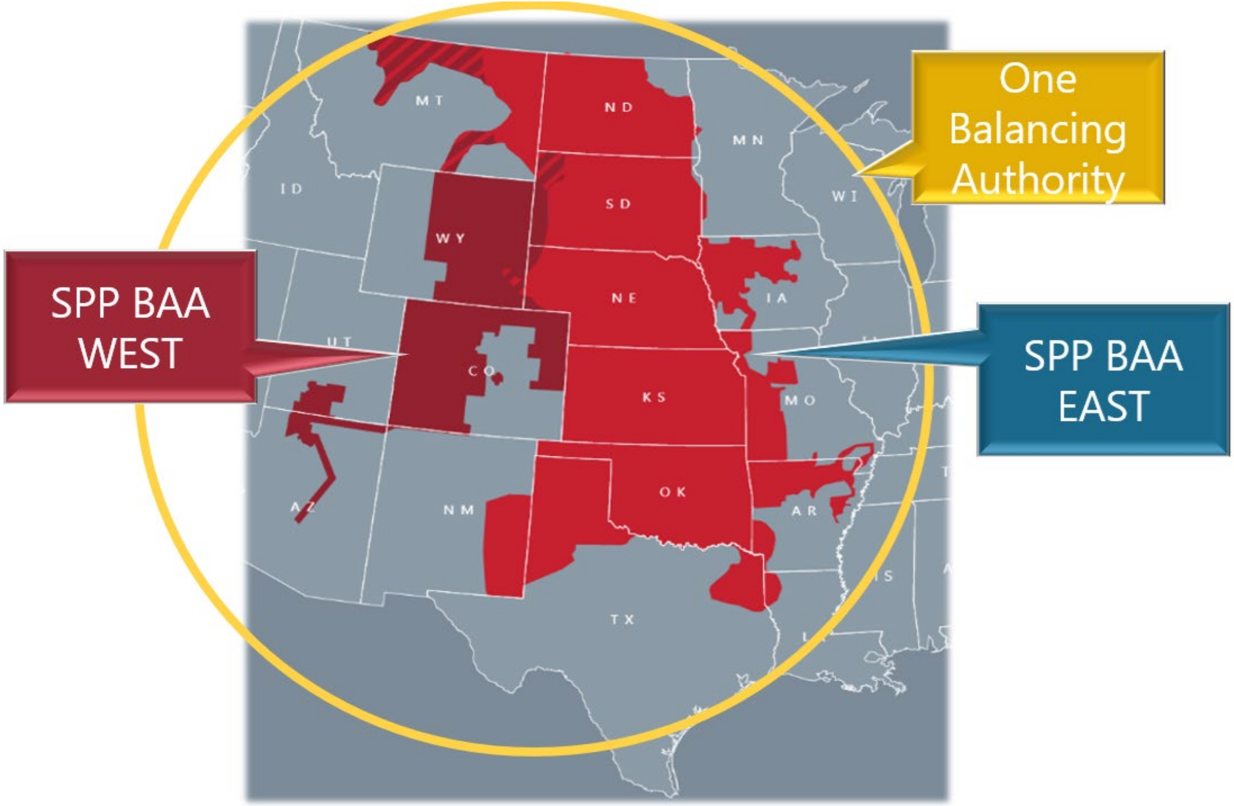
Like the real-time energy imbalance markets, the day-ahead markets will be on a balancing authority (BA) by BA basis. The BAAs in the Western Interconnection are shown in Figure III-7. With the real-time energy imbalance and day-ahead markets, the existing structure with over 34 BAs in the Western Interconnection will remain, as will the current individual transmission planning and Order 1000 processes.



Source: Western Electricity Coordinating Council Maps of the Western Interconnection, at https://www.wecc.org/maps-of-the-western-interconnection.

Figure III-7. Western Electricity Coordinating Council balancing authorities.

In parallel with the development of the CAISO and SPP day-ahead markets, SPP RTO expansion efforts are underway. SPP and WAPA's Colorado River Storage Project, Rocky Mountain, and Upper Great Plains Regions, along with six additional entities, are in the process of integrating into the SPP RTO (Figure III-8). With the expansion of the SPP RTO into the Western Interconnection, WAPA's WACM and WAUW BAAs, along with approximately 27 embedded entities, will transition to SPP's centralized transmission planning [27] processes and RTO congestion management.[28]



Source: This map is the intellectual property of SPP and is used with permission.

Figure III-8. Southwest Power Pool balancing authority and balancing authority areas after expansion in the Western Interconnection.

Specialized Congestion Management Practices Used in Real-time Operations

Transmission system operators of both types (i.e., RTO/ISO and non-RTO/ISO) also rely on specialized procedures for managing congestion during real-time operations. These procedures are necessary to ensure reliable operation of the power system when unforeseen

[27] More information on SPP's transmission planning processes can be found at https://www.spp.org/engineering/transmission-planning/integrated-transmission-planning/ and https://www.spp.org/engineering/consolidated-planning-process/.

[28] The SPP Tariff and Governing Document revisions to enable the expansion of the SPP RTO into the Western Interconnection were approved by FERC on March 20, 2025 (*see* https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20250320-3063&optimized=false) and the target go-live date in the West is April 1, 2026.

events occur that alter the capabilities of the transmission system from those that were assumed when the requests for transmission service were made (e.g., unexpected outage of a transmission facility), or when conflicts arise among the services agreed upon by different transmission system operators.

Transmission Loading Relief Administrative Procedures

In the Eastern Interconnection, principally but not exclusively in the southeastern regions served by non-RTOs/ISOs, transmission system operators use the TLR[29] administrative procedure to address congestion that arises in real time.[30] Five levels of TLR procedures can be invoked. TLR Level 3 is the lowest level that involves curtailments of transmission service to ensure that constrained transmission facilities are not loaded beyond safe reliability operating limits. TLR Level 5 is the most severe level; it involves reducing the levels of firm transmission service. Information on TLRs is posted publicly by the North American Electric Reliability Corporation (NERC).[31]

TLRs of Level 3 and above involve curtailments of, or reductions to, previously agreed-upon transmission services. TLRs are a direct measure of transmission congestion because the measurement represents transmission services that must be foregone because of a transmission constraint. They are not economic measures of congestion because, like denials of requested transmission service, they provide no information on the value of the transmission services that have been foregone. They also do not provide insight into expected future congestion.

The Western Interconnection Unscheduled Flow Mitigation Plan

The WIUFMP was developed to manage congestion and loop flows in the Western Interconnection (SPP, 2019).[32] Because of the topology of the transmission system in the West, transactions from the Northwest to California result in unscheduled energy (loop) flows into Wyoming, Colorado, New Mexico, and Arizona. Under the mitigation plan, stakeholders have identified "Qualified Paths" where congestion is significant enough to pose a reliability risk. To be included as a Qualified Path, a transmission path must have operated at or near its rated capacity for a minimum of 100 hours over the past 36 months, along with curtailments to manage the flow on the path. The path could also be susceptible to unscheduled flows. The

[29] RTOs/ISOs in the Eastern Interconnection principally use price to manage congestion, and rarely invoke TLR, when compared with the non-RTO/ISO regions.

[30] In the Western Interconnection, the real-time administrative counterpart to the TLRs used in the Eastern Interconnection is called "unscheduled flow mitigation." Unlike in the Eastern Interconnection, information on unscheduled flow mitigation in the Western Interconnection is not posted publicly.

[31] The "Transmission Loading Relief (TLR) Procedure" for the Eastern Interconnection can be found at https://www.nerc.com/globalassets/standards/reliability-standards/iro/iro-006-east-2.pdf.

[32] Revision 4 of the WIUFMP was filed with FERC by PacifiCorp on August 9, 2019, in Docket No. ER19-2566 (SPP, 2019). The revised plan was accepted by FERC on October 9, 2019. The mitigation plan is administered by SPP and can be found in FERC's Docket eLibrary at https://elibrary.ferc.gov/.

WIUFMP manages congestion on the Qualified Paths using designated Qualified Controllable Devices and using curtailment when necessary. Qualified controllable devices are selected depending on their effectiveness in reducing unscheduled flows on the Qualified Paths. *See* Chapter V.b for further discussion of WIUFMP.

IV. Historical Transmission Investment

Transmission development across the U.S. is driven by the need to maintain electricity reliability, replace aging infrastructure, reduce transmission congestion, and support future new generation, load growth, and public policy needs. This chapter reviews the development of new, upgraded, and rebuilt transmission in the U.S. between 2016 and 2024 and describes the magnitude, trends, and drivers of transmission development. Capital costs and circuit-miles of new transmission are used as the primary metrics to evaluate the pace and magnitude of transmission development in the U.S., in line with the metrics used by FERC (2017) to assess historical transmission investment. Key findings from this analysis include:

- From 2016 to 2024, significant investments have been made to enhance the reliability, capacity, and resilience of the transmission system. Throughout all regions in the U.S., 85,000 circuit-miles of newly constructed, upgraded, or rebuilt transmission lines rated at or above 69 kV have been built.[33]
- Transmission investment varies considerably by region. Between 2016 and 2024, ERCOT and MISO North energized 6.2 and 5.1 circuit-miles per terawatt-hour (TWh) of annual load, respectively, while Hawaii, NorthernGrid South, NorthernGrid West, PJM West, and SERTP built less than 1.2 circuit-miles per TWh of annual load. Capital investment costs also vary by region, with the highest expenditures in PJM East and ERCOT at $3.5 billion and $2.1 billion per year, respectively, on average across the nine-year analysis period.
- The majority (66%) of new circuit-miles are 69 or 138 kV, with only 4% of new circuit-miles at 500 kV or above.
- Incumbent utilities developed 98% of all new transmission, with 11 out of 21 Needs Study regions having 100% incumbent utility development. Some regions had higher levels of non-incumbent utility development, including WestConnect South (12%), SPP North (10%), and NorthernGrid South (7%).
- Reliability has emerged as the primary driver of transmission investments, reflecting the ongoing efforts to ensure a stable and efficient power supply. Thirty-eight percent (38%) of new circuit-miles were driven by reliability needs, followed by aging infrastructure (20%), load growth (17%), and generation (13%). Congestion and public policy were both drivers of less than 1% of new transmission circuit-miles.

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[33] For reference, current transmission system in the contiguous United States is estimated to be 526,028 circuit-miles, as calculated by summing the length of all lines greater than or equal to 69 kV from the Homeland Infrastructure Foundation-Level Data (HIFLD) spatial data for transmission. The 85,000 circuit-miles added since 2016 would represent 16% of total existing circuit-miles.

Transmission investments have maintained at a steady pace since 2016.

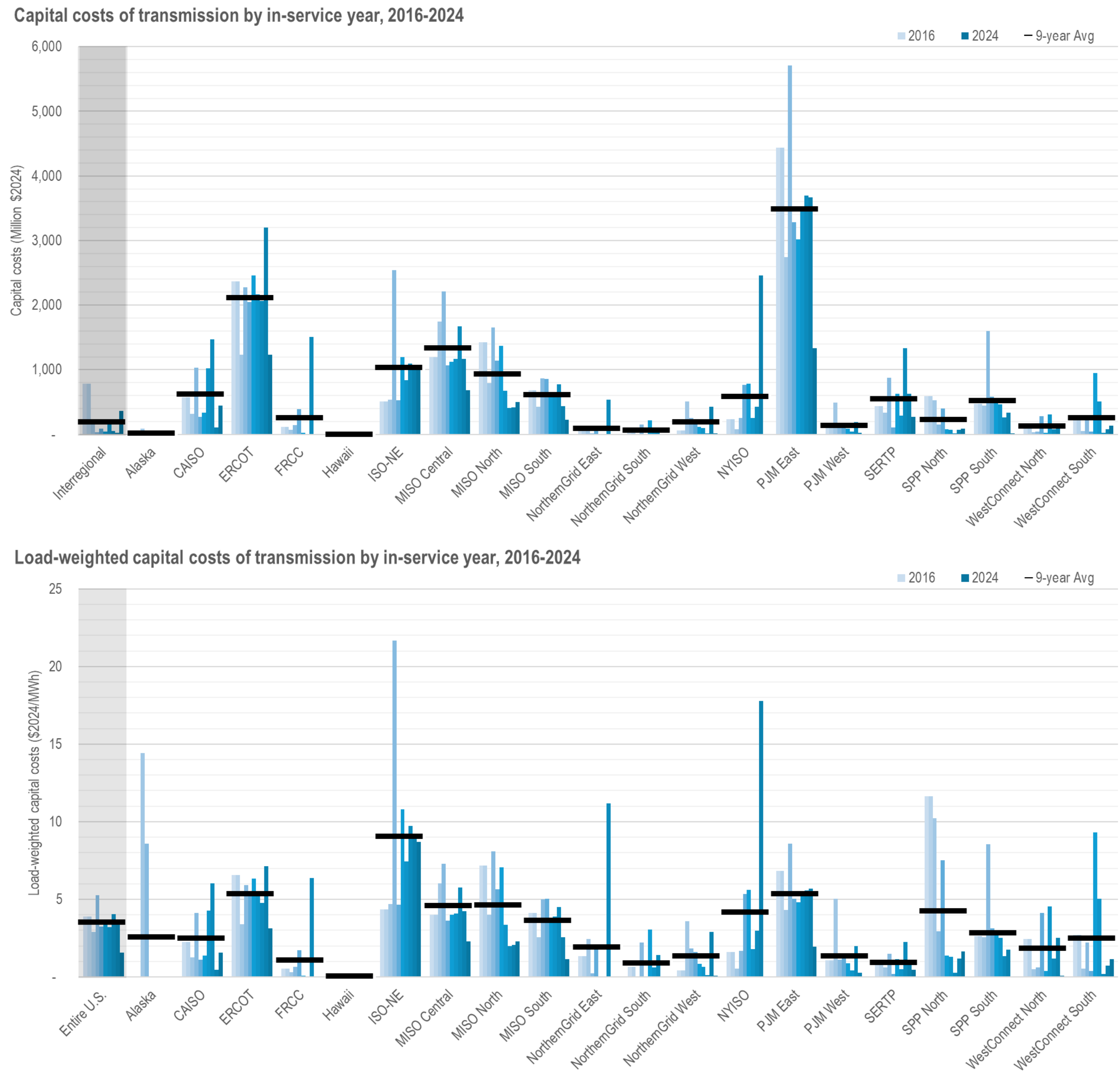
Historical investments are presented in this section in terms of capital costs and circuit-miles of transmission, determined by the year the transmission project was put into service (i.e., *energized*). FERC presented data from 2008 to 2015 in its metrics report (FERC, 2017); investments from 2016 to 2024 were considered. Figure IV-1 (top) shows the total annual capital costs of new, upgraded, or rebuilt transmission lines rated at least 69 kV in each region[34] between 2016 and 2024.[35] Capital costs and circuit-miles for all interregional lines (a line that connects one region to another region or nation)[36] are separated from those lines that begin and end in the same region. The same information weighted by regional annual net load (load delivered by the transmission system, not including behind the meter generation) is presented in Figure IV-1 (bottom). The load-weighted costs for all regional and interregional projects are also shown ("Entire U.S.").[37] The total annual circuit-miles constructed with these capital costs are presented in Figure IV-2. The nine-year averages for all four metrics in each region are shown as black horizontal lines in Figure IV-1 and Figure IV-2, and summarized in Table IV-1.

[34] Data for Alaska and Hawaii may be limited and/or incomplete due to a limitation in the database.

[35] Regional transmission investments over the span of nine years were analyzed. Any investments made prior to 2016 or after 2024 are not shown. Chapter VII of this report provides the current total regional transmission capacity (terawatt-miles) from *Standard Scenarios Report: A U.S. Electricity Sector Outlook* (NREL, 2024b) and the *National Transmission Planning Study* (DOE, 2024b). The regions with the most transmission capacity in 2025 are PJM East, NorthernGrid West, ERCOT, and SERTP, respectively. A comparison of cumulative regional transmission capacity can provide insights when combined with the annual investments presented in this section.

[36] Where DOE uses the terminology "interregional," "intraregional," or "within-region" transmission infrastructure or needs in this chapter, DOE refers to the 20 Needs Study regions displayed in Figure III-4 in Chapter III of this study.

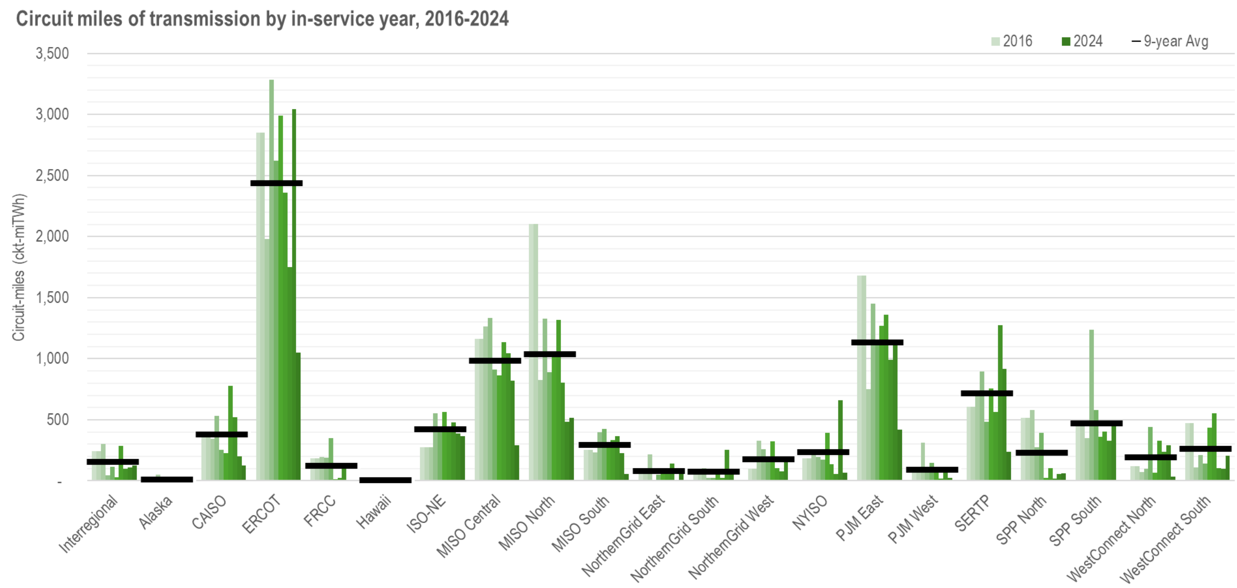
[37] The capital costs shown in Figure IV-1 and Table IV-1 differ from the total transmission investments utilities may spend in a region on an annual basis. The analysis outputs of Figure IV-1 and Figure IV-2 across the four metrics capture capital costs of transmission lines energized in each year. This analysis does not include the ongoing development costs of projects that might be energized in future years, nor does it encompass the operational and maintenance costs of projects already in service.

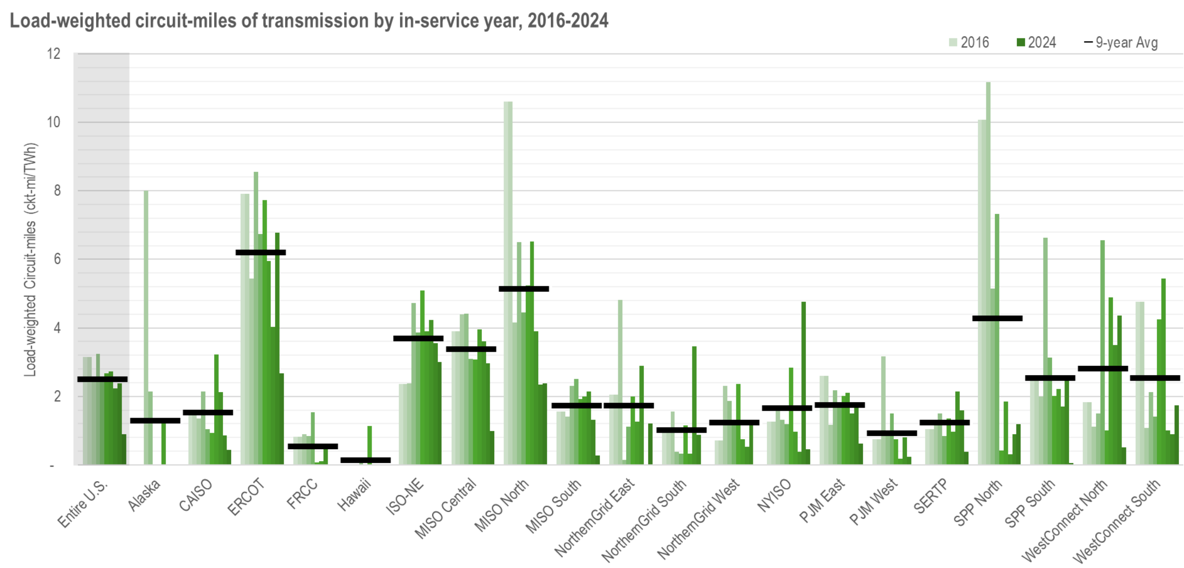


Source: Cost data from Yes Energy Transmission Database (Yes Energy, 2025); Alaska and Hawaii load data from Energy Information Administration (EIA) State Electricity Profiles (2025c). All other regional load data are from the National Renewable Energy Laboratory 2023 Standard Scenarios Report: A U.S. Electricity Sector Outlook*, specifically the 2024 Mid-case Current Policies scenario (NREL, 2024a).*

Note: Not all projects in the database have costs reported. Total capital costs may be higher than reported here. Interregional costs are for projects that terminate in different regions, including international lines. Load-weighted costs for the Entire U.S. category encompass both regional and interregional lines. Load data for Alaska and Hawaii were available only up until 2023 at the time of this analysis, so 2023 load values are used for 2024 in the analysis calculations. Data for Alaska and Hawaii may be limited and/or incomplete due to a limitation in the database.

Figure IV-1. Capital costs (top) and weighted by load (bottom) for new, upgraded, or rebuilt transmission lines (≥69 kV). Horizontal bars indicate nine-year averages.





Source: Circuit-mile data from Yes Energy Transmission Database (Yes Energy, 2025); Alaska and Hawaii load data from EIA State Electricity Profiles (EIA, 2025c). All other regional load data are from National Renewable Energy Laboratory 2023 Standard Scenarios Report: A U.S. Electricity Sector Outlook, *specifically the 2024 Mid-case Current Policies scenario (NREL, 2024a).*

Note: Interregional circuit-miles are for projects that terminate in different regions, including international lines. Load-weighted circuit-miles for the Entire U.S. entry encompass both regional and interregional lines. Load data for Alaska and Hawaii were available only up until 2023 at the time of this analysis, so 2023 load values are used for 2024 in the analysis calculations. Data for Alaska and Hawaii may be limited and/or incomplete due to a limitation in the database.

Figure IV-2. Circuit-miles (top) and weighted by load (bottom) for new, upgraded, or rebuilt transmission lines (≥69 kV). Horizontal bars indicate nine-year averages.

Table IV-1. Nine-year average of annual sums of capital costs and circuit-miles—load weighted and not—for new, upgraded, and rebuilt transmission rated above 69 kV and energized between 2016 and 2024 across the entire United States, interregional circuits, and each region.

Region	Capital Costs (Million 2024$ per yr)[a]	Load-Weighted Capital Costs (2024$/MWh per yr)[a]	Circuit-Miles (ckt-mi)	Load-Weighted Circuit-Miles (ckt-mi/TWh per yr)
Entire U.S.[b]	13,000	3.5	9,400	2.5
Interregional[c]	190	N/A	150	N/A
Alaska	16	2.6	7.8	1.3
CAISO	620	2.5	374	1.5
ERCOT	2,100	5.3	2,400	6.2
FRCC	250	1.1	120	0.53
Hawaii	0.26	0.03	1.2	0.13
ISO-NE	1,000	9.0	420	3.7
MISO Central	1,300	4.6	980	3.4
MISO North	930	4.6	1,000	5.1
MISO South	610	3.6	290	1.7
NorthernGrid East	90	1.9	80	1.7
NorthernGrid South	62	0.89	71	1.0
NorthernGrid West	190	1.3	170	1.2
NYISO	580	4.1	240	1.7
PJM East	3,500	5.4	1,100	1.7
PJM West	130	1.4	90	0.92
SERTP	550	0.94	710	1.2
SPP North	220	4.2	230	4.3
SPP South	520	2.8	470	2.5
WestConnect North	120	1.8	190	2.8
WestConnect South	250	2.5	260	2.5

[a] Not all projects in the database have costs reported. Total capital costs may be higher than reported here.

[b] The row labeled "Entire U.S." reports the total capital costs and circuit-miles for all regions and interregional in the table; load-weighted values are reported by dividing by total U.S. load.

[c] Cost and circuit-miles for interregional projects are reported, but load-weighted values are not applicable because the load extends across multiple regions.

Source: Circuit-mile and cost data from Yes Energy Transmission Database (Yes Energy, 2025); Alaska and Hawaii load data from EIA State Electricity Profiles (2025c). All other regional load data from National Renewable Energy Laboratory 2023 Standard Scenarios Report: A U.S. Electricity Sector Outlook, *specifically the 2024 Mid-case Current Policies scenario (NREL, 2024a). Rounded to two significant figures.*

Transmission investments resulted in a national total of 85,000 circuit-miles of newly constructed, upgraded, and rebuilt transmission lines rated above 69 kV, which were energized between 2016 and 2024. These investments have maintained a relatively steady pace for the U.S. as a whole during the years 2016 to 2023: Between 8,700 to 12,500 circuit-miles were installed each year. However, in 2024, the number of circuit-miles installed dropped to approximately 3,600 circuit-miles. Transmission investments can seem unevenly distributed or "lumpy" when viewed on an annual basis. Some projects can be in the development stage for several years and may all then be put into service in the same year, giving the appearance of large investments during that single year without consideration for when projects first entered the development pipeline.

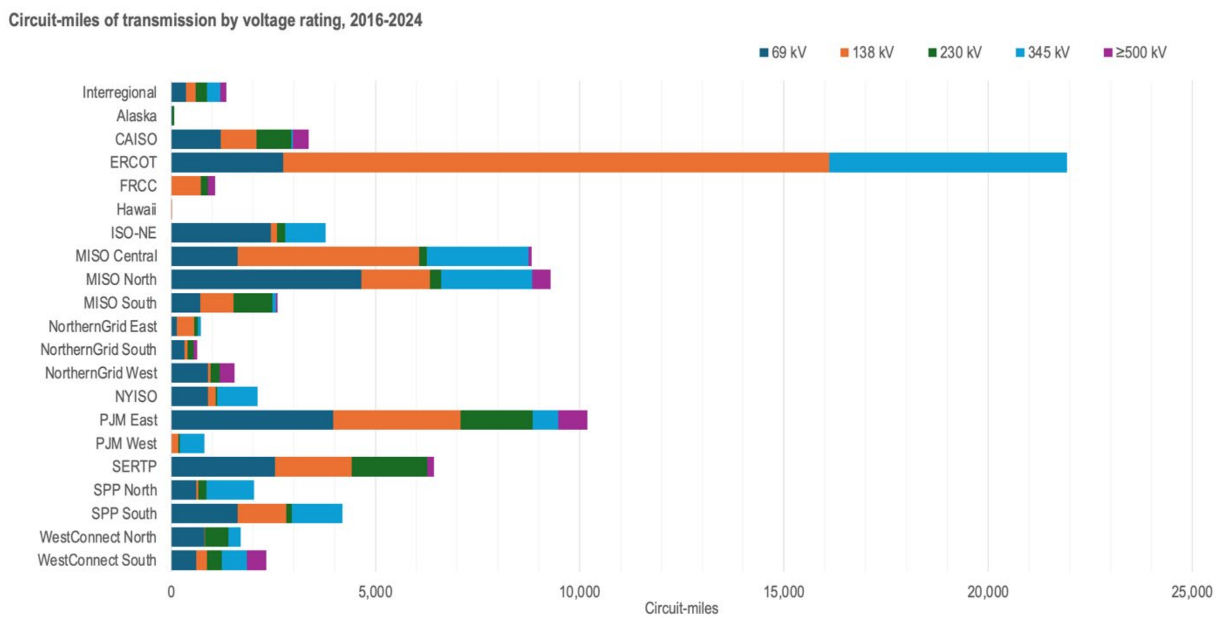
Cumulatively, ERCOT built more circuit-miles than any other region over the analysis period, averaging roughly 2,400 circuit-miles per year. The Alaska, FRCC, Hawaii, NorthernGrid South, NorthernGrid West, PJM West, and SERTP regions installed the fewest circuit-miles relative to regional load throughout the nine-year span.

Within each region, the capital expenditures on transmission infrastructure vary somewhat year-over-year but do not display large upward or downward trends between 2016 and 2024. Load-weighted investments in transmission projects installed help illustrate the magnitude of projects energized relative to the load delivered by the transmission system. Regions like ISO-NE, NYISO, and Alaska show significant spikes of investment throughout the years relative to the electricity demand of the system. Whereas NYISO and Alaska show occasional spikes over the nine-year period, ISO-NE's average dollar spent per megawatt-hour (MWh) of load over this period is the highest, indicating consistent investment in transmission infrastructure. Conversely, few regions show notably lower investment over the nine-year span, with average costs per load of investments below $1.50 per MWh: FRCC, Hawaii, NorthernGrid South, NorthernGrid West, PJM West, and SERTP. Some differences in costs between regions are expected and can be attributed to differences in construction costs per mile across regions—driven by differences in terrain, vegetation, road access, and population densities. Other differences in costs between regions may be driven by reliability needs, the age of infrastructure, and growth patterns, as discussed later in this chapter.

Transmission development by voltage varies from region to region.

Figure IV-3 displays transmission project installation by region and voltage rating. Over the past nine-year period at a national level, the split has been even between 69 kV and 138 kV rated lines, at approximately 31% and 35%, respectively. Over the analysis period, 21% of the transmission projects installed were rated at 345 kV. The highest voltage transmission lines rated at 500 kV or above hold a 4% share of the projects built nationally. These trends can vary from region to region depending on several factors, including seasonal demand and varied power requirements.

Figure IV-3 also illustrates the range in volume of project installation among the regions, showing the cumulative number of circuit-miles installed, which differs from Figure IV-2 in which the circuit-miles are split by year. Over the nine-year analysis period, ERCOT has installed the highest quantity of energized transmission lines, totaling roughly 21,900 circuit-miles, followed by PJM East, MISO North, and MISO Central—each energizing between 8,800 to 10,200 circuit-miles.



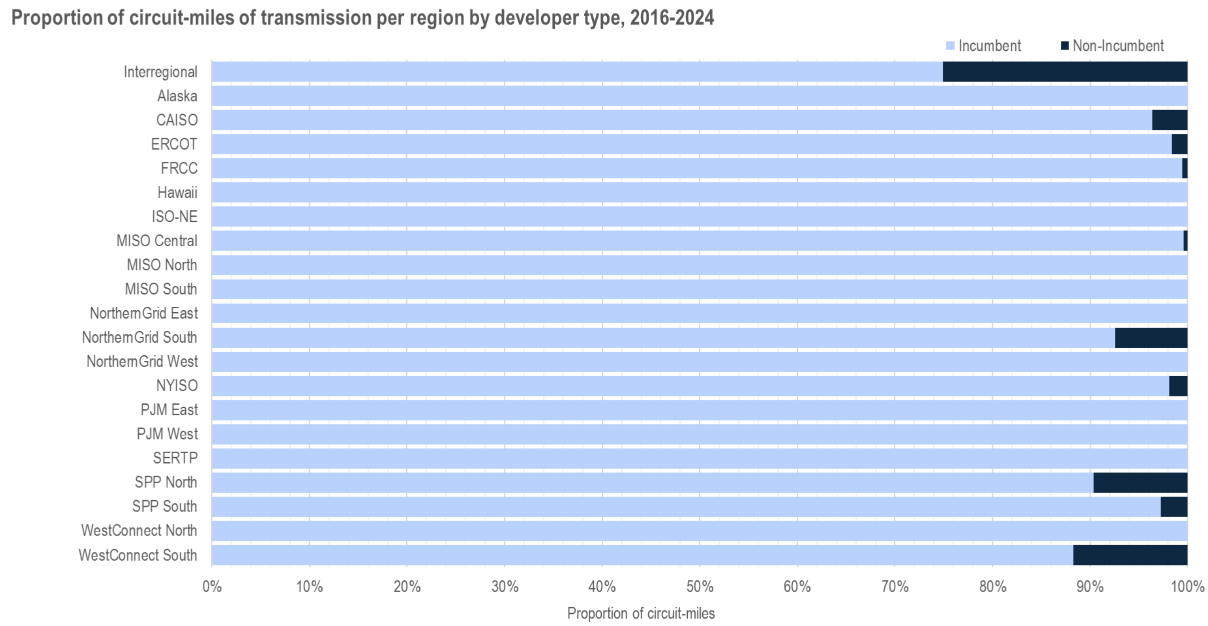
Source: Data from Yes Energy Transmission Database (Yes Energy, 2025).

Note: Data for Alaska and Hawaii may be limited and/or incomplete due to a limitation in the database.

Figure IV-3. Circuit-miles for new, upgraded, or rebuilt transmission lines (≥69 kV) energized between 2016 and 2024, by voltage.

Incumbent utilities installed most transmission facilities.

Between 2016 and 2024, incumbent transmission developers—entities that develop transmission within their own retail distribution footprint—dominated the project development space nationwide, building 98% of the circuit-miles. Excluding interregional data, NorthernGrid South, SPP North, and WestConnect South show the highest proportions of transmission circuit-miles installed by non-incumbent developers—entities that do not have a retail distribution footprint or that are public utilities developing transmission outside their footprint—at roughly 7%, 10%, and 12% of their transmission lines, respectively (Figure IV-4). All other regions have less than 4% of non-incumbent transmission development, with 11 of the 20 regions having 0% new circuit-miles built by non-incumbent transmission developers.



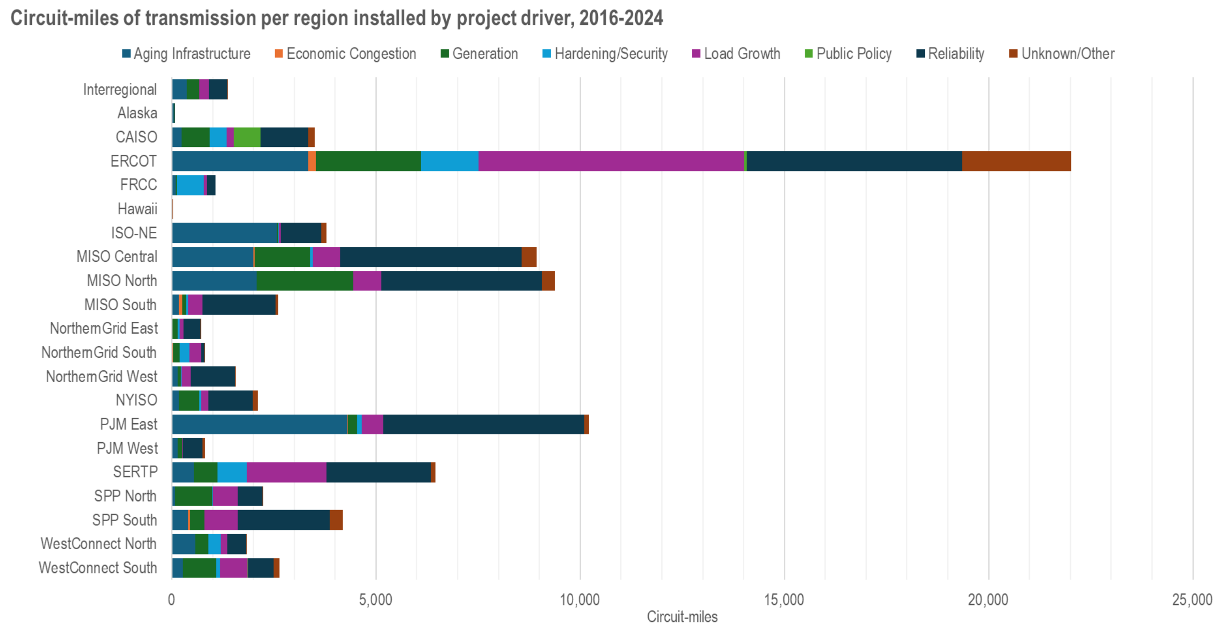
Source: Data from Yes Energy Transmission Database (Yes Energy, 2025).

Note: Data for Alaska and Hawaii may be limited and/or incomplete due to a limitation in the database.

Figure IV-4. Proportion of circuit-miles of new, upgraded, or rebuilt transmission lines (≥69 kV) energized between 2016 and 2024, by project developer type.

Reliability needs were the primary driver of transmission investments in most regions.

Transmission projects can be driven by needs related to aging infrastructure, economic congestion, generation, hardening/security, load growth, public policy, reliability, or unknown/ other. Each project data point captured in this analysis is linked to one of eight primary drivers (Figure IV-5 and Figure IV-6). This metric can inform which needs may be guiding transmission investments nationwide. The definitions of these eight factors can be found in *Section IV* of the Supplemental Materials.

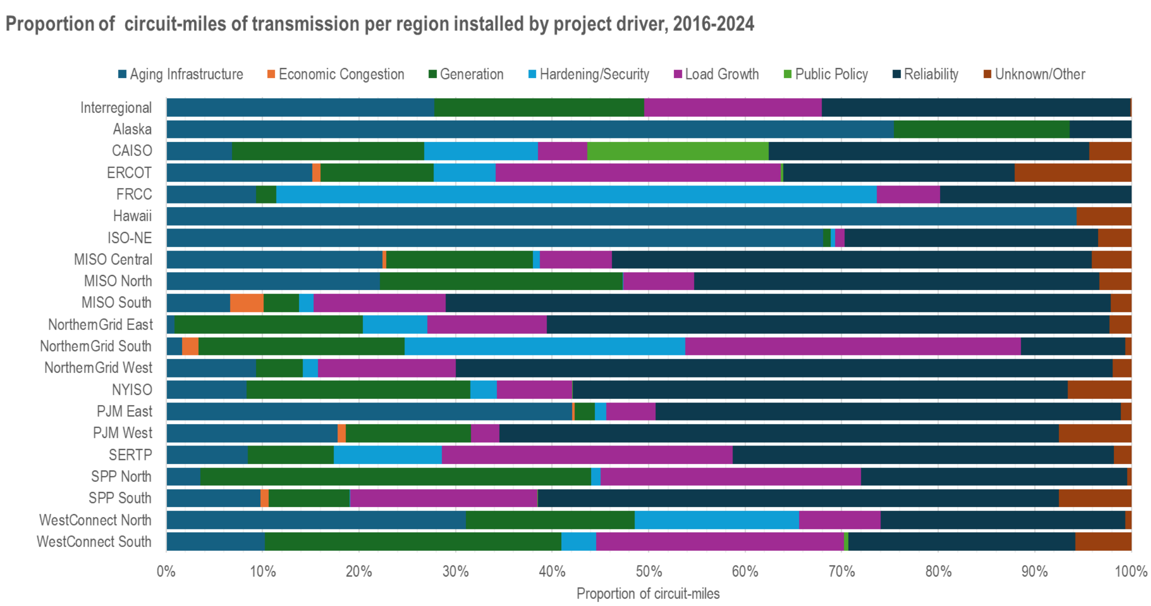


Source: Data from Yes Energy Transmission Database (Yes Energy, 2025).

Note: Data for Alaska and Hawaii may be limited and/or incomplete due to a limitation in the database.

Figure IV-5. Circuit-miles for new, upgraded, or rebuilt transmission lines (≥69 kV) energized between 2016 and 2024, by project driver.

Figure IV-5 illustrates the primary driver for all new or rebuilt transmission lines (rated at or above 69 kV, with the exception of Alaska and Hawaii), between the years of 2016 and 2024 across the U.S. by region. Figure IV-6 shows the proportion of each primary driver leading investment in this project space. Approximately 40% of the total circuit-miles across the nation are driven by *reliability*, totaling roughly 32,800 circuit-miles installed over the nine-year period.



Source: Data from Yes Energy Transmission Database (Yes Energy, 2025).

Note: Data for Alaska and Hawaii may be limited and/or incomplete due to a limitation in the database.

Figure IV-6. Proportion of national circuit-miles of new, upgraded, or rebuilt transmission lines (≥69 kV) energized between 2016 and 2024, by project driver.

While *reliability* may be a primary driver in many regions (especially in those with a larger portfolio of circuit-miles installed), it is not necessarily the case for all regions. For example, most of the circuit-miles installed in the region served by ERCOT during this period were primarily driven by *load growth*, very closely followed by *reliability* at approximately 6,500 circuit-miles and 5,300 circuit-miles, respectively.

Similarly, *aging infrastructure* ranks highest as a primary driver for regions like Alaska, Hawaii, ISO-NE, and West Connect North. As a nation, *aging infrastructure* drives roughly 20% of projects in this space, totaling 17,600 circuit-miles.

A majority of projects in regions like NorthernGrid South, SPP North, and WestConnect South were primarily driven by *generation*. Across all regions, this driver influences roughly 13% of circuit-miles installed, totaling approximately 11,600 circuit-miles nationally.

The project data available for FRCC indicates that *hardening/security* seems to be the leading driver for that region, which accounts for approximately 670 circuit-miles. Across all regions, *hardening/security* drives about 5% of the circuit-miles installed nationwide, totaling roughly 4,300 circuit-miles.

Economic congestion-driven projects tend to propel a lower portion of installed circuit-miles, making up 0.5% of all the projects nationwide. For ERCOT, about 12% of circuit-miles installed are flagged as *unknown or other* as the primary driver. However, for the remaining regions, this proportion is a lot lower, at 8% or less. As a nation, 5% of total circuit-miles are installed for *unknown or other* reasons.

V. Historical Transmission System Benefits and Constraints

The transmission system provides significant value to energy consumers, both in reducing costs during typical operations and improving reliability during periods when the grid is the most stressed. Much of the economic value of transmission is associated with carrying lower-cost power from where it is generated to areas with higher demand. However, the transmission system does not always have sufficient capacity to deliver as much lower-cost energy as there may be supply of and demand for, as a result of physical and operational constraints of the transmission network and generation assets. When sufficient transmission capacity is not available to deliver power from lower-cost generation sources throughout the network to meet consumer demand, higher-cost generation must be dispatched near the load. These conditions are known as transmission congestion. Transmission congestion increases the average wholesale price of electricity because power from low-cost generation resources cannot be delivered to the end user. Investing in regional and interregional transmission infrastructure can alleviate congestion and improve competition in wholesale electricity markets by removing barriers for low-cost generation to compete (FERC, 2020).

Transmission also serves a role in enhancing reliability in geographically isolated locations, improving resilience during severe weather or cyber or physical attacks, and enhancing resource adequacy by enabling regions to share power. Interregional transmission can provide significant resource adequacy value when grid regions experience peak stress periods at different times, driven by differences in weather patterns, load profiles, and resource mixes. Transmission can play a similarly important role in providing redundancy during emergency events that stress particular portions of the bulk power system, as well as during a wide range of planned or unplanned outage events in geographically isolated systems.

This chapter reviews the historical and current transmission system operations, value, and constraints focusing on existing transmission congestion on the grid and bulk transmission system operations during periods of greatest stress and emergency events. Information presented in this chapter encompasses both new analyses from DOE's national laboratories and a literature review to highlight historical capacity constraints and congestion on the U.S. bulk power system. A comprehensive list of the reports referenced in this study can be found in *Current and Future Needs Assessment through Review of Existing Studies* of the Supplemental Materials (*see* Table S-16). Key findings from this chapter include:

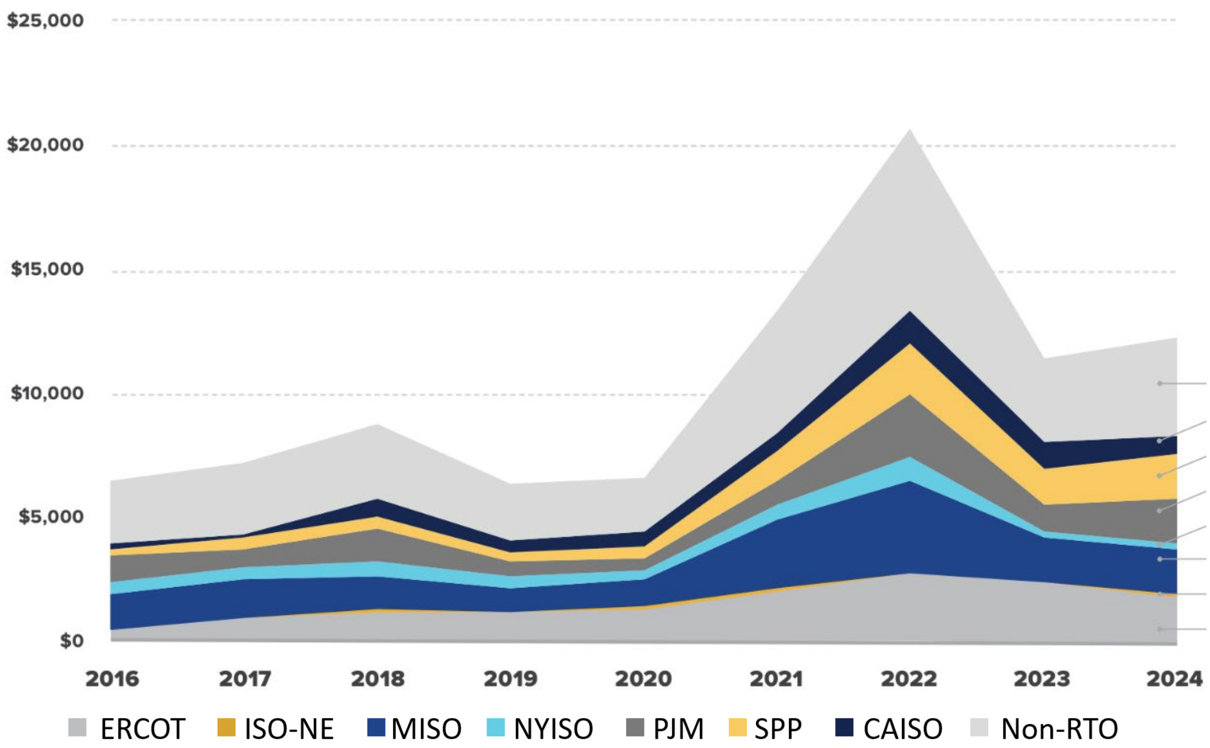
- Transmission congestion exists across all regions of the U.S., increasing wholesale electricity prices. Factors such as severe weather events and fuel price volatility lead to annual variations in congestion costs, which peaked in 2022.
- Most transmission congestion value that could be accrued from new transmission links is concentrated during times when unforeseen changes in conditions occur within one day of operations (e.g., forecast errors), especially when there is also high net load or cold weather.

- Interregional and cross-interconnection transmission linkages typically show the highest potential to reduce the average wholesale price of electricity.
- Within regions, CAISO, SPP, and ERCOT experience the highest load-weighted congestion costs, while ISO-NE and MISO have the least congestion.
- Despite limited data to understand transmission congestion in the Southeast, new analyses estimate average transmission congestion value near $10/MWh for intraregional links.
- Transmission investment can relieve congestion and reduce wholesale electricity prices in the long term.
- Because load profiles and resource mixes vary across regions, interregional transmission supports resource adequacy by enabling regions to import power from each other when additional supply is needed.
- Transmission system hardening and expansions that create redundancy can improve resilience in isolated regions and during emergency events.

This chapter begins by exploring current transmission congestion and transfer capabilities on a national and interregional level (*Section V.a*). Then, the current state of congestion management approaches are described for each RTO/ISO region followed by non-RTO/ISO regions (*Section V.b*). Lastly, the role of the transmission system in enhancing reliability and resource adequacy is discussed (*Section V.c*).

V.a. National and Interregional System Congestion and Transfer Capabilities

Across the U.S., transmission congestion increases the average wholesale price of electricity. Investing in new transmission to connect nodes between or within regions can mitigate some of the costs associated with transmission congestion. Nationwide, congestion costs are estimated to be $11 billion in 2023 and $12 billion in 2024, down from a high of $21 billion in 2022 (Figure V-1) (GridStrategies, 2025). High congestion costs in 2022 were driven by natural gas price increases and severe weather events, such as Winter Storm Elliott in December 2022, which led to increased electricity load across regions (GridStrategies, 2025). Despite some year-over-year variation, GridStrategies (2025) expect nationwide congestion costs to continue trending upward because of generation retirement and replacement and inadequate transmission expansion, slowing the development of new, low-cost generation.



Source: GridStrategies (2025).

Note: The legend at the bottom of this image was added by DOE to improve legibility. Congestion rents, as reported by RTOs/ISOs, are used as the approximation of the congestion cost (y-axis, $M). Congestion costs for non-RTO/ISO regions are estimated by scaling the congestion costs of all other regions by electricity demand in non-RTO/ISO regions.

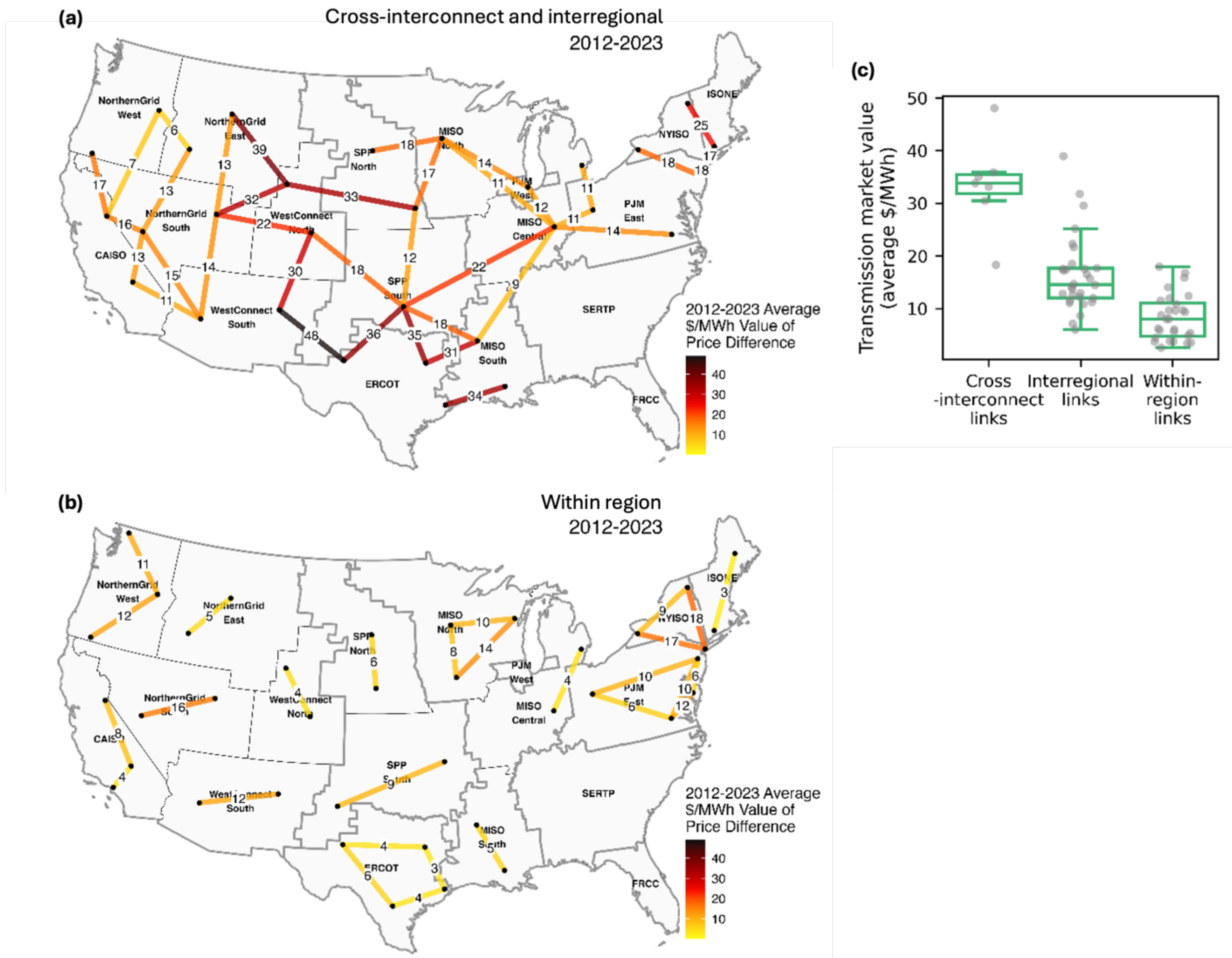
Figure V-1. Regional transmission congestion costs in millions of U.S. dollars for 2016–2024.

Interregional and cross-interconnection transmission links show the highest potential value to relieve transmission congestion.

Locational marginal price (LMP) is defined as the marginal cost of supplying the next increment of energy demand at a particular location, considering factors like generation costs, demand, and transmission constraints. Differences in the LMP of electricity at different wholesale market pricing nodes can highlight existing transmission congestion in the system. Differences in LMPs indicate that the system's transmission constraints limit the ability to deliver lower priced generation from one node to customers at the higher price node. Adding transmission reinforcements on a path between the two nodes to alleviate transmission constraints would provide some congestion relief value by lowering the average LMP across the two nodes. Lawrence Berkeley National Laboratory (LBNL) analyzed differences in real-time LMPs between 65 pairs of pricing nodes across the Need Study regions within the contiguous U.S. from 2012 to 2023 to approximate the value of connecting the two nodes with new or reinforced transmission infrastructure (LBNL, 2025b). Figure V-2 shows the 65 hypothetical transmission links explored, which include 28 links within a region, 30 links between Needs Study regions within the same interconnection, and seven links between interconnections.

According to LBNL's analysis, transmission links crossing electricity market seams between regions or interconnections show the highest potential for transmission congestion value, as indicated by the differences in LMP which can be seen in Figure V-2 (c). For example, cross-interconnection links from ERCOT to neighboring regions show some of the highest LMP differentials from $31/MWh to $48/MWh averaged across all hours from 2012 to 2023, and links between Western Interconnection (WestConnect) and Eastern Interconnection (SPP) have LMP differentials from $18/MWh to $33/MWh averaged across all hours from 2012 to 2023 (Figure V-2 (a)). Links between regions within an interconnect also have transmission congestion value, particularly between NorthernGrid and WestConnect and between ISO-NE and NYISO. Transmission links within regions have lower LMP differentials, with the highest-value within-region links between New York City and the rest of NYISO ($17–$18/MWh) and within NorthernGrid South ($15/MWh) (Figure V-2(b)).

LBNL's analysis also finds that many links are fairly balanced in terms of which direction power flow would be valuable over time. Considering the value of flow in only one direction captures just 61%–75%, 60%–76%, and 61%–83% (25th to 75th percentile) of the value for cross-interconnect, interregional, and within-region links, respectively. Thus, these transmission links would provide value at both ends of the link because each terminal experiences times when lower-cost generation is available on the other side.



Source: Lawrence Berkeley National Laboratory (2025b).

Note: The maps of the mean marginal transmission market values for the analyzed links are divided into (a) cross-interconnect and interregional links and (b) within-region links. In some cases, the analyzed timeframe begins after 2012 (LBNL, 2025b). The graphic indicated by (c) is the distribution of mean marginal transmission market values across the set of 65 analyzed links (real-time market). Each point represents one link.

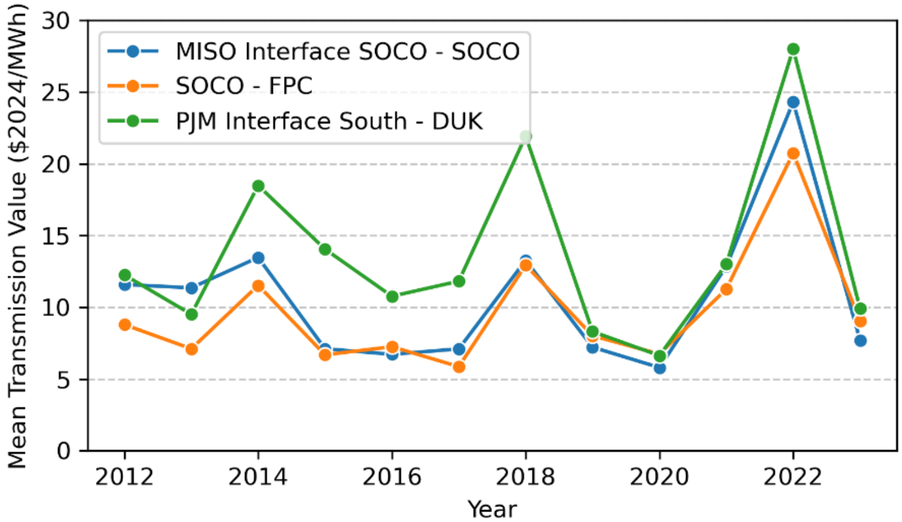
Figure V-2. Maps of mean marginal transmission market values for all 65 analyzed links over the entire study period (real-time market) (a) and (b) and the associated distribution (c).

Despite limited data in the Southeast, two analyses uncover estimated congestion costs revealing significant year-over-year variation.

In the southeastern U.S., which lacks an RTO/ISO-operated energy market and publicly available LMP data, two approaches are discussed below to provide visibility into transmission congestion in the region. First, LBNL (2025d) used system lambda data in the Southeast reported to FERC to develop a proxy for transmission congestion value.[38] Annual average

[38] There are known limitations in the use of system lambda data to estimate transmission congestion value. Several factors may contribute to over- or underestimation of transmission

interregional transmission congestion value between Southern Company (SOCO) and MISO, SOCO and Duke Energy Florida (FPC), and Duke Energy Carolinas (DUK) and PJM ranged from $6 to $28/MWh with significant year-to-year variation caused by polar vortex events in January 2018, February 2021, and December 2022 (LBNL, 2025d) (Figure V-3).



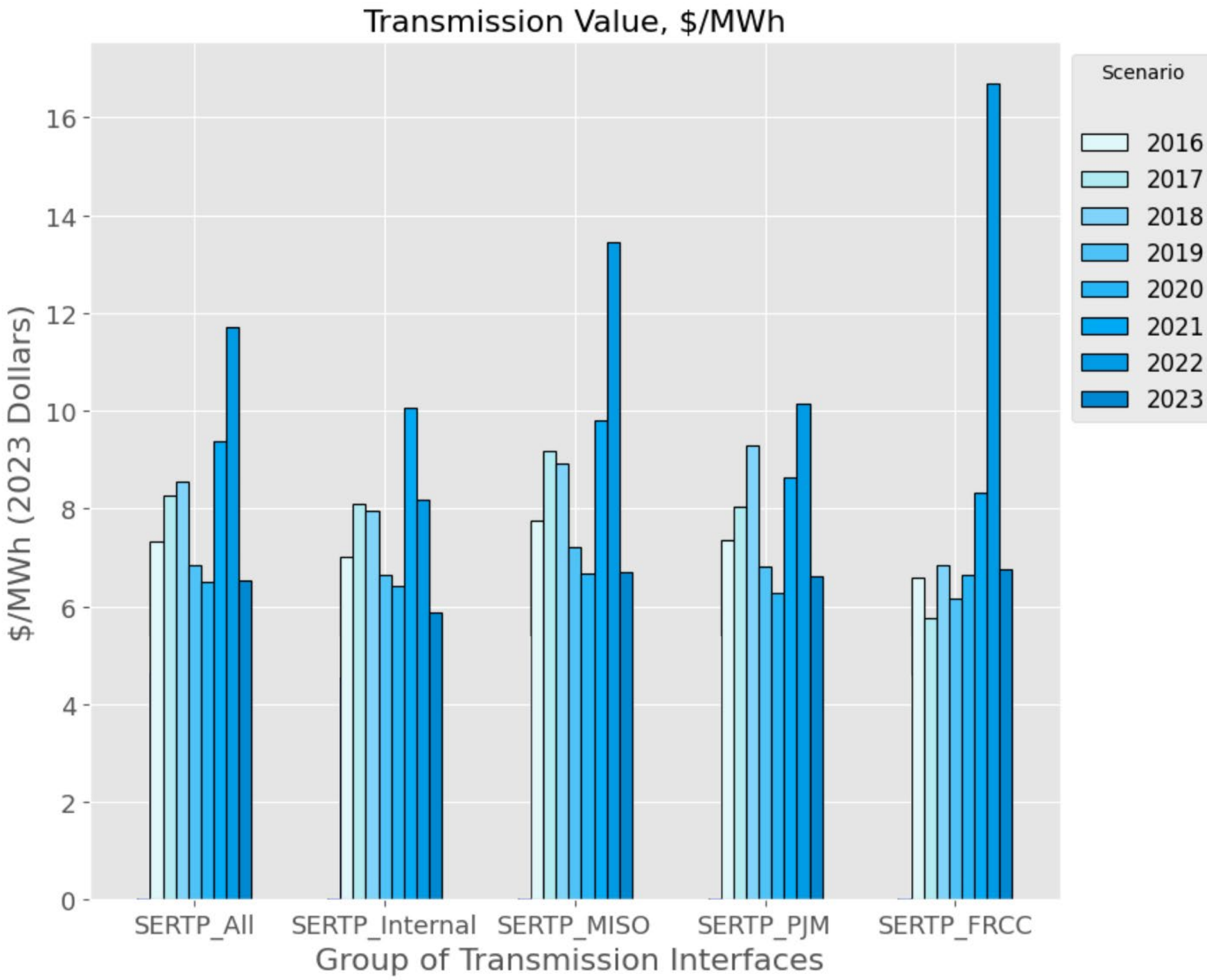
Source: Lawrence Berkeley National Laboratory (2025d).

Figure V-3. Annual average interregional transmission congestion value between the Southeast and other regions from 2012 to 2023, modeled using system lambda data.

Second, using a production cost model to estimate LMPs in the Southeast and neighboring regions from 2016 to 2023, a study from LBNL and the National Laboratory of the Rockies (LBNL and NLR, 2026) found similar transmission congestion value estimates as those from LBNL (2025d). Specifically, LBNL and NLR (2026) found that interregional links provide higher transmission congestion value than links within a region to arbitrage differences in LMP (*see* Supplemental Materials, *Section V.a. National and Interregional System Congestion and Transfer Capabilities: Visibility into Southeast Transmission Value*). The average transmission congestion value between the SERTP[39] and its neighbors, MISO, PJM, and FRCC, was $8.14 and across years ranged between $6.51/MWh and $11.71/MWh (represented as SERTP-All in Figure V-4). Similarly, between FRCC and its neighbor SERTP, transmission value averaged $7.98 and across years ranged from $5.78/MWh to $16.70/MWh. For all interfaces, 2022 had the highest transmission value because it had the highest natural gas prices.

congestion value based on this analysis. For example, NBER (2018) note that these data do not fully account for marginal congestion costs, transmission losses, and conditions in peak periods.

[39] The use of SERTP here refers to the Needs Study sub-planning region displayed in Figure III-4 in Chapter III of this study.

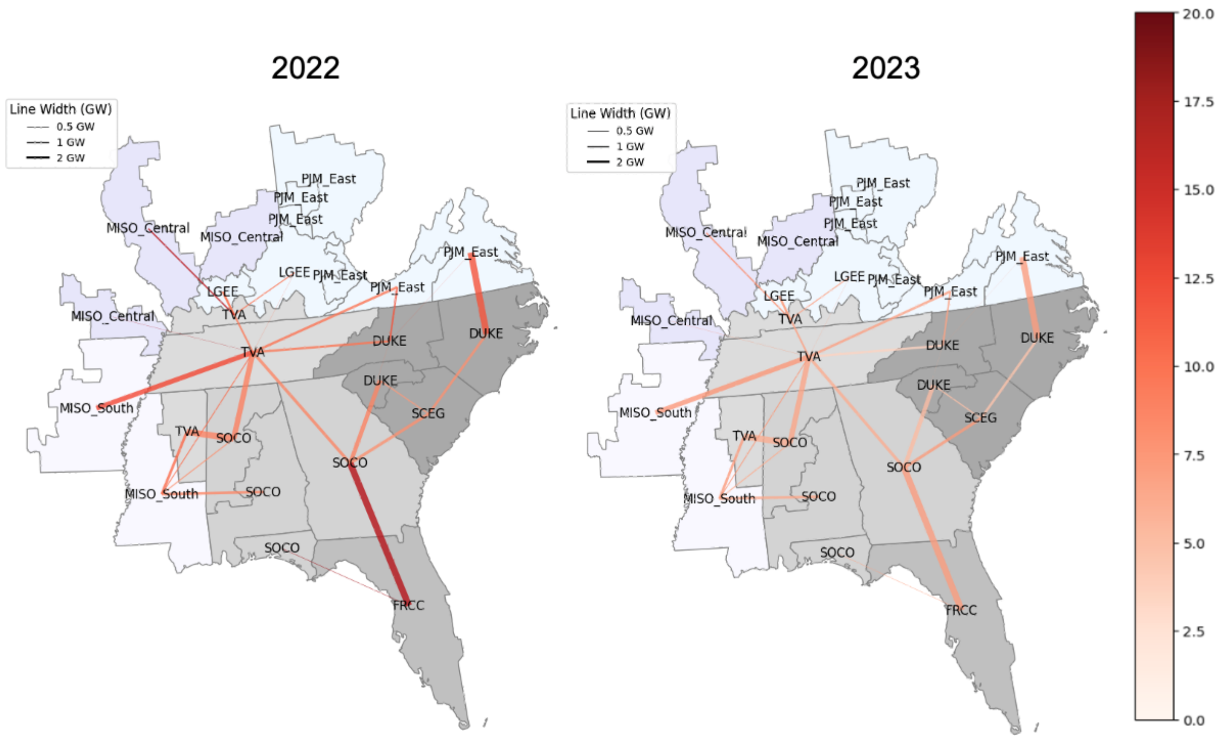


Source: Lawrence Berkeley National Laboratory and National Laboratory of the Rockies (2026).

Note: SERTP_All represents the average of all links; SERTP_Internal represents intraregional links.

Figure V-4. Transmission congestion value between SERTP and its neighboring regions.

Figure V-5 shows transmission value by zone in the Southeast for 2022 (the highest-value year) and 2023 (a lower-value year). Enhanced linkages between zones that have high transmission congestion value would have more influence on reducing congestion than between other zones. The three linkages with the highest transmission congestion value in both 2022 and 2023 are interregional links between SOCO-FRCC, Duke-PJM, and Tennessee Valley Authority (TVA)-MISO South.



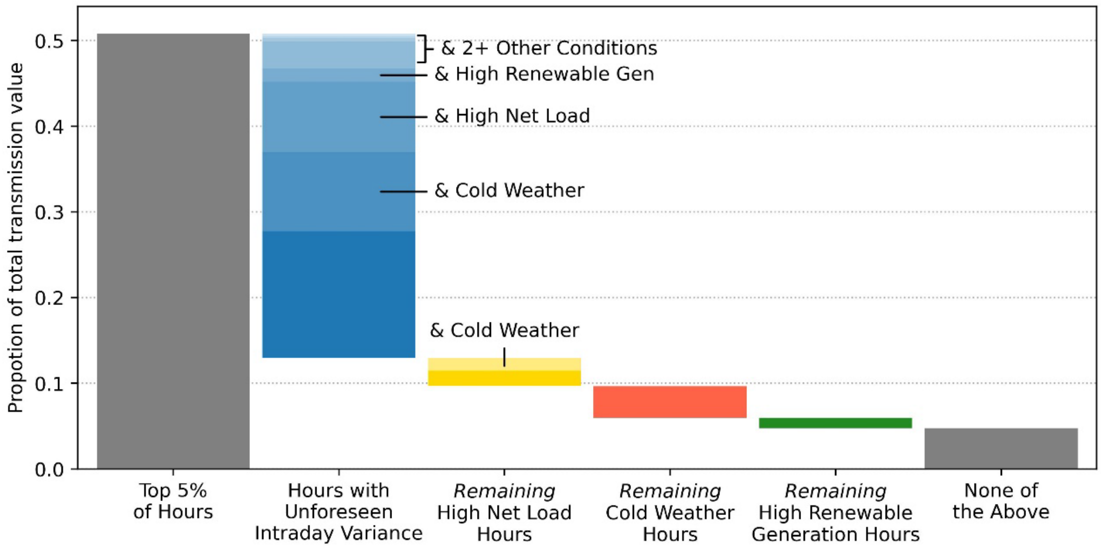
Source: Lawrence Berkeley National Laboratory and National Laboratory of the Rockies (2026).

Figure V-5. Map of transmission congestion value for interregional and intraregional links in the U.S. Southeast derived from LMP extracted from a production cost model.

The two approaches for estimating transmission congestion value from interregional links in the Southeast and Florida show similar results with averages near $10/MWh. For comparison, higher values occur across all RTO/ISO market regions, where the median market price–based estimate of interregional transmission is roughly $15/MWh, and the median cross-interconnect transmission value is roughly $35/MWh (LBNL, 2025b). The estimates of the value of transmission across the Southeast and Florida are comparable, but not equivalent, to these empirical market-based estimates, with important caveats discussed for both approaches (*see* LBNL, 2025d; LBNL and NLR, 2026).

Transmission costs are concentrated in time, with half of transmission congestion value occurring in 5% of the hours.

The majority of transmission congestion value that could be accrued from new transmission links is concentrated in 5% of the hours during which transmission is extremely valuable. Peak transmission value periods are primarily driven by events that are unforeseen or mis-forecasted roughly 12 to 36 hours before the operating window. Secondary causes include significant stresses on the bulk power system from high net load or cold weather, while high intermittent generation is a tertiary driver of peak hours (Figure V-6, for RTO/ISO regions). Similarly in the Southeast, transmission congestion value is concentrated in a small portion of hours both resulting from severe weather and seasonal patterns during which summer afternoons and fall mornings consistently experience high transmission congestion value.



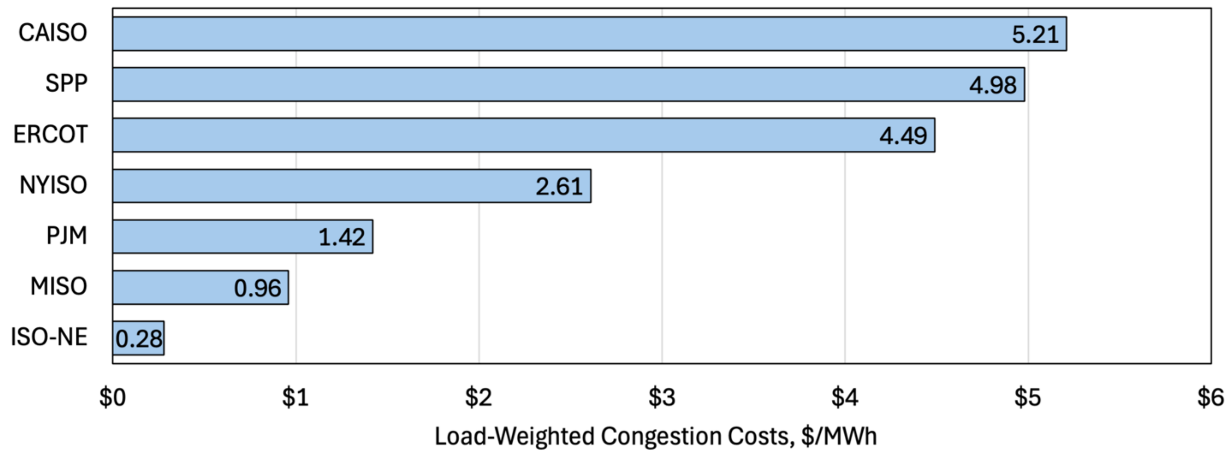
Source: Lawrence Berkeley National Laboratory (2025b).

Note: This figure contains aggregate results for all 41 links studied within or between RTO or ISO regions, excluding those in the non-ISO West. The contribution of key system conditions to transmission market value during peak value hours (top 5%) are visible in the leftmost column. This figure should be read from left to right. When multiple conditions are present at the same time, the associated value appears in the first (i.e., leftmost) applicable column and is identified by lighter segments and "& [overlapping condition]" labels.

Figure V-6. Relationships between four key conditions and peak transmission value (real-time market).

V.b. Regional Congestion Management

Transmission congestion affects the economic and operational efficiency of energy transactions within RTOs and ISOs across the U.S. Congestion costs weighted by total load for each RTO/ISO in 2023 range from less than $1/MWh in ISO-NE and MISO to over $4/MWh in ERCOT, SPP, and CAISO (Figure V-7). The drivers of transmission congestion within these regions include load growth, changing resource mixes, and inadequate transmission. Detailed maps from LBNL (2025a) show the frequency and intensity of congestion at the level of individual lines and substations between 2022 to 2024 for each RTO/ISO region. This subsection reviews congestion patterns, impacts, and management strategies within RTO/ISO regions first followed by non-RTO/ISO regions.



Source: ISO New England Internal Market Monitor (ISO-NE Internal Market Monitor 2024, PDF p. 97 for system load, PDF p. 177 for DA and RT congestion); Potomac Economics (Potomac Economics 2024c, PDF p. 92 for DA congestion and PDF p. 185 for RT congestion); Potomac Economics (Potomac Economics 2024d, PDF p. 82 for DA and RT congestion); Monitoring Analytics, LLC. (Monitoring Analytics 2024, PDF p. 18 for system load, PDF p. 82 for DA and RT congestion); California Independent System Operator (CAISO 2024a, PDF p. 49 for system load, PDF p. 15 for DA congestion, and PDF p. 97 for RT congestion); Southwest Power Pool, Inc. Market Monitoring Unit (SPP Market Monitoring Unit 2024, PDF p. 210 for DA and RT congestion); Potomac Economics (Potomac Economics, 2024e, PDF p. 229 for DA and RT congestion); Electric Reliability Council of Texas system load from 2023 Demand and Energy Report (ERCOT, 2024a); New York Independent System Operator system load from 2024 Load & Capacity Data (NYISO 2024b, PDF p. 27); Southwest Power Pool load from 2022 and 2023 Hourly Load (SPP, 2025a); Midcontinent Independent System Operator system load calculated from MISO 2023 Regional Actual Load (MISO, 2023a).

Note: Factors considered in calculating the congestion cost may vary from region to region; therefore, these load-weighted congestion costs represent best estimates and are presented for comparison purposes.

Figure V-7. Load-weighted congestion costs in 2023 for each RTO/ISO.

CAISO

California intrastate transmission congestion predominantly affects south-to-north flows, whereas congestion effects have declined on most interregional interties. Within CAISO, transmission congestion affected day-ahead prices in 36% of the hours in 2022 and 51% of the hours during 2023 (CAISO, 2024a). On average, throughout 2023, day-ahead market internal congestion led to increased prices in the Pacific Gas and Electric (PG&E) and San Diego Gas and Electric (SDG&E) service areas and to decreased prices in the Southern California Edison (SCE) service area. Ultimately, day-ahead market congestion costs (congestion rents and loss surpluses) were $1.1 billion in 2023, which was a decrease from $1.4 billion in 2022.

Real-time market congestion within CAISO is driven by seasonal trends in solar production and electrical demand. Days with high solar output and low load lead to congestion in the south-to-north direction, creating low prices in Southern California relative to Northern California and neighboring regions. Conversely, low solar output and high loads lead to congestion in the north-to-south direction. In 2023, the direction of real-time market congestion was predominantly from south to north, while north-to-south congestion occurred more frequently during evening hours and throughout 2022 (CAISO, 2024a).

To manage the impacts of congestion on ratepayers, CAISO uses a congestion revenue rights (CRR) market to auction or allocate congestion costs to market participants. In 2019, the CRR market underwent changes with the goal of improving efficiency and increasing payouts to ratepayers. The changes to the market have decreased losses borne by transmission ratepayers relative to the pre-2019 CRR market, but the payouts from the auction still exceed revenue generated from the auction, resulting in ratepayer losses of $117 million in 2022 and $59 million in 2023 (CAISO, 2024a).

ERCOT

Transmission constraints within ERCOT resulted in $2.8 billion and $2.4 billion of transmission congestion in the real-time market in 2022 and 2023, respectively (Potomac Economics, 2024c). Lower transmission congestion in 2023 was largely due to a decrease in natural gas prices. Congestion was highest in the south and west zones. Houston experienced significantly lower congestion in 2023 than in the previous two years, which resulted from the completion of transmission upgrades. The costliest transmission constraint in ERCOT during 2023 for both the day-ahead and real-time market was the Tango Pawnee Calaveras 345 kV line, which serves the San Antonio region. The real-time congestion value of the constraints on that line was estimated at $202 million during 2023, calculated by multiplying the shadow price by the flow over the constraint (Potomac Economics, 2024c). Revenue generated by ERCOT's CRR markets has increased year-over-year since 2016, reaching $1.4 billion in 2023, although the payments to CRR owners exceeded the revenues in each of these years (Potomac Economics, 2024c).

To manage grid stability, ERCOT has increasingly relied on generic transmission constraints (GTCs), which are non-thermal limits applied to transmission elements to restrict generator dispatch that could cause voltage or transient instability. Derived from off-line analyses, GTCs are typically deployed to limit the dispatch of inverter-based resources. Approximately 11% of all real-time congestion is associated with GTCs, with congestion costs of $253 million (Potomac Economics, 2024c). The rising use of GTCs is increasing congestion and limiting the export of low marginal cost generation to load centers. ERCOT is working on methods to calculate GTCs using real-time models instead of off-line studies, which should limit the over-prescription of GTCs and reduce real-time congestion (Potomac Economics, 2024c).

ISO-NE

Lower energy prices and a generally unconstrained transmission system resulted in low congestion revenue in 2023 totaling $30.4 million from day-ahead markets and $1.9 million from real-time markets (ISO-NE Internal Market Monitor, 2024). ISO-NE experienced an average of $0.37/MWh of congestion costs from 2021 to 2023, at just 10%–20% of the average congestion levels in other RTO markets (Potomac Economics, 2024b). ISO-NE's relatively low congestion cost is due to significant transmission investments over the past decade, although such investments resulted in a transmission rate of approximately $22/MWh in 2023—over twice the average rate in other RTO markets (Potomac Economics, 2024b). Therefore, Potomac

Economics (2024b) indicate it is unlikely that additional transmission investment in the region would be economical in the near term.

Some areas of ISO-NE regularly experience transmission congestion, particularly areas in northern Maine, where there is a relatively high concentration of wind generation, and at the interface with New York, where large price differences can occur during winter months when New England's gas infrastructure is constrained (ISO-NE Independent Market Monitor, 2024). Relatedly, ISO-NE's *2023 Regional System Plan* indicates that limited transmission infrastructure in northern and western Maine is the main obstacle to interconnecting new land-based wind resources (ISO-NE, 2023).

MISO

In 2023, real-time congestion was $1.8 billion and day-ahead congestion was $1.1 billion in MISO (Potomac Economics, 2024d). These congestion costs are roughly half of 2022 costs, driven by the decline in natural gas prices and the decrease in overall wind output (Potomac Economics, 2024d). In 2023, 45% of real-time congestion in the MISO region was due to insufficient transmission capacity to support new wind energy resources (GridStrategies, 2024). MISO's independent market monitor, Potomac Economics (2024d), emphasized that MISO failed to capture $270 million of unrealized annual savings in 2023 by not using ambient-adjusted ratings and emergency ratings. The monitor therefore recommends that MISO enable rapid additions of new ambient-adjusted rating elements.

NYISO

Lower natural gas prices, fewer transmission outages, and new transmission infrastructure caused day-ahead and real-time transmission congestion values in NYISO to fall dramatically from over $1.0 billion and $1.2 billion in 2022 to $311 million and $399 million in 2023, respectively (Potomac Economics, 2024e). Decreasing by 69%, day-ahead congestion revenues neared the lowest level observed over the past decade.

Approximately 46% of day-ahead congestion revenues occurred in the first quarter of 2023 when cold weather caused natural gas price spikes, leading to increased congestion from central to east New York (Potomac Economics, 2024e). The completion of the Smart Path project, the Central East Energy Connect (increased transfer capability by 1 gigawatt (GW)), and the AC Transmission Segment A and Segment B projects in 2023 reduced congestion in and out of central New York, particularly the Central East interface. However, roughly 53% of all 2023 congestion still occurred in the Central East interface. Another 19% of 2023 congestion occurred in Long Island where extended forced outages of lines impacted transmission capacity (Potomac Economics, 2024e). Additionally, the interconnection of new wind resources in the Finger Lakes area drove slightly increased congestion along the transmission paths from west to central New York, limiting west-to-east flows on bottlenecks along the Southern Tier of central New York (Potomac Economics, 2024e). Lastly, substantial amounts of variable intermittent generation in the north zone, coupled with significant, low-cost, often inflexible imports from Québec and volatile loop flows passing through from neighboring systems, produced volatile congestion pricing at many transmission bottlenecks in northern New York (Potomac Economics, 2024e).

Without system upgrades, NYISO (2024a) indicates that new intermittent generation sited upstream of the Central East transmission interface, in western, central, and northern New York, will lead to significant curtailment of upstate intermittents. NYISO (2024a) recommends adding dynamic reactive power support to the grid upstate to reduce congestion and maximize the transmission capability of the Central East interface and suggests monitoring opportunities for further transmission investment. NYISO (2024a) also notes that anticipated large loads in upstate New York may help to decrease local transmission congestion and curtailment in intermittent generation pockets, helping to alleviate bulk transmission congestion on the Dysinger East and Central East interfaces.

PJM

In 2022 and 2023, congestion costs in PJM were $2.5 billion and just over $1 billion, respectively (Monitoring Analytics, 2024). Significant transmission bottlenecks currently hinder the delivery of generation to Dominion's data center loads in Virginia. The large number of new interconnection requests, coupled with the fact that the transmission system is nearing its capacity, has resulted in significant congestion and a delayed interconnection study process. GETs, such as dynamic line rating (DLR), offer a way to connect new resources to the grid faster and at a lower cost in the near term. The utility PPL reported that a pilot DLR program in Pennsylvania is saving $23 million per year (RMI, 2024).

SPP

In 2023, SPP saw its highest price variation attributable to congestion since the Integrated Marketplace began in 2014, with congestion driving 89% of the price variations. The primary factors driving congestion in SPP are the transmission grid's physical characteristics, load distribution, regional fuel cost differences, and external flows from neighboring areas. The cost of coal-fired generation in SPP rises as transportation costs increase with distance from the Wyoming Powder River Basin near the northwestern corner of SPP's footprint. Coal accounted for 23% of SPP's installed capacity and 27% of energy generation in 2023. Natural gas-fired generation, the largest by capacity (37% in 2023), is mainly in the south, whereas wind power generation is mainly in the west, nuclear generation near the center, and hydro generation in the north. These factors contribute to a general northwest-to-southeast price split in SPP. Notably, the price split between the two regions was substantially lower in 2023 compared with 2022 and 2021, indicating a decrease in congestion. However, significant congestion was observed in concentrated areas of northwestern and southeastern North Dakota along the MISO seam (SPP Market Monitoring Unit, 2024).

According to NERC (2024c), the transfer capabilities between SPP South and SPP North, SERC Reliability Corporation (SERC) Central and SPP North, and MISO West and SPP North are constrained by transmission limitations during winter peak conditions. Transmission upgrades, as identified in regional plans and made operational in early 2025, are expected to mitigate these constraints. SPP's eastern side, with its higher load and concentration of high-voltage lines, experiences significant congestion, particularly along the southeastern edge, due to historically limited connections between the west and east. In 2023, congestion persisted along the southeastern edge of SPP, from northern Missouri to southern Oklahoma, marking the boundary between intermittent and conventional generation. SPP Market Monitoring Unit (2024) identifies the Charlie Creek-to-Watford City 230 kV line in North Dakota as the transmission constraint with the highest congestion in 2023 and attributes it to the addition of 220 megawatt (MW) of new commercial load.

SPP (2022) finds that the recent buildout of extra-high-voltage transmission infrastructure has facilitated the transfer of zero-dispatch-cost energy from wind generators to load centers, thereby reducing curtailment. SPP's investment in robust transmission expansion from 2015 to 2019 resulted in annual benefits valued at $230 million for its members and customers (SPP, 2022).

Non-RTO/ISO Regions

Non-RTO/ISO regions, including in the Southeast, the West, Alaska, and Hawaii, do not have transparent congestion data. Considering anticipated unprecedented load growth and increasing frequency and severity of severe weather events, regional and interregional congestion across non-RTO regions is expected to increase without additional investments in regional and interregional transmission. For instance, during Winter Storm Elliott, although the central U.S. had abundant wind energy, it could not be used in regions experiencing energy shortages because of insufficient transfer capability (RMI, 2023). On December 2023, SPP curtailed roughly 3 GW of wind, while TVA, which is located in a non-RTO/ISO area in the Southeast, experienced blackouts.

The following subsections present the best available congestion information informed by a new analysis of the Southeast and a literature review for the West and Alaska. Congestion in Hawaii is not discussed because no congestion information is available.

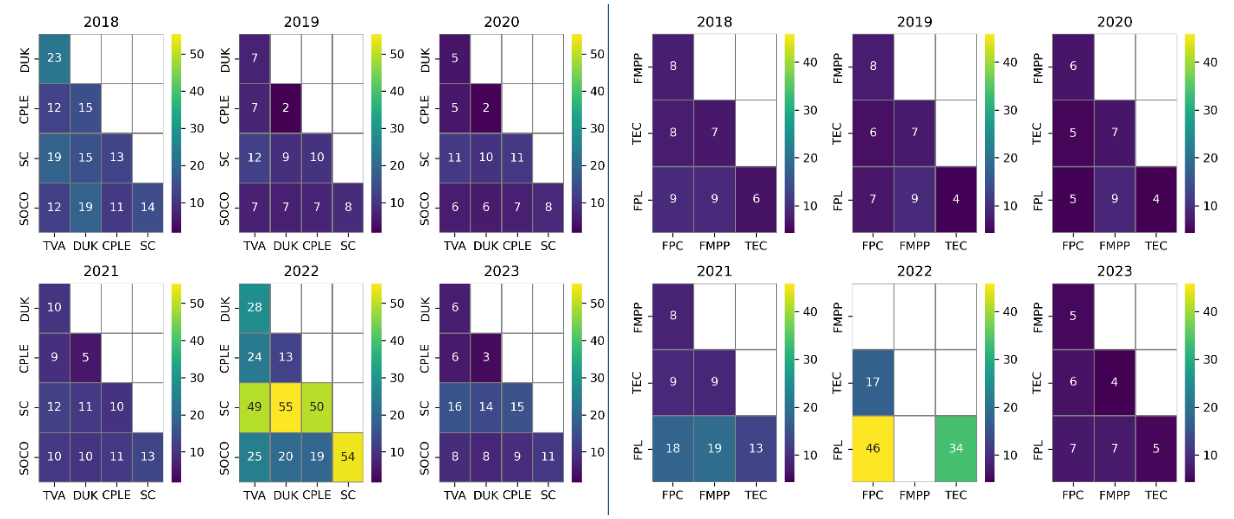
Southeast

The Southeast U.S. does not have an RTO/ISO-operated energy market. In 2022, the SEEM began operations, creating a voluntary 15-minute energy market, but SEEM does not have market clearing prices or locational prices.[40] Transmission constraints did not significantly affect SEEM trading in 2023 and the first quarter of 2024, although transmission constraints may be starting to play a more significant role as is expected from increased network flows (Potomac Economics, 2024a). In 2023, the weighted average monthly price across all segments used in SEEM was approximately $30/MWh. Transfer capacity remains available for SEEM trades, as many of the most used transmission segments have over 90% of their intervals uncleared (Potomac Economics, 2024a).

The lack of publicly available LMP data in the Southeast creates a geographic gap in understanding of transmission congestion and in assessing the potential value of new

[40] SEEM is a voluntary, 15-minute energy market with high-low bid matching and split savings, rather than a uniform clearing price-based auction.

transmission. To address this gap, LBNL (2025d) conducted an analysis of system lambda data in the Southeast from 2012 to 2023. They found the annual average transmission congestion value within SERTP spanned from $2 to $28/MWh, with an average of $12/MWh, and within the FRCC region from $4 to $19/MWh, with an average of $9/MWh (Figure V-8), after excluding transmission value driven by anomalous data. The ranges of transmission value reported here are large, spanning an order of magnitude in some cases. Much of this variation is driven by year-to-year changes, with 2022 having a particularly high intraregional transmission value caused by elevated natural gas prices.



CPLE	Duke Energy Progress East	**FPC**	Duke Energy Florida, Inc.	**SOCO**	Southern Company
DUK	Duke Energy Carolinas	**FPL**	Florida Power & Light Co.	**TEC**	Tampa Electric Company
FMPP	Florida Municipal Power Pool	**SC**	South Carolina Public Service Authority	**TVA**	Tennessee Valley Authority

Source: Lawrence Berkeley National Laboratory (2025d).

Note: The number in each cell represents the transmission congestion value between the two balancing authorities listed on the horizontal and vertical axes. Values in the chart for 2022 associated with South Carolina Public Service Authority and Florida Power & Light were deemed unreliable and are excluded from summary statistics in the paragraph above. The acronyms for each balancing authority are provided in the box at the bottom of the figure.

Figure V-8. Transmission congestion value matrices for SERTP (left) and FRCC (right), 2018–2023.

Estimated LMPs in SERTP, derived through a production cost model of the region from 2016 to 2023, show that the transmission congestion value of intraregional links within SERTP range from $5.89 to $10.07/MWh, with an average of $7.53/MWh (*see* SERTP_Internal in Figure V-4, which is based on the analysis described in Supplemental Materials, *Section V.a. National and Interregional System Congestion and Transfer Capabilities: Visibility into Southeast Transmission Value*). The transmission congestion value for intraregional links in the Southeast is mapped in Figure V-5 for 2022 and 2023.

Both approaches described here—one based on FERC system lambda data and one based on a production cost model—help gain visibility into transmission congestion in the Southeast. Both approaches led to similar long-term average value estimates for intraregional transmission.

Both approaches also showed that transmission values varied significantly by year, with 2022 having the highest transmission congestion value estimates.

West

The Western Interconnection stretches from Western Canada to Mexico and from the Pacific eastward over the Rocky Mountains to the Great Plains, encompassing CAISO along with the non-RTO/ISO NorthernGrid and WestConnect Order 1000 planning regions. Transmission congestion is generally on the rise across the Western Interconnection. Several transmission providers' systems are fully subscribed and congested during a growing number of hours as demand increases, and other factors place more pressure on the grid. Transmission providers in Colorado (Xcel Energy, 2024), Idaho (Idaho Power, 2023 and Avista, 2024a), Montana (NorthWestern, 2023), New Mexico (PNM, 2023), and Utah (Energy Strategies, 2021b) have all indicated a need for system improvements to manage constraints and congestion.

CAISO's *2023 Annual Report on Market Issues and Performance* notes that within the WEIM, the internal congestion pattern typically shifted from south to north during solar production hours to north to south in the evening as solar generation decreased. El Paso Electric and PacifiCorp East BAs were exceptions, experiencing internal congestion that limited flows out of these areas during most hours. In 2023, the frequency of day-ahead export congestion on major interregional interties between CAISO and neighboring balancing areas nearly doubled, primarily because of the Malin intertie connecting CAISO to the Pacific Northwest. Conversely, the frequency of congestion in the import direction declined significantly, resulting in an approximate 75% decrease in both the overall frequency and financial impact of congestion on most interregional interties with CAISO (CAISO, 2024a).

Within the WEIM, total curtailment of wind and solar resources in 2023 rose to 755 gigawatt-hours (GWh), an 18% increase from 2022. February 2023 saw the highest month of downward dispatch at 147 GWh. This significant increase in downward dispatch and curtailment was driven by congestion on internal transmission constraints between Wyoming wind generation and the surrounding system (CAISO, 2024a). Curtailments in CAISO continued to rise through 2024 (EIA, 2025d), demonstrating the increasing effects of transmission capacity constraints.

BAs across the non-RTO/ISO Western Interconnection region identify significant transmission needs to reduce congestion. Examples across the West are listed below.

- NorthWestern Energy's system requires significant improvements to reliably serve its load. The transmission network around Billings, Montana, is severely constrained under peak load conditions, as well as in the Butte and southwestern Montana regions as load in the Butte area grows (NorthWestern, 2023). In addition to using transmission to serve retail customers, Northwestern sells transmission services to a range of other entities who do not receive their supply service from NorthWestern. All these entities compete for available transmission, which is intensifying as in-state generation facilities are shut down and contributing to growing congestion and reduced transfer capacity on NorthWestern's system (NorthWestern, 2023).

- Idaho Power (2023) notes that the majority of the transmission paths connecting Idaho Power to neighboring balancing regions are fully allocated and identifies significant constraints in its core system between the Magic Valley (Midpoint) and the Treasure Valley (Hemingway), which connects two major load centers.
- In Utah, Energy Strategies (2021b) find that Utah's existing system is heavily congested for deliveries into the PacifiCorp East load center, with limited transfer capacity from the north and even lower capacity available from the south.
- NV Energy (2024) identifies limited transmission capacity for transferring energy from generation sites to load centers within Sierra's and Nevada Power's service territories and underscores the need for significant transmission upgrades to enhance import capacity and integrate the anticipated intermittent generation in the region (NV Energy, 2024).
- Avista (2024a) identifies existing system constraints in the Coeur d'Alene, Post Falls, North Spokane, West Plains, and Lewiston areas, attributed to localized load growth.
- According to the Bonneville Power Administration (BPA, 2024), there are severe transmission constraints on the California-Oregon intertie driven by prolonged outages at the Buckley 500 kV substation.
- Portland General Electric (PGE) (2023) highlights that resource portfolios in the Pacific Northwest have expanded because of increasing load growth, new large and highly concentrated loads, and the rapid growth of variable energy resources. Providing reliable service in its territory is challenging without new transmission because BPA's system is fully subscribed.
- Public Service Company of New Mexico (PNM) (2023) notes that the existing transmission system is currently fully subscribed and faces constraints, particularly in delivering power to the northern New Mexico load center and between the southern and northern service territories. These constraints will influence where new generation can be integrated and require additional infrastructure to ensure the deliverability of these resources.

Unlike most of the Eastern Interconnection, congestion in one geographical area of the Western Electricity Coordinating Council (WECC) can have significant interactions with geographically distant systems. For example, when congestion occurs along the West Coast, unscheduled energy from the Northwest flows through Wyoming, Colorado, New Mexico, and Arizona. This energy flow, referred to as loop flow, can create significant congestion and reliability challenges along the eastern edge of the Western Interconnection. In response, the Western Interconnection uses the WIUFMP to manage congestion. The WIUFMP is a FERC-filed tariff administered by SPP that provides a mechanism to mitigate flows on transmission paths with the highest levels of congestion, known as "Qualified Paths," to reliable levels (SPP, 2019). Five of approximately 50 paths in the Western Interconnection are Qualified Paths. Path 66 (California), Path 36 (Wyoming-Colorado), Path 30 (Colorado-Utah), and Path 31 (Southern Colorado-Northern New Mexico) have been qualified since at least 2016 (SPP, 2019). Path 80 (Southeast Montana) was qualified in 2024 (SPP, 2024a). The Qualified Paths are bottlenecks of limited transmission between the Northwest and the highly populated Desert Southwest, including across the West Coast and the eastern side of the Rocky Mountains. The parallel nature of the Qualified Paths creates simultaneous interactions between the eastern and western portions of the Western Interconnection that can lead to reliability risks.

The WIUFMP relies on phase-shifting transformers, referred to as qualified controllable devices, to redistribute the flows and manage unscheduled flows. Phase shifters were a cost-effective alternative to additional transmission for many years, but their effectiveness is decreasing as generation in the WECC transitions away from thermal generators to variable energy resources that are located in different areas on the transmission system and are unable to dispatch upward to manage congestion. With the retirement of thermal generators, reliance on phase shifters is increasing to manage congestion, but phase shifters were not designed to manage the significant changes in transmission flows developing on the system.

The non-RTO/ISO West faces unique challenges because it currently consists of 38 separate BA areas as shown in Figure III-7. BAs are NERC-registered entities subject to strict NERC requirements to balance supply and demand in their respective footprints in real time. They meet these demands through extensive manual coordination with generators and transmission owners/operators within their footprints, along with communications with neighboring BAs and the regional reliability coordinators.

The RTOs/ISOs use a mechanism known as security-constrained economic dispatch to automatically adjust generation outputs in response to real-time system conditions, a base functionality not used by non-RTO/ISO entities. The manual processes used in the non-RTO/ISO West to adjust generation were reasonably effective when net load (total demand minus variable generation) was straightforward to forecast. However, the fragmented BA model is becoming increasingly difficult to manage. This is a significant driver for the development of market alternatives. Automated economic dispatch procedures provided through CAISO's WEIM and SPP's WEIS have partially addressed the difficulties in managing manual coordination between generators and transmission operators for WEIM and WEIS participants in the Western Interconnection. The developing day-ahead markets and RTO expansion are expected to further support congestion management.

Alaska

Alaska's Railbelt power system, extending from southern Alaska, which has significant generation, to Central Alaska, is largely composed of low-voltage, long-distance lines that are outdated, constrained, and lack redundancy. On the southern end, there is a single 115 kV line from Soldotna to Cooper Landing and another 115 kV line from Cooper Landing to Anchorage (AEA, 2023). The system was constructed in 1961 and designed to carry 16 MW of power, less than 15% of the capacity of Bradley Lake Hydroelectric Project, which was added in 1991. Transmission constraints limit both the production of existing resources and the development of future resources in the southern region (AEA, 2023; DOE, 2023a).

The transmission system from central to northern Alaska is similarly weak. The Alaska Intertie, a 170-mile single 138 kV line, connects Willow to Healy and two 138 kV lines connect Healy to Fairbanks. A single 138 kV line connects Fairbanks to Delta Junction (AEA, 2023).

Only 10% or less of peak load can be transferred between regions due to transmission constraints (DOE, 2023a). Therefore, each region along the Railbelt plans for its own capacity needs.

Transmission limitations are also evident in the state's energy costs, which are the most disparate between communities of any state (AEA, 2023). Constraints on the Railbelt system limit the transfer of low-cost energy, resulting in costly fuel use (DOE, 2023a), while access to hydropower and associated transmission lines is a key determinant of energy costs in the Tongass and Chugach National Forests (AEA, 2023).

V.c. Resource Adequacy and Resilience Benefits of Transmission

Interregional transmission can help regions maintain resource adequacy.

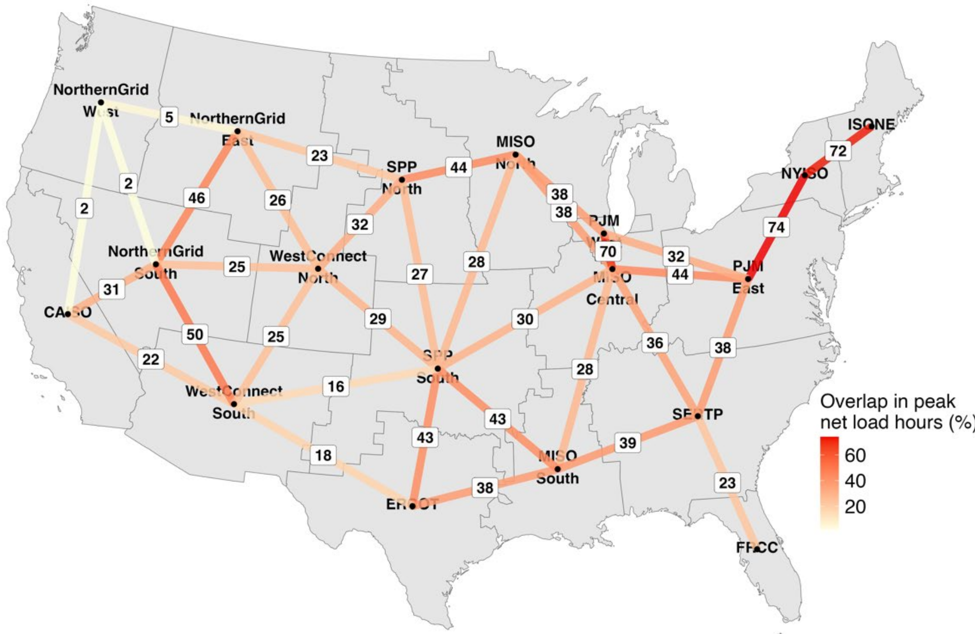
In addition to enabling the exchange of lower-cost electricity throughout the year, interregional transmission can provide additional value during peak and stress periods, which are the hours driving resource adequacy needs. NERC defines resource adequacy as "the ability of supply-side and demand-side resources to meet the aggregate electrical demand (including losses)" (NERC, 2025b). Maintaining resource adequacy requires having sufficient generation available during essentially all hours, which tends to be most difficult when load is relatively high and resource availability is low, or during periods when net load (load minus variable generation) is high (NREL, 2024d). These hours coincide with when the demand for dispatchable generation and storage is the greatest.

Transmission plays a critical role in maintaining resource adequacy by enabling generation to move to where it is needed each hour, which is important both within regions, where generation resources may not be located near major load centers, and between regions that manage varying load profiles and resource mixes.

A recent LBNL study examines the opportunity for interregional transmission to support resource adequacy by trading with neighboring Needs Study regions whose net peak periods occur at different times (LBNL, 2025c). The study examines the 100 highest net load hours and 100 highest priced hours per year between 2016 and 2023. Both the peak net load hours and peak price hours are used as proxies for times when resource adequacy is relatively more difficult to maintain. When one region is experiencing high net load or high prices, it could import power from an adjacent region that is not experiencing tight conditions and improve overall resource adequacy. If high resource adequacy risk periods occur at different times for adjacent regions, interregional transmission can enable bilateral benefits.

The analysis considered the temporal overlap of high net loads and high prices separately. Figure V-9 shows the results for the high net load portion of the analysis. The study found that the Pacific Northwest has hardly any overlap in peak net load hours with adjacent regions (California and two regions in the interior west), driven by the Northwest's tendency to experience peak demands in the winter rather than the summer. On the other hand, the northeastern regions had the greatest overlap in peak net load hours, with NYISO sharing 72% of net peak hours with ISO-NE to the north and 74% of net peak hours with PJM East to the south.

Other regions throughout the contiguous U.S. had moderate overlap in net peak hours with their neighbors. Nearly all other pairs of neighboring regions experienced an overlap of between 16% and 50% in net peak hours.



Source: Lawrence Berkeley National Laboratory (2025c).

Figure V-9. Average percent overlap of peak net load hours between adjacent planning regions.

While this analysis shows why interregional transmission can provide resource adequacy value, the analysis cannot determine how much interregional transmission would be optimal, or if more capability would be needed.[41] In particular, the consideration of net loads on a region-by-region basis does not reflect the capacity of existing interregional transmission to deliver power to neighboring regions during their periods of highest net load.

The second portion of the LBNL study examines periods with the highest prices. During each region's peak price hours, the mean price percentile in adjacent regions was used to assess their degree of stress. The use of price percentiles removes the effects of varying electricity market rules and price caps. The results are shown below in Figure V-10. The central part of the country had some of the lowest peak price correlations between neighboring regions. Many regions across NorthernGrid, WestConnect, SPP, and ERCOT exhibited mean prices in approximately the 50th to 70th percentile during the highest price periods of adjacent regions. For example, WestConnect South's mean price during SPP South's and ERCOT's peak price periods was only in the 53rd and 55th percentile, respectively. Unlike net load, prices reflect the impact of imports and exports that are enabled by the existing interregional transmission system.

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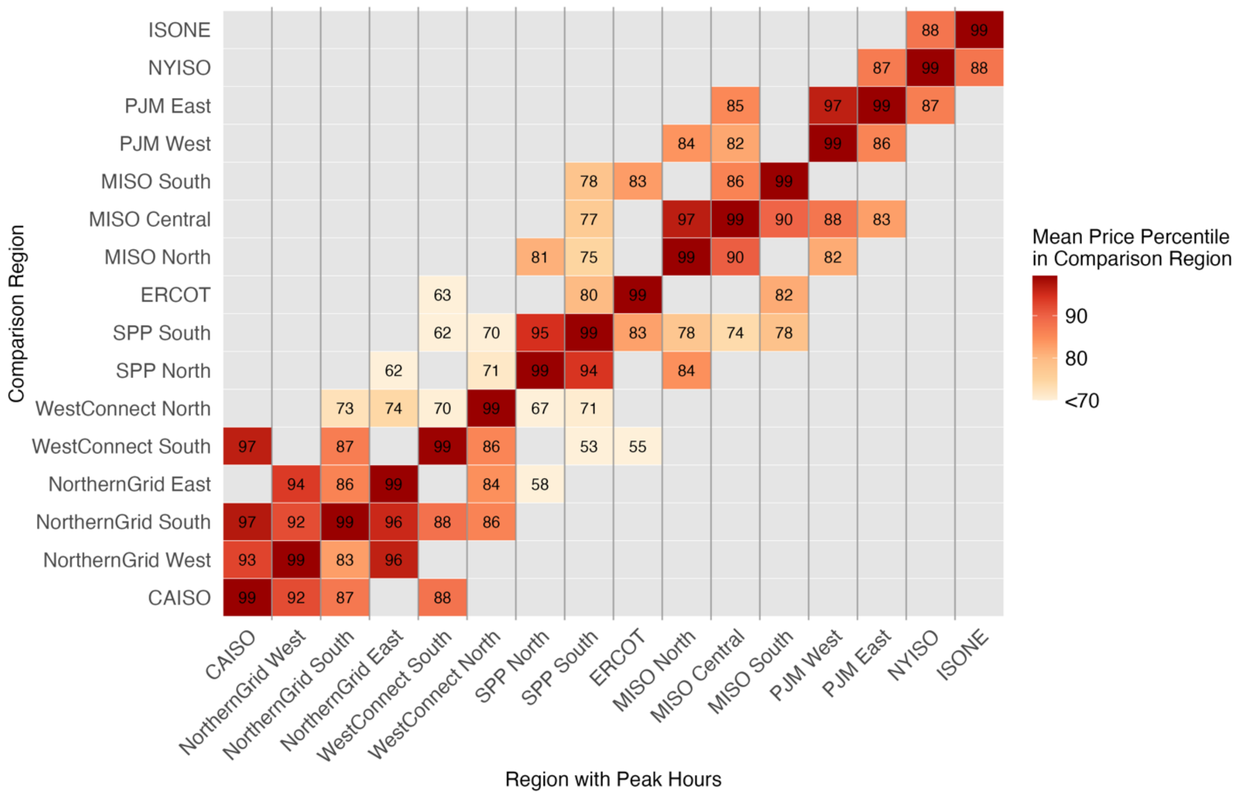
[41] Chapter VII of the Needs Study discusses NERC's Interregional Transfer Capability Study, which focuses on the need for increased interregional transfer capability.

As such, low overlap of high price periods suggests there would be potential resource adequacy value associated with increasing interregional transmission capacity.



Source: Lawrence Berkeley National Laboratory (2025c).

Note: The figure should be read by column, with each column analyzing the peak price hours of the region listed along the bottom. Each row shows what percentile rank of their own net load other regions experience during those same hours, on average. Only adjacent regions are shown.

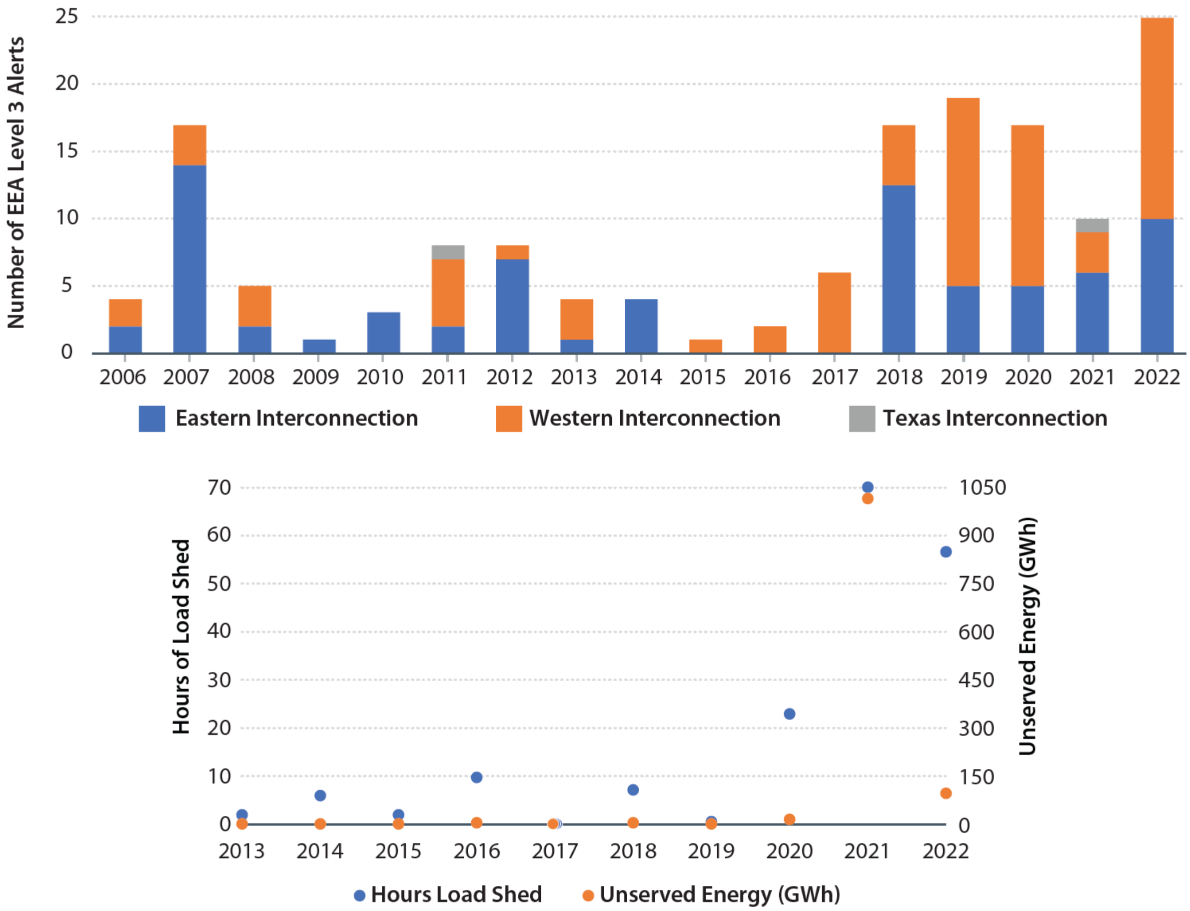
Figure V-10. Average price rank during x-region's peak (annual top 100) price hours.

Emergency events demonstrate the limits of today's transmission system.

The bulk power system faces challenges from rising demand, changing weather patterns, evolving operating characteristics, and increasing security threats. Severe weather events are becoming increasingly frequent and severe (NERC, 2025a). Additionally, instances of cyber and physical attacks on the grid are increasing. Power systems must be prepared to withstand and recover from increasingly severe and widespread disruptions. Addressing these challenges requires a combination of grid modernization, resource diversification, and enhanced interregional coordination.

Firm load interruptions, or load shedding, are controlled, unplanned interruptions of firm demand (demand that the power supplier is obligated to provide) in response to grid emergencies. Reliability coordinators can declare Energy Emergency Alerts (EEAs) to direct BAs to conduct different actions. There are three levels of EEAs. Level 3 EEA is the most severe and occurs when firm load interruptions are imminent or in progress (NERC, 2025a). Trends in declaring Level 3 EEAs can reveal capacity, energy, and transmission insufficiencies.

Figure V-11 shows the historical frequency of Level 3 EEAs in North America, from 2006 to 2022, and the duration of load shed and estimated amount of unserved energy during these events. In recent years, severe weather events have driven an increase in Level 3 alerts, duration of load shed, and amount of unserved energy. In 2020, there were 22.4 hours of operator-initiated load shed driven by Hurricane Laura as well as wildfires and heat waves in California. This number increased to 70.5 hours in 2021 due to Winter Storm Uri and 56.5 hours in 2022 due to Winter Storm Elliott and a heat wave in June (NREL, 2024e). In 2023, there were 16 Level 3 EEA alerts issued, all of which were triggered by reduced generation or import capacity during periods of high load, and none of which resulted in the shedding of firm load (NERC, 2024b).



Source: National Renewable Energy Laboratory (2024c).

Figure V-11. Nationwide Level 3 EEAs (top) and unserved energy (bottom).

A February 2023 winter storm in ERCOT affected 48,761 megavolt-amperes (MVA) of transmission capacity, the most of any single weather event across the country that year (NERC, 2024b). On January 16, 2024, in Texas, the winter peak load of 78.5 GW broke the previous winter record of 78.3 GW set on December 23, 2022 (Potomac Economics, 2024c). Potomac Economics (2024c) expects reliability concerns resulting from winter peak demands will become more frequent. In 2024, the Atlantic Coast experienced an unusually active hurricane season, resulting in widespread power outages. Notably, Hurricane Beryl, a Category 1 storm, led to over 2.7 million electricity outages in Texas at its peak on July 8 (FERC, 2025).

The transmission system needs to be expanded and hardened to respond to these events (National Wildlife Federation, 2023). NERC (2023) finds that the development of well-placed and highly resilient transmission infrastructure is not keeping pace with system changes and cites the need for more strategic transmission deployment, both in terms of location and design. NERC (2023) recommends that Electric Reliability Organization Enterprise, which includes NERC and the six regional entities, accelerate the development of transmission infrastructure with these risks in mind, adding redundancy and diversity to harden the system against anticipated threats.

In 2024, CAISO completed 2,000 circuit-miles of reliability-driven transmission projects, more than any other RTO/ISO (FERC, 2025). The majority of these projects address reliability concerns or harden the system against severe weather and fire threats. Reliability in California is increasingly influenced by variable weather events attributed to climate change. If severe heat waves coincide with other climate-related issues like drought or wildfire, the state’s electricity grid could face challenges beyond what the system has historically been planned to withstand. In 2020, a heat wave across the western states caused rotating outages that stemmed from a 500 MW electricity shortage. In 2021, the Bootleg wildfire in Oregon impacted the California-Oregon intertie, which resulted in a loss of 3,000 MW of imports into California and led CAISO to issue an EEA requesting energy conservation measures. In September 2022, record high temperatures led to a new peak load record of 52,061 MW, nearly 2,000 MW higher than the previous record, despite significant efforts to reduce demand during this peak period (CEC, 2024). NERC (2024d) reports that during this heat wave, California North experienced resource deficiencies for 17 hours over four days.

California relies heavily on imported electricity, especially in the evenings, with about 29% of its electricity needs met through imports. The California Energy Commission (CEC) *California Energy Resource and Reliability Outlook*, *2025* reports that imports via interregional lines in the WEIM played a crucial role in maintaining CAISO’s reliability during the September 2022 heat wave (CEC, 2025). A widespread heat event across the western region would pose a reliability threat to California, reducing available electricity imports from neighboring balancing regions when most needed. Furthermore, critical northwestern hydroelectric import paths run through fire-prone areas in Oregon. All transmission import paths, most in-state transmission lines, in-state hydroelectric resources, and geothermal generators cross areas with severe or elevated fire threats, as defined by the California Public Utilities Commission and the California Department of Forestry and Fire Protection.

In NorthernGrid West, the Pacific Northwest Utilities Conference Committee (PNUCC, 2024) underscores that the multiday cold snap in January 2024 severely tested the Pacific Northwest's energy system, bringing it perilously close to an inadequate supply. From January 12 to 16, 2024, the region experienced severe weather. Freezing temperatures were initially lower on the westside than the eastside, causing BAs to encounter system peaks at different times. Had temperatures dropped simultaneously across the region, the demand could have been significantly greater. To maintain reliability amid high demand and low water conditions, the Pacific Northwest relied heavily on energy imports from the Desert Southwest and Rocky Mountain regions. Constraints in the natural gas system further reduced fuel supplies to gas-fired power plants, affecting capacity and forcing some utilities to depend more on imports. The Western Power Pool (WPP), the program administrator for the Western Resource Adequacy Program (a regional reliability, planning, and compliance program), assessed the event and found that peak load was near or exceeding historical peaks in many areas. WPP emphasized the value of a resource adequacy program with a broad geographic footprint and diverse load and resources. The study concludes that a more connected grid would provide access to a wider range of resources and facilitate the sharing of energy over larger distances. This would help balance fluctuations in demand and supply while enhancing the resilience of the grid. Additionally, to ensure resource adequacy, the region is pursuing solutions such as extending the usefulness of existing infrastructure by converting coal plants to natural gas plants, ensuring a stable natural gas supply to run these plants, and exploring emerging technologies.

Avista (2024a) identifies that the concentration of resources in a limited number of locations within its small service area, particularly at Noxon Rapids and Cabinet Gorge, presents significant risks to the system resilience. To address these concerns, Avista has implemented multiple transmission pathways to facilitate the transfer of energy from these resource locations to load centers, thereby aiming to mitigate wildfire risks.

In WestConnect South, Salt River Project (SRP, 2023) highlights that given the utility's connection to an extensive grid system that includes neighboring utilities, the entire regional grid is at risk when any area or utility lacks adequate resources. Severe temperatures exacerbate this risk by increasing customer demand for energy and fueling natural disasters such as wildfires, which can damage the transmission system and hinder utilities' ability to deliver power to their customers.

In a review of severe weather events affecting PNM's customers, PNM (2023) highlights the February 2011 freeze-off, the February 2021 cold snap, and the August 2020 western heat wave. Both winter peak events led to stressed grid conditions that were due to subfreezing temperatures and that resulted in the curtailment of gas generation and power outages for thousands of customers. The impacts of the February 2011 freeze-off were severe, affecting 21,000 PNM customers. The August 2020 heat wave caused a surge in electric demand across the Western Interconnection. The most severe effects were felt in California, where rolling blackouts were implemented for the first time since the 2001 energy crisis. Utilities throughout the West experienced tight supply conditions and widespread EEAs. Between August 14 and 17, PNM managed to balance the system without market support, but a large thermal generator outage on August 17 stretched PNM's remaining resources to their limits. During net peak periods, western bilateral markets were illiquid, and PNM could not procure additional supplies despite offering high prices. Weather-induced outages affected generators and transmission lines, and gas supply was constrained.

In 2021 and 2022, the central U.S. endured several historic winter storms that resulted in record low temperatures and unprecedented electricity demand. These conditions severely tested the flexibility of the overall bulk electric system.

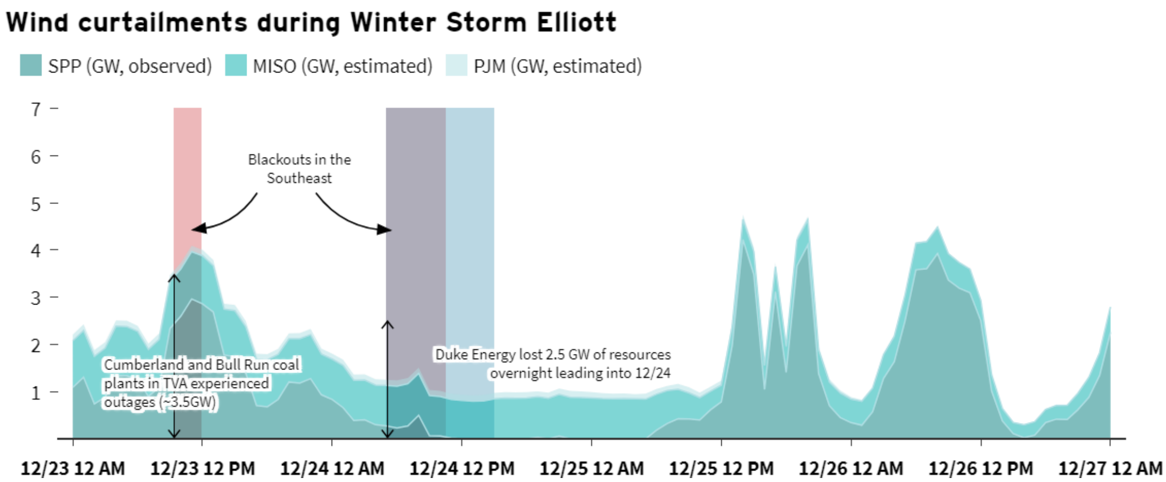
Winter Storm Uri was a multiday event that stressed the grid with low temperatures extending from the Canadian border to the Texas panhandle. Prolonged cold temperatures resulted in significant energy usage, fuel availability issues, and impacts on transmission and generation facilities, culminating in the first RTO-directed load shed in the history of SPP. MISO also faced reliability challenges during Winter Storm Uri, as it worked to meet high loads amid high levels of generator and transmission line outages, as well as overloaded lines. While MISO had adequate supply, transmission constraints prevented power from moving to where it was needed. At one point during the event, PJM was exporting 13 GW into MISO. MISO's transmission system also supported neighboring systems, particularly as power flowed eastward through MISO to support SPP. MISO was able to limit the storm's impact to a 2-hour regional emergency load reduction and several local events, which MISO (2021a) attributes to several factors, including its extensive transmission system.

Disadvantaged communities are often most affected by outages (DOE, 2024a). Deploying advanced grid technologies in disadvantaged communities can improve reliability, resilience, and energy independence, while enhancing equitable grid planning and investment decisions. Pacific Northwest National Laboratory (PNNL, 2023) cite a study finding that high-minority populations were four times more likely to lose power than majority-white areas during Winter Storm Uri in Texas, controlling for factors like income and critical infrastructure. PNNL (2023) emphasize the need for equity in load shedding strategies and the need for restoration and distributed generation to manage the impacts of such events. Grid hardening and advanced grid solutions will be critical for upgrading the grid to meet modern demands.

Shortly after Uri, Winter Storm Elliott hit in December 2022, challenging SPP, MISO, and the Southeast. Although Elliott was of shorter duration, it still heavily stressed the SPP system. Higher wind levels during this storm led to more severe wind chills and, consequently, higher heating loads (FERC et al., 2023). Additionally, the increased wind forecast caused greater congestion moving from west to east into Missouri. This increased congestion, along with facility outages, prompted one of SPP's member companies to mitigate low voltages on their systems through transmission operator-directed load shedding (SPP, 2025b). Informed by lessons learned in Winter Storm Uri, MISO was better prepared for Winter Storm Elliot. During this event, MISO had sufficient capacity to meet demand and support neighboring systems (MISO, 2023b). MISO supplied SERTP with 1.1 GW, TVA with 1.1 GW, Associated Electric Cooperative with 1 GW, and SPP with 0.5 GW. However, high loads, unit failures in the South, and transmission congestion led MISO to declare a "Maximum Generation Event" to access demand response, alleviate conditions, and continue exporting to neighboring systems. Additionally, two local transmission emergencies were declared in Wisconsin and Missouri to manage severe congestion.

The SERC region is vulnerable to severe weather conditions that threaten the reliability of the bulk power system, including cold snaps, heat waves, tornadoes, and tropical storms.

During Winter Storm Elliott, the Southeast experienced near-record low temperatures. Electricity demand surged as power plants failed due to equipment failures and natural gas disruptions, leading to rolling blackouts and power price spikes (ACORE, 2023). RMI (2023) explains that if TVA, Duke Energy, and other regions were not able to import power during the event, blackouts would have been significantly more widespread. However, insufficient transmission capabilities limited resource sharing between the Southeast and neighboring systems during the event. As shown in Figure V-12, as the Southeast experienced blackouts, wind was curtailed in SPP, MISO, and PJM (RMI, 2023). If transmission capacity were available during this time, the excess energy in neighboring systems could have been transferred to the Southeast, reducing the duration and magnitude of blackouts. ACORE (2023) find that modest investments in interregional transmission capacity would have saved the region nearly $100 million over the 5-day storm. Additional ties would also allow the Southeast to export power when neighboring systems are facing weather events. ACORE (2023) explain that during Winter Storm Uri of 2021, which primarily affected the central United States, expanded ties between the Southeast and Texas could have prevented outages in Texas.

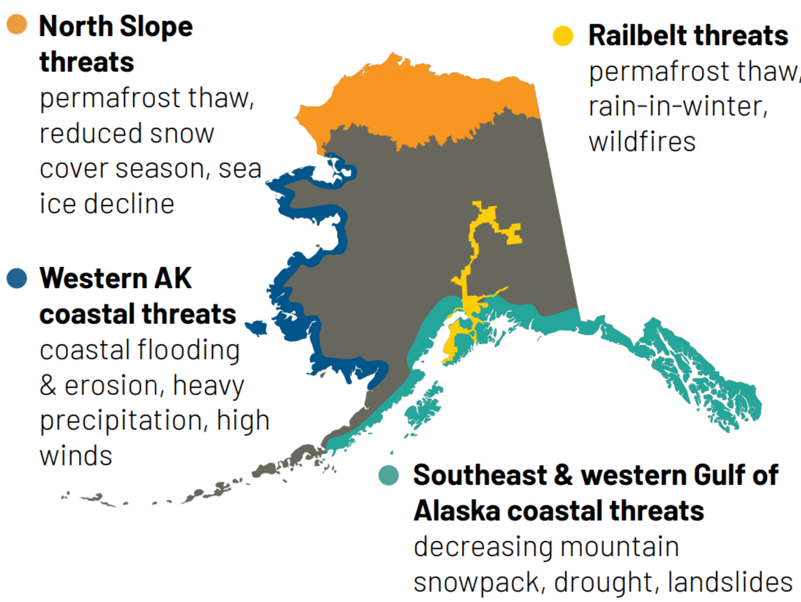


Source: RMI (2023).

Note: All times are in Central Standard Time. SPP reports the amount of wind curtailed in its footprint, while MISO and PJM do not explicitly do so. To estimate the amount of wind curtailed in MISO and PJM, the 2021 annual average curtailment rate from LBNL's "Land-Based Wind Market Report: 2022 Edition" was applied to the reported hourly wind generation profile in the two regions. TVA's periods of rolling blackouts are in red, while Duke Energy's outage period is in blue (purple indicates overlap).

Figure V-12. Wind curtailments during Winter Storm Elliott.

Alaska's transmission infrastructure must be resilient to harsh environmental threats. The Railbelt traverses subarctic mountainous terrain and the strong currents of the Cook Inlet, through a region that is vulnerable to volcanic eruptions, forest fires, flooding, and winter storms (DOE, 2023a). Figure V-13 summarizes climate threats in regions of Alaska with greatest energy need. University of Alaska Fairbanks (2023) urge that future infrastructure development in the state take Arctic environmental change into account in all decision-making, stating that specialized adaptation techniques will be required to ensure resilience.



Source: The University of Alaska Fairbanks (2023).

Figure V-13. Climate threats by energy regions in Alaska.

Hawaii faces increasing threats of hurricanes, tsunamis, wildfires, lava flows, and earthquakes. The state's isolation and topography amplify these risks. Much of the state's electric infrastructure traverses isolated and rugged terrain, making upgrades and maintenance difficult (Hawaiian Electric, 2023). If a hurricane were to hit the current grid, Hawaiian Electric anticipates outages would last for many weeks to many months. Hawaii's grid needs preventive measures, like system hardening, and mitigation solutions to increase resilience. Preventive measures can reduce the likelihood and impact of damage to grid assets, however these measures can be costly and slow to implement, so mitigation efforts can address localized concerns in the meantime (Hawaiian Electric, 2023). To harden the grid against wildfire threats, Hawaiian Electric has started installing fire mesh and applying fire paint to poles in high-risk areas.

Limited transmission connections affect reliability in Alaska and Hawaii.

Geographic isolation presents unique challenges to reliability, particularly in regions where communities are dispersed, infrastructure is aging, and redundancy is limited. For remote and islanded systems, lack of transmission can leave populations vulnerable to outages, natural disasters, and system disturbances. Strengthening transmission networks in these areas is essential to enhancing reliability.

Alaska's energy system is composed of over 150 microgrids to serve its dispersed and remote population (University of Alaska Fairbanks, 2023). Most of Alaska's Railbelt transmission system, which serves more than 75% of the state's population, is more than 40 years old and in urgent need of expansion and modernization (DOE, 2023a; AEA, 2024). The Railbelt system connects five utilities from the Kenai peninsula to Fairbanks (AEA, 2023). For the most part, these lines lack redundancy (AEA, 2023). The single transmission line connecting southern and central Alaska was not designed to handle the volume of transfers required today

(DOE, 2023a). Given the lack of redundancy, many cities and regions are at risk of being isolated from energy sources in the case of an event or scheduled outage (AEA, 2024). Alaska Energy Authority (AEA) reports that the 2019 Swan Lake fire led to 135 days in which the southern generation was separated from the rest of the Railbelt (DOE, 2023a). Additionally, construction outages regularly disrupt service (DOE, 2023a). AEA (2023) states that Alaska's transmission infrastructure is insufficient to provide reliable, redundant, and affordable power distribution to the Railbelt. AEA (2023) emphasizes the need for a modern, integrated grid, incorporating N-1 contingencies to ensure reliability.

There are multiple metrics indicating that the Railbelt is facing reliability challenges. Firstly, the frequency regulation has declined. DOE (2023a) cites a study at Chugach that finds that system frequency was at the nominal 60 Hz about 44% of the time in 2011 and only about 15% in 2020. Deviation from the design frequency can cause considerable damage. Additionally, the Alaska Railbelt Reliability Standards require that the system be able to handle the failure of any one generation unit without resorting to load shedding, however DOE (2023a) explains that this is increasingly challenging without fast response spinning reserve from gas-fired generation. For reference, fast response spinning reserve is a type of operating reserve with the ability to ramp up its output within minutes to meet a sudden increase in demand or to compensate for the loss of generation supply. Lastly, the stability limit of the single transmission line connecting southern and central Alaska is only 50% of the line's thermal rating in one direction and 30% in the other, meaning connection between the regions is not strong enough to maintain stable operating conditions.

Hawaii has six independent power grids, one for each of its main islands. There are no interties connecting the islands or connecting the state to mainland infrastructure. Upgrades are needed to accommodate a shifting resource mix and integrate demand response, distributed generation, and electric transportation, as well as to manage environmental, cyber, and physical threats.

In Hawaii, five of the six island power grids (excluding Kauai) are operated by Hawaiian Electric. In the face of aging infrastructure and climate change, Hawaiian Electric warns that customers are at risk of frequent outages if action is not taken to upgrade the transmission system (Hawaiian Electric, 2023). The Kauaʻi Island Utility Cooperative (KIUC), which serves Kauai, anticipates reliability challenges, including cybersecurity threats, climate change impacts, and natural disasters such as hurricanes and floods (KIUC, 2023). KIUC states that ideally it should have at least two transmission lines serving all portions of the island to avoid unnecessary outages (KIUC, 2023). KIUC plans to pursue significant transmission investments in the coming years to improve the reliability of the North Shore, which currently faces reliability challenges due to its remote location and outages associated with the existing single transmission line.

VI. Future Needs Assessment through Review of Regional Planning Reports

Given the lengthy timelines associated with transmission development, the nation's transmission needs must be defined not only by current demands but also by anticipated future requirements. Congress has specifically instructed the Department to factor in expected future transmission congestion and other needs as part of this comprehensive study. In response, this chapter reviews literature from regional planning entities, followed by a closer look at the drivers of future transmission development. These drivers are derived from a review of regional reports and further supplemented with additional analysis from related literature.

The key findings from this chapter include:

- Load growth is the main driver of transmission need, adding pressure to peak demand. Transmission investments are therefore critical to ensure grid reliability.
- Given resource changes, additional transmission will be needed to maintain reliability. Additional factors driving the need for transmission include aging infrastructure, resource retirements, and new generator interconnections.
- Regional planning processes indicate that regions are investing substantially in new transmission. Some regions approved their largest transmission planning portfolios in recent years.
- Interregional transmission is increasingly recognized for its contributions in increasing reliability, grid resilience, and meeting demand growth in at-risk areas. Several planning regions have initiated joint planning processes to better identify interregional transmission and have already identified significant risk if transfer capacity is not increased between certain regions.
- The transmission needs on Tribal lands vary significantly across the regions. Some require improved energy access and reduced costs, whereas others seek opportunities for utility-scale energy development. National studies identify the need for new transmission development on and near Tribal lands, recommending that strategies be developed aligning new transmission development with Tribal needs and goals.

VI.d. Regional Transmission Planning and Coordination

RTOs/ISOs, utilities, and other planning entities conduct short- and long-term studies to identify transmission needs for their respective regions. Although each region faces unique geographic challenges, planning entities, in general, identify transmission projects that will facilitate the integration of new generating resources, improve system reliability, and reduce the cost of congestion. Additionally, individual Tribal nations express a wide array of energy needs and goals that would benefit from analysis and support specifically focused on Tribal lands to better understand opportunities for transmission development.

CAISO

CAISO conducts its transmission planning process on an annual basis with collaboration and input from the California Public Utilities Commission and the CEC. In the *2023–2024 Transmission Plan*, CAISO recommended 26 new transmission projects representing a total investment of $6.1 billion. Driven by load growth and electrification, 19 of those projects are to meet reliability needs with estimated costs up to $1.54 billion (CAISO, 2024b). Of these projects, 14 are located in PG&E, four in SCE, and one in SDG&E.[42] The reliability needs identified in the CAISO *2023–2024 Transmission Plan* (2024b) primarily include projects aimed at alleviating thermal overloads in regions experiencing increased demand, such as the Greater Bay Area, Oakland, Salinas, and Sacramento.

CAISO's *2024–2025 Transmission Plan* recommends the Greater Bay Area 500 kV Transmission Reinforcement project as essential for supporting the increased supply needs in the San Francisco Bay Area. New high-voltage lines spanning significant distances are also recommended to access out-of-state resources in New Mexico, Wyoming, and Idaho. In its 2024–2025 planning cycle, CAISO has determined a need for 31 transmission projects, representing a total infrastructure investment of approximately $4.8 billion (CAISO, 2025).

CAISO also conducts a *20-Year Transmission Outlook* (2024c) to project long-term transmission needs. This 20-year outlook published in 2024 estimates that an investment of $45.8–$63.2 billion will be required over the next two decades for transmission development to reliably serve California's load, a 50%–100% increase from the $30.5 billion projected in the previous outlook published only two years prior in 2022 (CAISO, 2024c).

ERCOT

Across the ERCOT system, almost $12 billion of future transmission improvement projects are expected to be put into service between 2024 and 2030 (ERCOT, 2023). ERCOT's *2024 Regional Transmission Plan* outlines options to develop new transmission from 2026 to 2030 to address statewide reliability needs and serve large load interconnection across the region. The *2024 Regional Transmission Plan* includes two options for ERCOT's Strategic Transmission Expansion Plan—a 345 kV plan and a 765 kV backbone plan (ERCOT, 2024b). In 2030, the region anticipates a need for two new double-circuit 345 kV import paths, one from North/Central Texas and one from South Texas (ERCOT, 2024c). Additionally, the region is planning for multiple additional high-voltage import paths and a short path from the Panhandle in 2038. Most notably, major enhancements are needed to the import pathways to both Central Texas and South Dallas, primarily to deliver imports from the Coast

[42] CAISO (2024b) also observes overloads on most of the 115 kV lines serving the Oakland area due to increases in the load forecast, which the previously approved Oakland Clean Energy Initiative is not sufficient to support. While the Oakland Clean Energy Initiative project moves forward, CAISO will continue assessing alternatives for reinforcement in the 2024–2025 transmission planning process. More information can be found at https://stakeholdercenter.caiso.com/InitiativeDocuments/Draft-Addendum1-2023-2024-Transmission-Plan.pdf.

Weather Zone. One of the main drivers of these increases is the rising electricity demand, which is attributed to increased oil and gas development (ERCOT, 2024b).

ERCOT (2024c) developed multiple transmission options to serve significant projected load growth in the Permian Basin in West Texas through 2038. Each option included over $10 billion of transmission upgrades spanning more than 1,000 miles of new transmission rights-of-way. In 2025, the Public Utility Commission of Texas approved the 765 kV extra-high-voltage transmission option to address reliability and load growth in the Permian Basin (PUCT, 2025).

Lastly, two noteworthy, proposed interregional direct current transmission lines could substantially increase transfer capability between ERCOT and neighboring regions (NERC, 2024c). Southern Spirit Transmission—selected through the second round of capacity contracts of DOE's Transmission Facilitation Program (40106)—would enable transfers between Eastern Texas and MISO South, and the Pecos West Intertie would connect Western Texas with the Western Interconnection.

DOE Work on Transmission Financing

The Department's Transmission Facilitation Program—authorized by IIJA section 40106—is an innovative revolving fund program that will help overcome the financial hurdles facing large-scale new transmission lines, upgrades of existing transmission lines, and the connection of microgrids to existing infrastructure corridors in Alaska, Hawaii, and U.S. territories.

Department of Energy, Transmission Facilitation Program (40106), at https://www.energy.gov/gdo/transmission-facilitation-program.

Texas Reliability Entity (Texas RE) (2024) identifies weatherization of transmission resources (a deficiency seen during Winter Storm Uri) as a top priority for maintaining the reliability of Texas's grid. Given the state's location on the Gulf Coast, tropical cyclones present a growing risk to its power grid, especially as the frequency and intensity of severe storms are expected to increase (Nature Energy, 2024). Harris County (where Houston is located) is the most vulnerable to tropical cyclones, given its location and large population (Nature Energy, 2024). Nature Energy (2024) conclude that hardening just 1% of critical transmission lines can reduce the likelihood of the most destructive type of outage by 5 to 20 times.

In addition to weather events, ERCOT experienced a significant increase in physical intrusions and damage reports in 2023 relative to previous years (Texas RE, 2024). Furthermore, significant load growth, new operational challenges associated with the integration of intermittents, and the growing risk of natural disasters have further challenged the region. Despite these challenges, ERCOT continues to demonstrate adequate reliability for normal operating conditions and under transmission contingencies (Texas RE, 2024).

ISO-NE

As of June 2023, ISO-NE had anticipated $1.5 billion investment in proposed, planned, or under-construction reliability transmission upgrades expected to be online by 2027 (ISO-NE, 2023). Part of the investment portfolio includes the New England Clean Energy Connect project, a 1,200 MW high-voltage direct current (HVDC) line connecting Québec to New England and is in service as of January 2026 (ISO-NE, 2025b). Additionally, the region had $4.3 billion of estimated investment through 2030 to repair and replace aging transmission assets (ISO-NE, 2023).

ISO-NE (2023) finds that one of the most critical issues facing the transmission system is the potential loss of legacy distributed energy resources during transmission system faults because they are not able to "ride through" disturbances. Additionally, increased solar penetration will demand more ramping, reserves, and voltage support to manage power flow from the distribution system onto the transmission system when solar production is high (ISO-NE, 2023).

ISO-NE is conducting its third *Maine Resource Integration Study* to identify transmission upgrades needed to interconnect 1,200 MW of new generation resources in Northern Maine. Its study results indicate a transmission upgrade approach that would include new 345 kV transmission facilities between southern and northern Maine (ISO-NE, 2024b).

In the longer term, ISO-NE's *2050 Transmission Study* (ISO-NE, 2024a) finds that decreasing ISO-NE's peak load significantly reduces the cost of necessary transmission expansion. Transmission expansion costs are estimated to be nearly $25 billion with a 2050 peak load of 57 GW but would drop to $15 billion if the peak load can be managed down to 51 GW. Possible future transmission solutions were developed within this study to serve as conceptual roadmaps for transmission expansion from 2035 to 2050 to meet peak demand scenarios of 51 and 57 GW (ISO-NE, 2024a).

MISO

To meet accelerated load growth in the region, MISO's *Long Range Transmission Plan* (LRTP) Tranche 1 portfolio approved in July 2022 includes 18 projects expected to be in service between 2028 through 2030[43] across the MISO Midwest subregion, totaling $10.3 billion in transmission investments (MISO, 2024). Further, MISO's local, Tranche 2.1, and JTIQ portfolios include 488 new projects totaling $30 billion (MISO, 2024). The 2024 MISO Transmission Expansion Plan approved five of the seven identified projects in the MISO-SPP *JTIQ Study*, conducted to address barriers to the development of new generation along the MISO-SPP seam (MISO, 2024). The projects are expected to enable a total of 28.6 GW of additional generation for a total cost of $1.65 billion (FERC, 2025).

[43] More information on the Tranche 1 portfolio can be found at https://view.officeapps.live.com/op/view.aspx?src=https%3A%2F%2Fcdn.misoenergy.org%2FLRTP%2520Tranche%25201%2520Appendix%2520A-4%2520Schedule%252026A%2520Indicative625788.xlsx&wdOrigin=BROWSELINK.

Additionally, MISO (2024) identifies 36 local baseline reliability projects, totaling $1.1 billion of investment, and 310 projects classified as “Other,” the majority of which address localized reliability issues that are due to load-serving needs and aging transmission infrastructure.

MISO (2021a) warns that events similar to Winter Storm Uri are likely to challenge system reliability in the future, especially given anticipated increases in intermittent resources and severe weather events, and asserts that transmission, both within MISO’s footprint and across its boundaries, is critical for maintaining reliability. MISO (2021a) states that it will build on the LRTP process to identify intra- and interregional solutions to improve reliability, particularly to evaluate north-south transfer capability, which would have helped during the event.

In 2024, MISO retired 3.6 GW of capacity, more than any other RTO/ISO (FERC, 2025). MISO’s *Renewable Integration Impact Assessment* (RIIA) finds current transmission infrastructure to be insufficient to deliver energy to load as intermittent penetration increases (particularly beyond 30% of annual load) (MISO, 2021b). This insufficiency is especially pronounced if generation is concentrated in different regions of the footprint than the load it intends to serve, which is likely given the non-uniform resource quality, differing intermittent preferences, and differing regulatory environments across MISO.

MISO conducts 10-year and 20-year regional reliability analyses that point to the need for significant transmission system enhancements across MISO to address many of the grid issues forecasted in the RIIA (MISO, 2024). MISO explains that enabling resources in MISO North will increase regional transfers into and through MISO Central (MISO, 2024). Additionally, changes in the resource mix will require increased transfers into and from Michigan, as the state exports excess solar resources during the day and imports generation during nighttime hours.

NYISO

NYISO (2024a) recommends several opportunities to expand the transmission system efficiently and cost-effectively to address anticipated future constraints, including monitoring bulk transmission expansion opportunities in Western and Northern New York and installing dynamic reactive power support to maintain Central East Interface voltage performance.

NYISO (2023) finds that while the system is projected to meet all reliability criteria from 2026 through 2032 under normal weather conditions, reliability margins are narrowing and there are several risks for long-term reliability. New York’s Climate Leadership and Community Protection Act was passed in 2019 and sets a target of 70% renewable energy by 2030 and a zero-emissions grid by 2040. Since its passing, twice as much generation has been deactivated as has been added to the system, which poses a significant reliability risk if this trend continues (NYISO, 2023). Furthermore, the resources being added to the system do not offer as much energy or capacity during peak winter conditions as the fossil fuel resources they are replacing (NYISO, 2024c). If generation and transmission additions do not keep pace with load growth, available energy margins in the state will decrease. Under large load projections or sustained heat waves, New York could approach a deficiency in 2030 (NYISO, 2023).

NYISO (2024c) notes that historically, reliability needs were largely driven by transmission constraints. However, the *2024 Reliability Needs Assessment* (RNA) observes narrowing resource adequacy, statewide system margin, and transmission security margins. In 2034, NYISO (2024c) projects transmission overloads that will be due to insufficient statewide generation reserves rather than specific transmission constraints. Low levels of reserve restrict the system's ability to resolve overloads through redispatch. The study finds that approximately 75 MW of additional generation are needed to fully resolve winter overloads (NYISO, 2024c).

In particular, NYISO (2023) identified a reliability need in New York City that was to begin in the summer of 2025 and would be driven by increased peak demand and the New York State Department of Environmental Conservation's Peaker Rule, which aims to phase out small natural gas peaker plants by the end of 2030. NYISO's most recent annual forecast discussed in its annual grid and markets report, 2025 Power Trends, shows slower adoption rates for electrification technologies and therefore 200 MW less demand, which is enough to eliminate this reliability need identified in the 2024 RNA (NYISO, 2025). However, the changing supply and demand mix along with narrow reliability margins could affect reliability needs in the future.

NYISO's grid may not be prepared to manage severe weather conditions, such as heat waves or storms, which could cause demand surges and forced outages. NYISO (2023) finds that under an severe heat wave, the statewide system margins are deficient in all study years (2024–2032). New York will need adequate energy resources to manage such events as well as resilient transmission infrastructure to withstand severe weather conditions.

PJM

As of 2023, planned transmission projects in PJM included 48 new baseline transmission projects (totaling $6.6 billion), 93 new network transmission upgrades (totaling $180 million) (NERC, 2024a), 1,290 active network transmission upgrades (Monitoring Analytics, 2024), and the planned interconnection of nearly 25 GW of offshore wind capacity targeted to be online between 2031 and 2040 in Maryland, New Jersey, and Virginia (PJM, 2024).

Within PJM, reliability is one of the biggest drivers of transmission need. In early 2023, PJM launched Proposal Window No. 3 for the *2022 Regional Transmission Expansion Plan* to address 2027–2028 baseline reliability violations associated with local constraints from data centers in the Allegheny Power and Dominion Energy Zones, regional constraints from imports into load centers, reliability impacts from the retirement of 11 GW of generation, and the need for reactive power reinforcements (PJM, 2024). In mid-2023, PJM launched Window No. 1 for the *2023 Regional Transmission Expansion Plan*, which analyzed 2028 summer, winter, and light load conditions, and the resulting thermal and voltage violations on the system (PJM, 2024).

Large demand growth from data centers led Dominion to propose 44 supplemental transmission projects through the summer of 2025. To mitigate anticipated constraints and reliability concerns, Dominion will build 500 kV and 230 kV line extensions, reconductor 230 kV lines, and complete substation work (Monitoring Analytics, 2024).

In 2024, PJM and MISO announced a collaboration to study interregional transfer capability between their regions. The study seeks to assess how increasing transfer capability can improve grid resilience, particularly during severe weather events and in response to variable energy generation (FERC, 2025).

SPP

In SPP's *2024 Integrated Transmission Plan*, the region approved its largest transmission portfolio in SPP history. The plan recommends the construction of a new, roughly 440-mile, 345 kV transmission line from Belfield to Maurine to New Underwood to Laramie River, along with other upgrades, to enhance south-to-north transfer capabilities within SPP. The project would expand the footprint of extra-high-voltage transmission in the area, creating greater energy access for rural communities in Western Nebraska, South Dakota, and North Dakota (SPP, 2025b). Additionally, SPP recommends Potter-Crossroads-Phantom 765 kV line along with a new 345 kV line from Beckham County to Potter to enable the transfer of power from the Texas Panhandle to the southeast corner of New Mexico, reinforcing the system in preparation for the extensive load growth anticipated in the region (SPP, 2025b).

SPP's reliability assessment in the *2024 Integrated Transmission Plan* indicates a sevenfold increase in its base reliability needs—both thermal and voltage—compared with the *2023 Integrated Transmission Plan* assessment. SPP identifies two primary regions with voltage concern: southern New Mexico and the area surrounding Lake Sakakawea in North Dakota. These regions have experienced above-average load growth, largely driven by ongoing oil and gas development, straining the existing transmission network (SPP, 2025b). SPP also acknowledges that all forms of power generation face significant challenges during severe weather conditions. The 2024 report emphasizes that these risks will escalate dramatically unless proactive measures are implemented to prepare for and mitigate the impacts of such severe weather events (SPP, 2025b).

Southeast

SERC finds in its *2023–2033 SERC Annual Long-Term Reliability Assessment Report* that new and upgraded transmission facilities will be necessary to enhance reliability and improve transfer capabilities within its region (SERC, 2024a). In its *2024–2026 Regional Risk Report* (SERC, 2024b) SERC recommends enhancing transmission systems and modernizing infrastructure through the integration of advanced technologies and grid monitoring tools to maintain reliability. Entities within the region anticipate adding more than 3,800 miles of transmission lines by 2034 to support load growth and generation interconnections, resolve transmission constraints, and improve grid resilience (SERC, 2024a).

SERTP's *2024 Regional Transmission Plan* includes approximately 350 transmission projects, totaling an estimated $16.7 billion, necessary to ensure reliability and resilience throughout the ten-year planning horizon, including 1,643 circuit-miles of new transmission lines and 2,257 circuit-miles of uprated lines (SERTP, 2024). The projects aim to resolve overloads, offer redundancy, and accommodate load growth.

NERC's *2024 Long-Term Reliability Assessment* reports that entities within SERC-Florida are planning on 668 miles of new transmission lines through 2030 and 256 miles of line upgrades through 2031 (NERC, 2024a). The Florida Power & Light (FPL) transmission plan (FPL, 2025) includes just one proposed future addition of 230 kV and above bulk transmission line for the reporting period from 2025 to 2034: a 79-mile, transmission line rated at 230 kV with a capacity of 1,195 MVA. This project is expected to be in service in June 2026, connecting FPL's Whidden Substation to a new Sweatt Substation (FPL, 2025).

In the Southeast, the *Carolinas Resource Plan*, published by Duke Energy Progress and Duke Energy Carolinas, emphasizes that transmission upgrades will be needed to interconnect new generation and energy storage facilities, ensuring resource adequacy and system reliability as load increases and coal facilities are retired (Duke Energy, 2023b). Duke Energy (2023a) further indicates that transmission investments will be needed to meet expected demand growth and forecasted solar procurement in the medium and long term. In 2021, Duke Energy Carolinas and Duke Energy Progress identified 18 transmission network upgrades—termed *Red Zone Transmission Expansion Plan* (RZEP) projects—to enable the interconnection of generation in the high solar viability "red zone" areas of their transmission systems (Duke Energy, 2023b). Of the 18 RZEP projects, the North Carolina Utilities Commission acknowledged the need for 14 RZEP projects in the 2022 Carbon Plan Order. Transmission upgrade costs for the *Carolinas Resource Plan* Portfolio P3 Base are estimated at almost $1.5 billion for Duke Energy Carolinas and over $1.3 billion for Duke Energy Progress in 2030, and at almost $5.4 billion for Duke Energy Carolinas and $3.4 billion for Duke Energy Progress in 2035 (Duke Energy, 2023b).

TVA's *2025 Draft Integrated Resource Plan* (IRP) explains that the likelihood of significantly upgrading the transmission system increases as the penetration of inverter-based solar and storage increases. The inverter-based resources require more complex transmission upgrades on a per MW basis compared with larger generating units, given the dispersed and relatively small scale of these resources. TVA (2024) further explains that a robust transmission system can improve the reliability of the system and lower consumer costs by allowing for imports and exports of power from and to neighboring utilities during a period of need. Additionally, transmission could allow for a more diverse geographic footprint of available resources and energy storage, which is more resilient to disruptions.

In its 2025 IRP update, Georgia Power identifies 23 strategic transmission projects to improve power transfer across the state. Project need dates range from 2025 through 2033, with roughly half of the projects being 500 kV lines and half being 230 kV lines. Many of the strategic transmission projects—including the ~30-mile Ashley Park–Wansley 500 kV line, ~65-mile McGrau Ford–Middle Fork 500 kV line, ~120-mile Farley–Tazewell 500 kV line, and ~65-mile Hatch–Wadley Primary 500 kV line—improve system reliability, facilitate integration of additional generation (especially new solar), promote sustainability and grid resilience, and improve operational flexibility and reliability on existing facilities (Georgia Power, 2025).

NorthernGrid

Across NorthernGrid, utilities are planning to increase regional and interregional transmission ties. Several transmission investments are being planned for this decade, including new high-voltage transmission capacity.

Puget Sound Energy (PSE) notes that for over a decade, the western energy market has benefited from surplus capacity, enabling PSE to cost-effectively meet demand by purchasing energy from the regional power market through firm transmission capacity (PSE, 2023). However, recent changes in the wholesale electric market have significantly altered supply and demand dynamics in the region, resulting in tighter supplies and increased pricing volatility.

In response, PSE plans to replace short-term market supplies with firm resource adequacy qualifying capacity contracts that comply with the Clean Energy Transformation Act. This approach faces challenges, such as permitting and building new generation and storage resources. Furthermore, it requires the addition of significant transmission infrastructure to meet growing demands. PSE aims to enhance its transmission capacity by up to 8,500 MW by 2033 to facilitate access to intermittent resources. This expansion includes 3,447 MW from East of the Cascades or Central and Eastern Washington, 800 MW from the Rocky Mountain Region or Montana and Wyoming, and 4,247 MW from the Cross Cascades. PSE is also considering the Boardman to Hemingway (B2H) and Gateway West transmission projects to access intermittent resources in Idaho and/or Wyoming.

Idaho Power's 20-year IRP (2023) includes the B2H 500 kV transmission line to connect the Pacific Northwest and Idaho, which was initially anticipated to come online by 2026 but has experienced delays, and three Gateway West transmission phases spread across the 20-year plan to connect the Magic Valley and Treasure Valley. The first phase of Gateway West, comprising the Midpoint–Hemingway #2 500 kV line, Midpoint–Cedar Hill 500 kV line, and Mayfield substation, is expected to come online in late 2028. NorthernGrid's (2023) *Regional Transmission Plan* designates the B2H, Hemingway–Midpoint #2, Midpoint–Cedar Hill, Cedar Hill–Populus, and Populus–Anticline projects as together constituting the most cost-effective strategy to support the NorthernGrid system over the next decade. Additionally, in its 2023 IRP, Idaho Power determined that the Southwest Intertie Project-North (SWIP-N), a 500 kV transmission line between Idaho and Nevada, is advantageous given the diverse seasonal load profile of the Desert Southwest region compared with Idaho Power and the Pacific Northwest region. In the plan, Idaho Power analyzed SWIP-N as providing a 500 MW resource equivalent capacity from the Desert Southwest during the winter months, starting in 2027. SWIP-N was one of the projects selected in the first round of capacity contracts of DOE's Transmission Facilitation Program (40106).

In NorthernGrid West, Avista's 10-year assessment documents several transmission system needs attributable to load growth, particularly south and west of Spokane. To address reliability concerns, the Blue Bird–Garden Springs 230 kV project has been identified as the backbone segment of a broader West Plains Transmission Reinforcement project. Its primary goal is to develop a new, independent 230 kV source west of Spokane by connecting to the BPA Bell–Coulee #5 230 kV transmission line. This upgrade aims to improve contingency performance and increase system stability, as well as enhance power transfer capability between Avista and BPA by 10% to 30%, depending on the season. Avista also identifies reliability concerns in areas in which consistent load growth outpaces transmission system reinforcements, resulting in thermal and voltage violations, especially during heavy winter conditions (Avista, 2024a).

Within the NorthernGrid planning area, an independent transmission company is developing North Plains Connector (NPC), which is a planned 525 kV HVDC line with 3,000 MW capacity to connect the Western Interconnection and Eastern Interconnection between Colstrip, Montana, and North Dakota (DOE, 2025a; *see* call out box below for more about DOE's involvement in this project). Avista, NorthWestern Energy, and PSE have each entered into nonbinding memoranda of understanding with the transmission developer to own a fraction of the transmission line capacity (Avista, 2024b; NorthWestern, 2024; PSE, 2024). In its 2025 IRP, Avista evaluated the benefit of the NPC as a capacity-only resource for resource adequacy and found that the capacity benefits would be beneficial to customers. Through the NPC, Avista would gain access to both MISO and SPP markets, enabling cross-interconnection power transactions with generation resources that experience different weather patterns (Avista, 2024a).

DOE Coordination of Federal Transmission Permitting

Pursuant to its authority under section 216(h) of the FPA, DOE is leading the environmental review and permitting of the NorthernGrid NPC project. DOE is leading the coordination of federal environmental reviews for the Bureau of Land Management, U.S. Forest Service, and Agricultural Research Service. DOE is also collaborating with the Montana Department of Environmental Quality to jointly prepare the Environmental Impact Statement for NPC to ensure that it meets both federal and state requirements for environmental review.

Department of Energy, North Plains Connector, at https://www.energy.gov/nepa/doeeis-0568-north-plains-connector-multiple-locations.

Pursuant to the same FPA authority and informed by the lessons learned from the NPC pilot, DOE has established the Coordinated Interagency Transmission Authorization and Permits Program, a collaborative process between federal agencies and project proponents to ensure the timely review and decision-making for federal authorizations consistent with the nation's environmental laws, including laws that protect endangered and threatened species, critical habitats, and historic properties.

Department of Energy, Coordinated Interagency Transmission Authorization and Permits Program, at https://www.energy.gov/gdo/coordinated-interagency-transmission-authorizations-and-permits-program.

Resource adequacy is a primary concern for the NorthWestern balancing area to ensure reliable and cost-effective energy service. Presently, NorthWestern relies heavily on imported energy and lacks sufficient supply of resources to meet peak loads throughout the year. NorthWestern aims to reduce reliance on volatile energy market purchases and mitigate transmission congestion risks that limit energy imports into the region. Significant transmission upgrades will be necessary to increase transfer capabilities on interregional paths to reliably meet the projected demand growth in the region (NorthWestern, 2023).

BPA's 2024 Transmission Plan proposes new upgrades and investments in high-load growth areas, such as Portland and Eugene in Oregon and the Northern Mid-Columbia and Tri-Cities areas in Washington State. Additionally, the plan recommends seven transmission upgrade and reconductoring projects to uphold system reliability in multiple regions served by BPA, including Spokane, Seattle, Central Oregon, and Eugene areas. According to BPA (2024), severe transmission constraints were observed on the California-Oregon intertie that were due to prolonged outages at the Buckley 500 kV substation in 2023. To ensure reliability along this critical corridor that connects Oregon and California, BPA recommends essential substation upgrades.

PGE's IRP proposes several regional upgrades to increase transmission capacity on existing flowgates and new transmission options to access over 500 MW of high-quality wind and solar resources in Wyoming and Nevada by 2030 (PGE, 2023).

PacifiCorp's 2025 IRP identifies several significant upgrades needed to comply with state-specific environmental regulations while accommodating projected regional load growth. These include projects to increase transmission capacity from Southern Utah to the Wasatch Front area. PacifiCorp's plan for the Medford, Oregon, area includes the construction of a 230 kV transmission line between the Lone Pine and Whetstone substations and a new 500/230 kV substation named Sams Valley (PacifiCorp, 2024).

Within NV Energy's service territory, Greenlink West and Greenlink North are two transmission projects in development that will address limited transfer capacity in the near term (NV Energy, 2024). Areas of the West are anticipating resource shortfalls. WECC (2024) estimates that entities in the Western Interconnection plan to add over 172 GW of new generation capacity over the next decade, more than double the capacity added in the last decade. Given the substantial load growth and resource additions, WECC's resource adequacy analysis indicates that without adequate interregional transfer capabilities, the NW–Northwest and NW–northeastern regions (aligning roughly with the Needs Study regions of NorthernGrid West and NorthernGrid East) could be severely affected, experiencing more than 1,900 hours of demand at risk annually (WECC, 2024).

WestConnect

Across WestConnect, utilities are anticipating the need for additional transmission capacity and are planning investments that will maintain system reliability and support future load growth. Although WestConnect as an Order 1000 region has not identified any regional transmission needs (WestConnect, 2025), individual utilities within WestConnect are making substantive upgrades in their respective service areas. Some of the transmission investments in the WestConnect footprint are described below.

Xcel Energy (2024) identifies the need for three key network upgrades to deliver intermittent generation from Southern and Eastern Colorado to the majority of the utility's customers in the Denver Metro area. Xcel Energy is also exploring the necessity of an additional 230 kV transmission path to accommodate the rapidly increasing load in the area (Xcel Energy, 2024).

Salt River Project's analysis indicates that up to 380 miles of new or upgraded 500 kV and 230 kV transmission lines and 12 new 500/230 kV transformers may be needed over the next decade, necessitating proactive planning because of long lead times associated with infrastructure development (SRP, 2023).

Arizona Public Service's *Ten Year Transmission System Plan* (APS, 2024) identifies five critical transmission projects to support growing demand, reliability, and new generator interconnections. The projects include new or rebuilt transmission lines and associated facilities with an estimated $5.7 billion investment through 2033 (APS, 2024).

PNM (2023) highlights that its ability to reliably meet demands in the northern load area is contingent on both the transmission system and the generation resources within the load pocket. The existing bulk transmission system lacks the capacity to meet peak demands without the support of local resources, such as Reeves Generating Station, Rio Bravo, and the Valencia Power Purchase Agreement. These resources are vital for ensuring reliability during peak demand periods and in the event of transmission outages. However, the Valencia Power Purchase Agreement is set to expire in 2028 and Reeves is scheduled for retirement by 2030. In its 2023 IRP, PNM proposes seven new transmission projects, incorporating over 500 miles of new transmission lines and upgrades (PNM, 2023). PNM must evaluate potential alternatives to maintain reliability, which may involve investing in new load-side resources, new transmission infrastructure, or a combination of the two. El Paso Electric's latest System Expansion Plan, which responds to forecasted reliability criteria violations, recommends 18 projects for upgrade or new construction between 2025 and 2034 to enhance system reliability and improve El Paso Import Capability (EPE, 2024).

Alaska and Hawaii

AEA is developing needed upgrades to the Railbelt system to address aging infrastructure, lack of redundancy, and limited transfer capacity. Several utilities are planning facility upgrades along the system (AEA, 2025—*see* slide 19). One of these upgrades is AEA's Railbelt Innovation Resiliency project, which includes storage, an HVDC submarine cable, and new transmission lines running parallel to existing lines along the Railbelt.

In the long term, Oahu, Hawaii Island, and Maui will need additional transmission infrastructure to interconnect new generation and support future load growth (Hawaiian Electric, 2024a). The transmission system on Maui may require transmission network upgrades in the near term, while transmission expansion on Oahu and Hawaii Island may come further in the future, depending on the point of interconnection of new generating resources growth (Hawaiian Electric, 2024a). In addition to reliability and load growth, investments in transmission in Hawaii are also needed to improve the resilience of the system against natural disasters including hurricanes and wildfires. In 2024, Hawaii Public Utility Commission approved Hawaiian Electric's five-year, $190 million plan to improve grid resilience with transmission and distribution upgrades on critical circuits (Hawaiian Electric, 2024b).

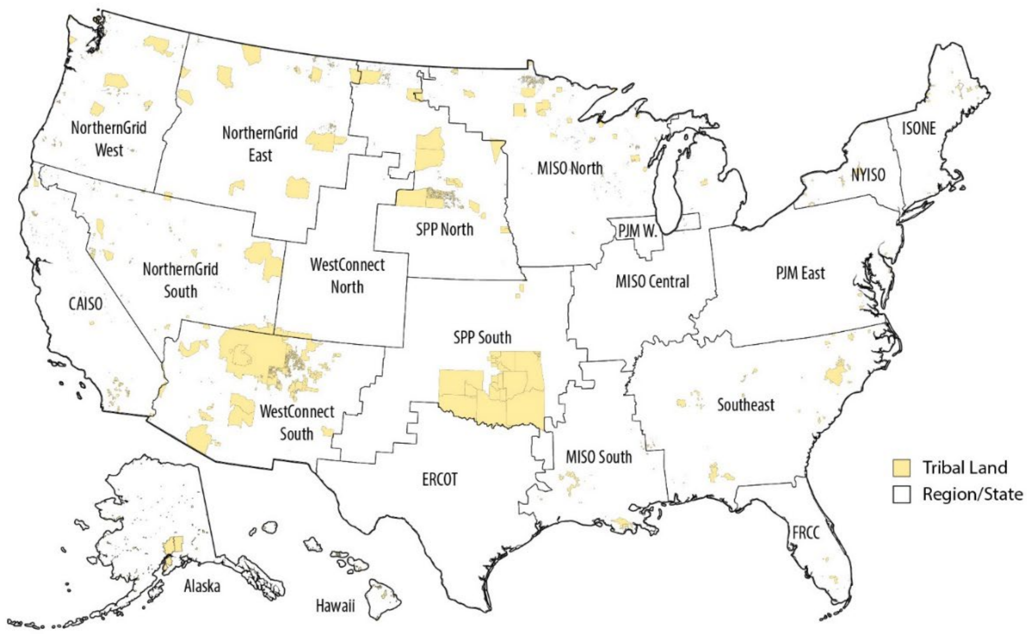
Tribal Transmission Needs

Individual Tribal Nations express a wide array of energy needs and goals, ranging from access to basic electricity service and increased power reliability and energy efficiency tools, to the development of utility-scale generating plants. Access to transmission is a key part of this multifaceted Tribal energy landscape. The U.S. has 575 federally recognized Tribes[44] across 34 states; Tribal proximity and access to transmission infrastructure varies widely across the

[44] The list of federally recognized tribes as of January 30, 2026 can be found at https://www.federalregister.gov/documents/2026/01/30/2026-01899/indian-entities-recognized-by-and-eligible-to-receive-services-from-the-united-states-bureau-of.

country, which presents challenges to achieving the range of goals that include improving electricity access, reducing electricity outages, reducing household energy burdens, and enabling utility-scale generation to address growing electricity demand nationwide (NLR, 2026b).

Tribal lands are spread across the transmission planning regions considered in this study (Figure VI-1). About 2.3% of the nation's transmission miles are on Tribal lands (OIE, 2023). NLR (2026b) reports that over 1,000 substations at voltages above 100 kV are currently located on or near Tribal lands (Table VI-1), with the highest numbers in SPP South and the Southeast. However, circumstances vary widely when considering the nation's miles of transmission and substations on or near Tribal lands. Much of that transmission is for local network delivery (138 kV), which can limit opportunities for utility-scale development without significant transmission upgrades. There are some high-capacity 500 kV lines, but in many cases, Tribes have limited access to them even when they run across the reservation.



Source: National Laboratory of the Rockies (2026b).

Note: Tribal land in the map primarily refers to reservations but also includes spaces like Oklahoma Tribal Statistical Areas and Alaska Native Villages. This map includes both federally and state-recognized Tribes, as well as concentrations of Tribal members outside of reservation areas.

Figure VI-1. Needs Study regions with Tribal lands identified.

DOE Work on Mapping Energy Resources

The Department funded the development of the Geospatial Energy Mapper (GEM) tool at Argonne National Laboratory. GEM provides mapping data and analysis tools for planning energy infrastructure in a geographic context. GEM is an interactive web-based decision support system that allows users to locate areas with high suitability for power generation and potential energy transmission corridors in the U.S.

Argonne National Laboratory, Geospatial Energy Mapper, at https://gem.anl.gov/.

Table VI-1. Substations greater than 100 kV within or near tribal lands.

Region	Total High-Voltage Substations	Substations on/Near Tribal Lands
RTOs		
CAISO	2,137	1 (<1%)
ERCOT	3,703	1 (<1%)
ISO-NE	1,960	1 (<1%)
MISO Central	3,911	0 (<1%)
MISO North	2,286	11 (<1%)
MISO South	2,319	25 (1.1%)
NYISO	1,696	10 (<1%)
PJM East	5,925	5 (<1%)
PJM West	1,140	0 (<1%)
SPP North	1,027	34 (3.3%)
SPP South	3,002	919 (30.6%)[a]
Non-RTO Regions		
NorthernGrid East	791	43 (5.4%)
NorthernGrid South	878	13 (1.5%)
NorthernGrid West	2,935	75 (2.6%)
WestConnect North	998	10 (1%)
WestConnect South	946	48 (5.1%)
Southeast	8,500	137 (1.6%)
FRCC	1,767	0 (<1%)

[a] Includes Tribal Statistical Areas of Oklahoma.

Source: The National Transmission Planning Study, Chapter 3, power flow plannings cases for 2030–2031 (DOE, 2024c) with additional geospatial analysis by the authors (NLR, 2026b); comparable data for Alaska and Hawaii not available.

Some of the Tribes with the largest land area have little transmission, and some such as Navajo Nation and Hopi Tribe have many homes with no access to electricity. Elsewhere, low incomes and higher electricity rates generally add to a Tribal household's energy burden. The Office of Indian Energy (OIE) found in 2023 that energy costs as a share of annual income were 28.3% higher for households on Indian land than they were for the rest of the country (OIE, 2023). This is especially true where the area is served by lower-voltage transmission lines that have higher electricity losses per mile.

Lack of transmission infrastructure is one of the most significant barriers to energy development on Indian lands, as transmission costs significantly increase the costs of Tribal energy development, especially because many Tribal lands are located far from existing infrastructure (DOE, 2023b).

Investments in transmission infrastructure on or near Tribal lands will help address unmet needs for Tribal communities for continued energy development, reliability, security, and resilience (DOE, 2023b). However, planning, siting, permitting, and building transmission on Tribal lands can be a challenging process that spans multiple jurisdictions and types of land ownership and requires building trust between Tribal governments and transmission planners, owners, and operators. A significant lack of information and data is a major challenge in quantifying energy-related needs in Tribal communities, as data on energy infrastructure and needs of Tribal communities are often incomplete, inaccurate, outdated, or not documented (DOE, 2023b). Consequently, more analysis and support specifically focused on energy needs and goals on Tribal lands can help better understand opportunities for transmission development (or expanding access where the transmission infrastructure already passes through Tribal lands without delivering power).

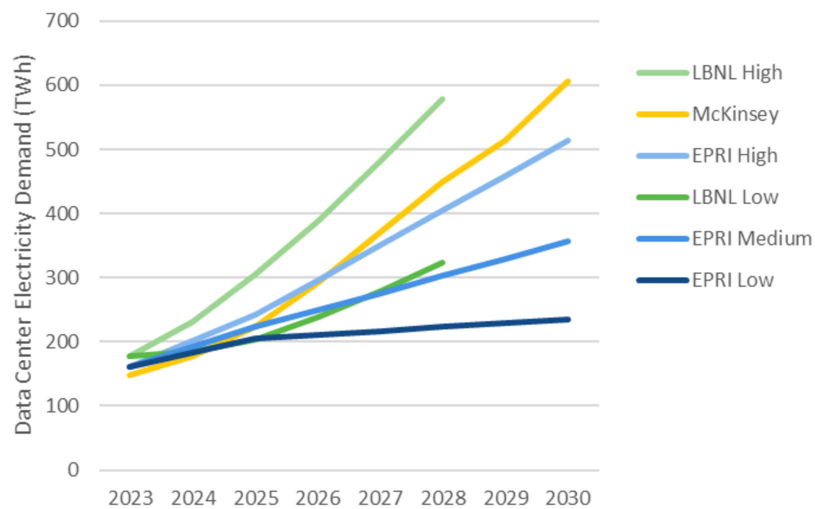
VI.e. Drivers of Future Transmission Needs

As seen in the regional plans discussed above, rapid load growth is a core driver of future transmission needs. At the same time, the evolving energy landscape, marked by a changing resource mix, aging infrastructure, and severe weather events is changing the demands on the transmission system and driving transmission needs across all regions of the nation.

Growth in data centers, artificial intelligence (AI), and cryptocurrency mining; expanding domestic manufacturing, including of batteries and fuel cells; the addition of other large commercial and industrial loads (including smelters, manufacturing centers, hydrogen electrolyzers, and future electrified mass transit or shipping charging stations); and the electrification of industrial, residential, and transportation sectors all contribute to high anticipated future load growth (FERC, 2025; ICF International, 2024; NERC, 2024a). Recently, the load growth from data centers has become a particular focus in the industry that is driving upward trends in demand (*see* call out box below). Using Forecasts provided by regional grid operators and load-serving entities, NERC projects that total U.S. electricity consumption will increase by 25% from 4,281 TWh in 2024 to 5,353 TWh in 2034 (NERC, 2024a). The Energy Information Administration (EIA)'s 2025 Annual Energy Outlook projects a 16% increase in demand by 2034 and a 31% increase by 2040 (EIA, 2025a), while the Electric Power Research Institute (EPRI) projects a 30% to 46% increase in electricity demand between 2020 and 2035, depending on how fast data center load increases (EPRI, 2024). Some regions are anticipating particularly rapid demand growth; NERC (2024a) projects Texas RE's internal demand to grow from almost 89 GW in 2025 to more than 105 GW in 2028. Texas is also projected to see the greatest percentage increase in total electricity consumption over the next ten years (NERC, 2024a).

Data Center Projections

Many utilities, as well as financial and industry analytics firms, cite data centers, specifically AI data centers, as the main driver of electricity demand growth (LBNL, 2024). Figure VI-2 displays several projections of data center growth in the U.S. through 2030, developed by LBNL, EPRI, and McKinsey. These projections show data center load growth of up to over 400 TWh by 2030, which is equivalent to over 10% of total electricity end-use in 2023 (EIA, 2025b).



Source: Lawrence Berkeley National Laboratory (2024), Electric Power Research Institute (2024), and McKinsey & Company (2024).

Note: This graph was developed by DOE using data from the sources of information listed above.

Figure VI-2. Projected data center electricity demand in the U.S.

LBNL (2024) model the future growth of data center electricity consumption across scenarios of varied equipment shipments, operational practices, and cooling energy use, and estimate a compound annual growth rate between 13% to 27% from 2023 to 2028. By 2028, data center annual electricity use could represent between 6.7% and 12.0% of total forecasted national electricity consumption.

EPRI estimates data center electricity consumption in each state. Virginia and Texas have the greatest estimated current data center electricity demand and are also projected to see some of the greatest data center demand increases through 2030, along with states including Arizona and Oregon (EPRI, 2024).

Other sources project data center demand growth in terms of peak capacity. Because of uncertainty around supply-chain constraints, electric generation capacity availability in certain regions, data center flexibility, and efficiency gains in computation and data center operations, FERC (2025) indicates that projected demand growth from data centers will range from 13 to 55 GW by 2030.

The retirement of conventional generation, rapid deployment of new intermittent resources, and shifting load patterns are straining existing infrastructure across many regions. Regions are working to secure enough generation as well as sufficient transmission, to deliver generation to load. In the face of a changing resource mix, transmission lines can offer several reliability benefits, including enhanced stability and improved ancillary services (FERC, 2020). Transmission links can also manage variable generation by balancing supply and demand across markets (NREL, 2024c). Additionally, state policies, utility goals, and market incentives continue to drive significant interest and investment in clean energy resources. However, transmission limitations are a critical bottleneck to interconnecting these new generation sources. As of 2024, over 1,480 GW of solar and wind, as well as 1,030 GW of storage, were seeking interconnection across the country (DOE, 2024d).

At the same time, much of the existing transmission infrastructure is aging and needs replacement. Most transmission infrastructure was constructed in the 1960s and 1970s and is now reaching the end of its useful life (The Brattle Group and Grid Strategies, 2021). Brattle estimates that approximately 4,000 circuit-miles of transmission will need to be replaced each year for the next few decades, at a cost of approximately $10 billion per year, or about a third of recent annual transmission investments (The Brattle Group, 2021). FERC's *2024 State of the Markets* report confirms that aging infrastructure has already become a major driver of recent transmission investments, particularly in ISO-NE and PJM (FERC, 2025).

Severe weather events are driving additional transmission needs for grid hardening and resilience. Across the nation, severe weather events are becoming increasingly frequent and severe (NREL, 2024c). In 2024, the Atlantic Coast experienced an unusually active hurricane season, resulting in widespread power outages. In Texas, Hurricane Beryl, a Category 1 storm, led to over 2.7 million electricity outages in Texas at its peak on July 8 (FERC, 2025). Heat waves, cold snaps, wildfires, and severe storms can simultaneously increase electricity demand and disrupt generation and transmission infrastructure, pushing power systems to their limits.

VII. Future Transmission Needs Assessment through Review of National Modeling Studies

Long-term future transmission needs are evaluated through national-scale research and energy system studies that often fall outside the paradigm of industry-led transmission planning. These long-term studies provide insights into the trends and magnitude of future transmission needs as well as highlight the potential benefits that infrastructure would provide in terms of costs and reliability. Recent long-term transmission studies conducted outside of regional planning processes include analyses guided by capacity expansion modeling[45] and analyses of interregional transfer capacity to support reliability and resource adequacy needs.[46] The collection of studies indicates the need for significant transmission investments over the next 20 years to support increasing electrical demand and new generation while maintaining high reliability and low costs.

- Results from the capacity expansion studies show a strong correlation between future electricity demand growth and needed transmission capacity, indicating that planning for and investing in transmission infrastructure is vital to support load growth of the nation's industry and population.

- DOE's *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid* report (2025b), in accordance with Executive Order 14262, *Strengthening the Reliability and Security of the United States Electric Grid*, identified resource adequacy as a growing concern for the electric grid. Transmission supports resource adequacy by ensuring that power generated by these resources can be delivered to load when needed by enabling the sharing of energy resources across regions with different load profiles, weather patterns, and generation mixes. This connectivity allows systems to better manage peak demand, reduce reliance on local reserves, and respond more effectively to natural disasters. Transmission's role in improving deliverability and resource sharing for resource adequacy can be particularly pronounced for large power systems like the U.S. electricity grid. Resource sharing between regions can offer large potential benefits given the longer distances involved. Long-term studies from NERC (2024d) and National Laboratory of the Rockies (NLR) (NLR, 2026a) found that interregional transmission expansion supports improved resource adequacy across multiple regions and mitigates the impacts of natural disasters, if coordination between regions can be achieved.

The collection of nationwide studies suggests that the need is substantial for investment in transmission, including interregional connections through 2050. The projected scale and location of long-term transmission needs are highly correlated with the driving factors of the

[45] *See* DOE's *National Transmission Planning Study* (DOE, 2024b) and NREL's *2024 Standard Scenarios Report* (NREL, 2024b).

[46] *See* NERC's *Interregional Transfer Capability Study* (NERC, 2024d) and NLR's *Impacts of Regional Coordination on Transmission Needs for Power System Resource Adequacy* (NLR, 2026a).

energy industry, including regional demand projections, the cost to build and operate new generation units, and plant retirement schedules, as well as regulatory and tax structures. Long-term projections for many of these factors are rapidly evolving in 2026, such as expected load growth driven by large loads and data centers. Consequently, the nationwide modeling studies published at the time of writing this report may not accurately reflect the current landscape of future energy markets.

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