U.S. DEPARTMENT OF ENERGY

National Transmission Needs Study

October 2023

United States Department of Energy

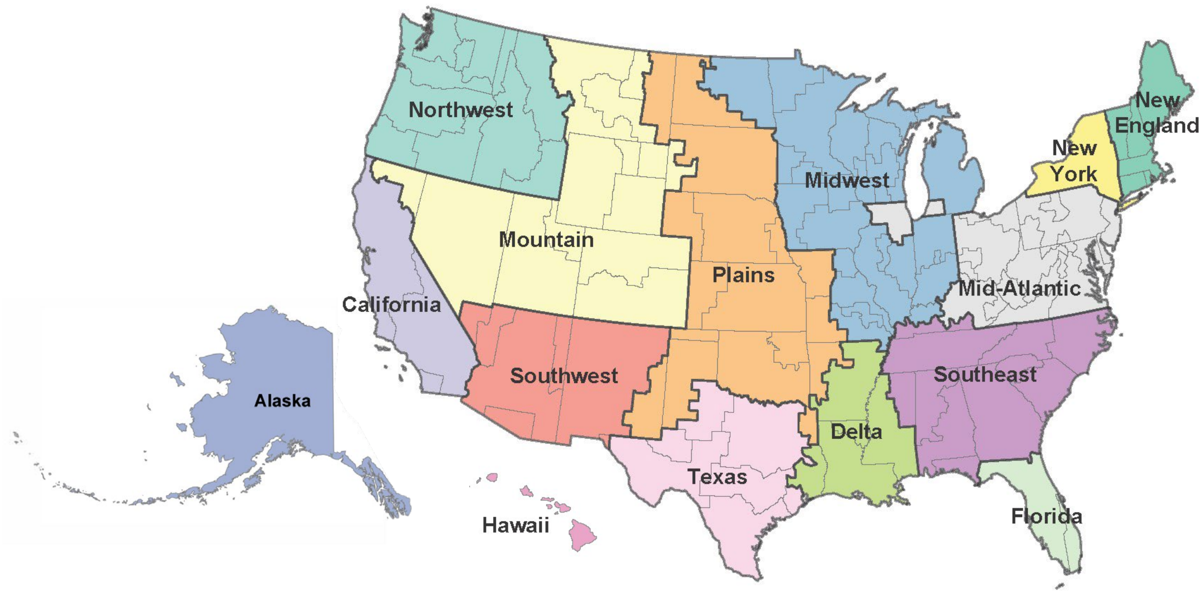
Washington, DC 20585

Executive Summary

A robust transmission system is critical to the Nation's economic, energy, and national security. The electric grid continues to face challenges that are due to aging infrastructure and insufficient transmission capacity. The U.S. Department of Energy undertakes this National Transmission Needs Study (Needs Study) pursuant to Section 216(a)(1) of the Federal Power Act (FPA)[1] to identify transmission needs that are currently harming consumers or expected to do so in the future and that could be alleviated by transmission solutions. Findings from this Needs Study will inform the Department of Energy as it coordinates the use of its authorities and funding that relate to electric transmission, including implementing the many grid resilience and technology investment provisions of the Infrastructure Investment and Jobs Act and the Inflation Reduction Act. The Needs Study is an assessment of publicly available data and more than 120 recently published reports that consider current and anticipated future needs given a range of electricity demand, public policy, and market conditions. All findings of needs are presented by geographic area (*see* Figure ES-1) where appropriate.

The purpose of this study is not to prescribe particular solutions to issues faced by the Nation's power sector. Rather, it assesses need in order for industry and the public to suggest the best possible solutions for addressing them in a timely manner. As used in this study, an electric transmission need refers to the existence of present or expected electric transmission capacity constraints or congestion in a geographic area, consistent with FPA Section 216(a)(1). Geographic areas where a transmission need exists would benefit from an upgraded, uprated, or new transmission facility—including alternative transmission 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).



Source: National Renewable Energy Laboratory.

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

Historical Transmission Investments Declined in the Second Half of the Last Decade, and Were Focused Primarily on Incremental Reliability Needs

A review of historical transmission system data from 2011 to 2020 provides insight into key indicators that demonstrate the need for increased transmission capacity. Annual average spending on transmission was between $0.17 (Florida) and $5.90 (New England) per megawatt-hour (MWh) of annual load in each region between 2011 and 2020. These investments resulted in annual average builds between 5 (Alaska) and 800 circuit-miles (Texas) of new or upgraded transmission. Many of these investments were made in the first half of the decade, with transmission investments steadily declining since 2015 in several regions. Addressing incremental reliability needs remained the main driver of all transmission investments.[2] Figure ES-2 shows the circuit-miles of all new or upgraded transmission energized in each region between 2011 and 2020 by motivating driver. In all, 3,300 circuit-miles of new or upgraded transmission were energized annually, on average, within all regions of the United States. Only 70 circuit-miles of interregional transmission were energized between the regions on average each year.

[2] As discussed in Section IV.a, the historical transmission system dataset used in this review defines a transmission project motivated by a "reliability" need driver as one that meets a need to improve reliability concerns of the local or regional electric grid, as defined by the relevant state, regional reliability entity, or the North American Electric Reliability Cooperation standards.

Source: Data from MAPSearch Transmission Database (2023).

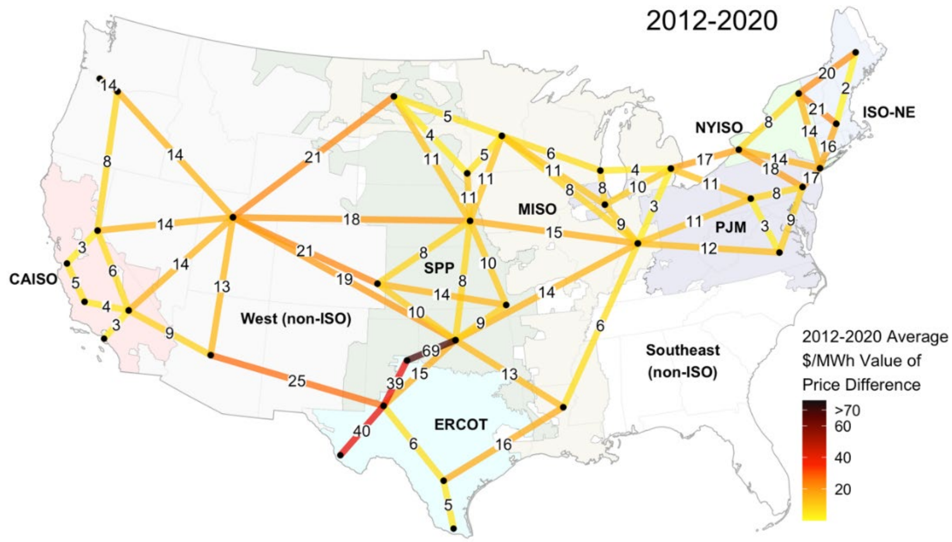
Note: The scale of circuit-miles shown on the y-axis changes with each row of charts, as indicated by the circle, obscuring the scale of projects relative to other regions. All interregional projects are grouped together and shown separately from regional projects.

Figure ES-2. Regional circuit-miles of new or upgraded transmission lines (≥100 kV) energized in each year by project driver.

Persistently High Wholesale Market Price Differences Between and Within Regions Show That Several Regions Are Experiencing Transmission Congestion and Constraints Today

Wholesale market price differentials between and within the regional transmission organizations (RTOs) and independent system operators (ISOs) (together, RTOs/ISOs) also provide insight into where transmission congestion currently exists. Several regions of the country—notably portions of the Plains, Midwest, Mid-Atlantic, New York, and California—have experienced persistently high wholesale electricity prices over the past 3–5 years. Extreme conditions and high-value periods play an outsized role in the value of transmission, with 50% of transmission congestion value coming from only 5% of hours. The price differentials between two locations on the power grid shows where transmission constraints are preventing lower-priced energy from reaching these high-priced areas and quantifies the congestion relief value of building transmission between the locations. Figure ES-3 shows the average difference in hourly prices between several locations on the grid. The highest congestion relief value is found across the Eastern, Western, and Texas Interconnections and between New England and New York. But congestion relief would provide significant value within and between other regions as well.

As shown in Figure ES-3 below, there are gaps outside of RTO/ISO regions where information regarding the economic value of congestion is not available; these gaps do not reflect the absence of transmission needs but rather the absence of market data with which to calculate price differentials. Transmission system operators in non-RTO/ISO regions do not use a market-based approach to determine the economic value of transmission congestion. Instead, they often use the availability of transmission service and the need to deny user requests for transmission service as a measure of congestion. In Southeastern regions not served by RTOs/ISOs, transmission system operators use Transmission Loading Relief administrative procedures to curtail or reduce agreed-upon transmission services. The incidence of those curtailments provides one measure of congestion. But such measures of congestion do not provide information on the value of foregone transmission service, nor do they provide insight into where *future* congestion might arise.



Source: Lawrence Berkeley National Laboratory (Millstein et al. 2022b).

Figure ES-3. Average hourly difference in price between selected hub zones within and across regions between 2012 and 2020.

Assessment of Published Studies Reveals Current and Future Drivers of Transmission Needs—and the Benefits to Consumers of Addressing Those Needs—in Every Region

As part of this Needs Study, DOE undertook a review of recently published power systems studies from a broad cross-section of subject matter experts and industry sectors. This review captures the historic and anticipated drivers, benefits, and challenges of expanding the Nation's electric transmission system as assessed by a variety of entities, including the U.S. Government, national laboratories, academic institutions, consultants, and a range of industry participants. In examining findings of transmission need from existing studies, the Department can identify common drivers of transmission need, as well as capture unique geographic differences that drive the need for transmission across the United States. In addition, this approach allows the Department to consider transmission needs anticipated to arise under a range of future electricity demand, public policy, and market conditions.

Across the literature, the main determinants of need for transmission expansion identified include grid reliability and resilience, congestion relief, new generation resource interconnection, and load growth accommodation. Overall, findings assessed in this Needs Study demonstrate transmission capacity expansion can serve to enhance system stability through improved operational flexibility, resource sharing, and frequency response. Reliability and resilience needs are expected to require additional transmission as economic factors and clean energy targets prompt higher levels of variable energy resource integration and as extreme weather events nationwide continue to increase in frequency and intensity. Study findings also indicate that interregional and cross-interconnection transmission investments will improve system resilience and alleviate resource adequacy concerns by enabling increased access to diverse generation resources across different climatic zones. Throughout the country over the next decade and beyond, increasing consumer demands, electric utility decarbonization targets, and federal and state policy are expected to drive changes in electricity supply and change the way electricity is used, including by increasing electrification of end-use technologies. These changes will put additional burden on the existing transmission system and create significant need for additional transmission investment. In addition, study findings indicate that additional transmission deployment in nearly all regions, along with other alternative transmission solutions, can help alleviate transmission system congestion. Equitable investments made with a lens of energy justice in areas with higher cumulative burden may mitigate existing harms and increase benefits to frontline communities facing high energy burden, longer-duration outages, and higher levels of environmental hazards.

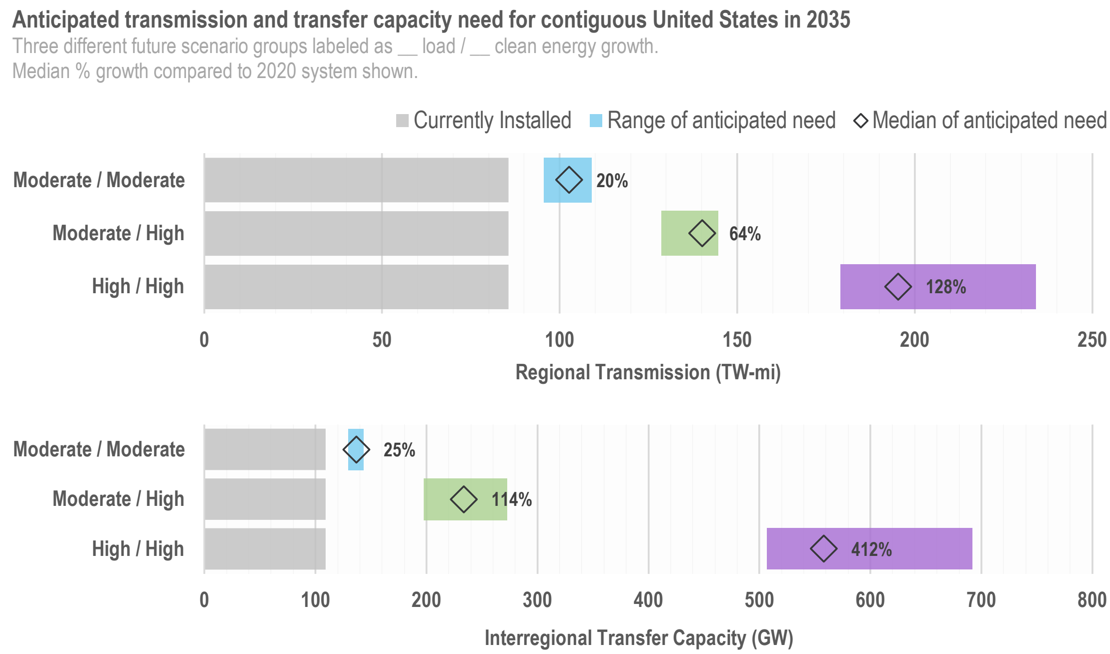
The studies assessed here also highlight that transmission deployment faces siting and permitting challenges. Alternative transmission solutions (e.g., energy storage, grid-enhancing technologies, and advanced conductors and cables) and the strategic siting of generation and transmission may help avoid these challenges in some, but not all, cases. These techniques are particularly useful to defer new transmission investments by several years or in cases when the carrying capacity of existing transmission must be increased. But such solutions will almost certainly fail to meet the full scope of transmission needs identified by this Needs Study.

Capacity Expansion Studies Demonstrate That Significant Future Transmission Investments are Necessary to Address Anticipated Needs Under a Wide Variety of Future Scenarios

In the Infrastructure Investment and Jobs Act of 2021, Congress expanded the scope of this Needs Study by requiring DOE to assess not just existing transmission needs, but also expected future transmission needs. Anticipated future transmission need can only be estimated using assumptions about the power sector of the future. Several national laboratory and academic researchers have performed nationwide capacity expansion studies to co-optimize generation and transmission growth given different future scenarios. The transmission builds resulting from six recently published capacity expansion studies were considered to identify future regional transmission and interregional transfer capacity needs. Because future transmission need can only be estimated and are uncertain, ranges of anticipated need from the study results are presented.

Analysis of these capacity expansion models across a range of potential system futures shows significant future need for transmission both within regions and between them (i.e., interregional transmission). With respect to regional needs, Figure ES-4 (top) shows the range of within-region transmission deployment needed for the contiguous United States for three different scenario groups in 2035. Capacity expansion studies show within-region transmission deployment needs to increase by 20% (median result) to meet a future with moderate load and clean energy growth in 2035. This within-region transmission need increases to 64% (median result) to meet a future with high clean energy growth in 2035, which most closely represents the anticipated future power sector given all existing state and federal legislation. This need rises again to 128%—a more than doubling of the current system—to meet a future with high load growth in 2035.

With respect to interregional transmission need, Figure ES-4 (bottom) shows the range of interregional transfer capacity need for the contiguous United States for three different scenario groups in 2035. Like regional transmission deployment, interregional transfer capacity must grow as generation and load changes in the future. Median capacity expansion results show interregional transfer capacity must grow by 25% to meet future moderate load and clean energy growth, by 114% to meet moderate load and high clean energy growth, and by 412% to meet high load growth futures by 2035. The latter two needs represent a doubling and quintupling of the nation's current interregional transfer capacity, respectively.



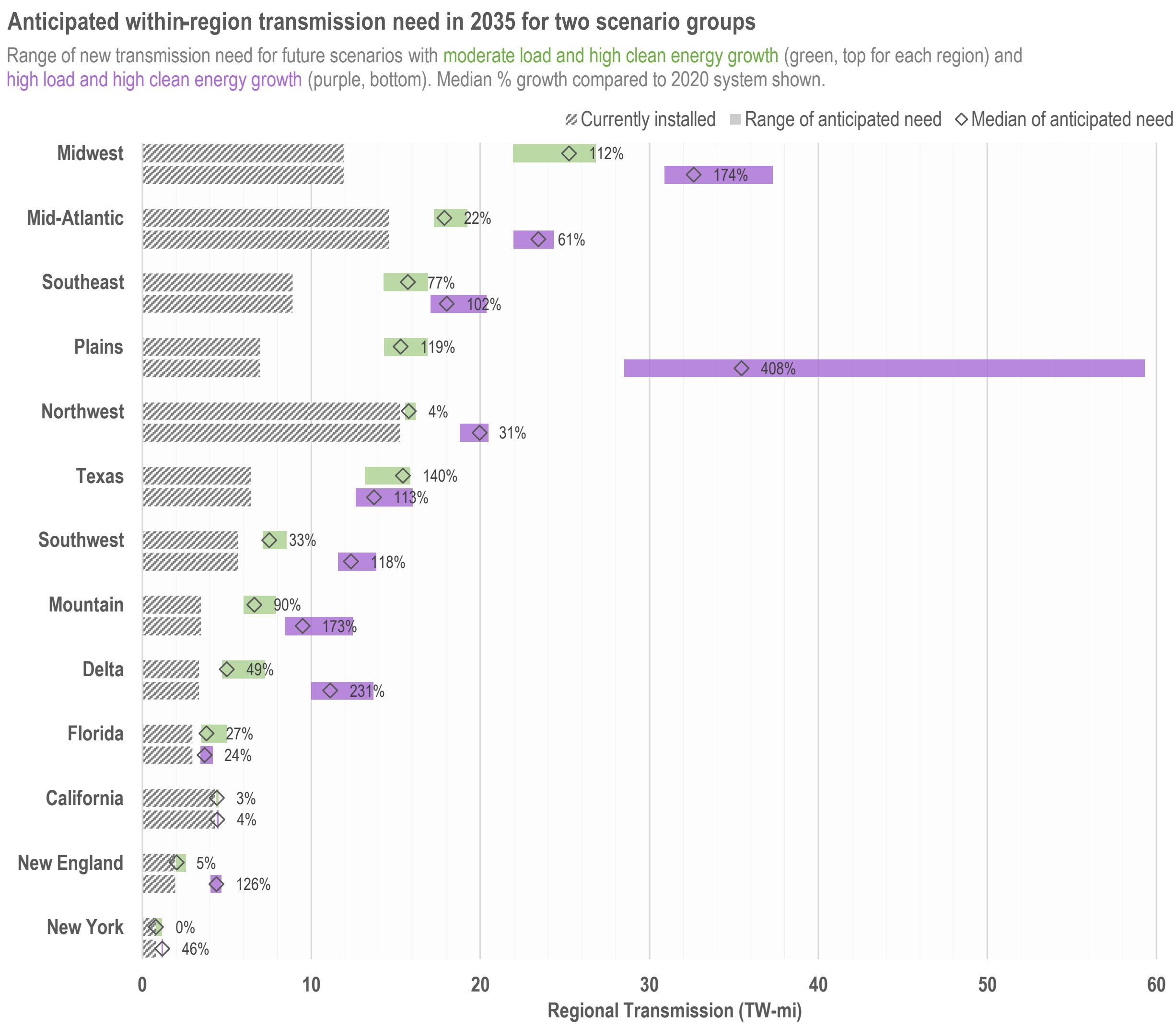
Note: Median and interquartile range of within-region transmission and interregional transfer results for six different recent capacity expansion models shown. Currently installed transmission and transfer capacity as pictured from Denholm et al. (2022a). Considered scenarios are categorized into groups by their future load and clean energy growth, respectively (e.g., ***High*** *load/****High*** *clean energy growth).*

Figure ES-4. Anticipated future regional transmission and interregional transfer capacity need in 2035 for the contiguous United States across three scenario groups.

The capacity expansion modeling results can be further analyzed to describe specific within-region and interregional transmission needs, as shown in Figure ES-5 and Figure ES-6. The largest relative growth of regional transmission deployment (*see* Figure ES-5) compared with the 2020 system will be needed in the Texas (140% median increase), Plains (119%), Midwest (112%), Mountain (90%), and Southeast (77%) regions by 2035 to meet moderate load and high clean energy growth future scenarios. These 2035 deployment needs increase even more under high load growth scenarios (*see* Figure ES-5, purple scenario group) for nearly all regions, but especially for the Plains (408% median increase), Delta (231%), Midwest (174%), and Mountain (173%) regions.

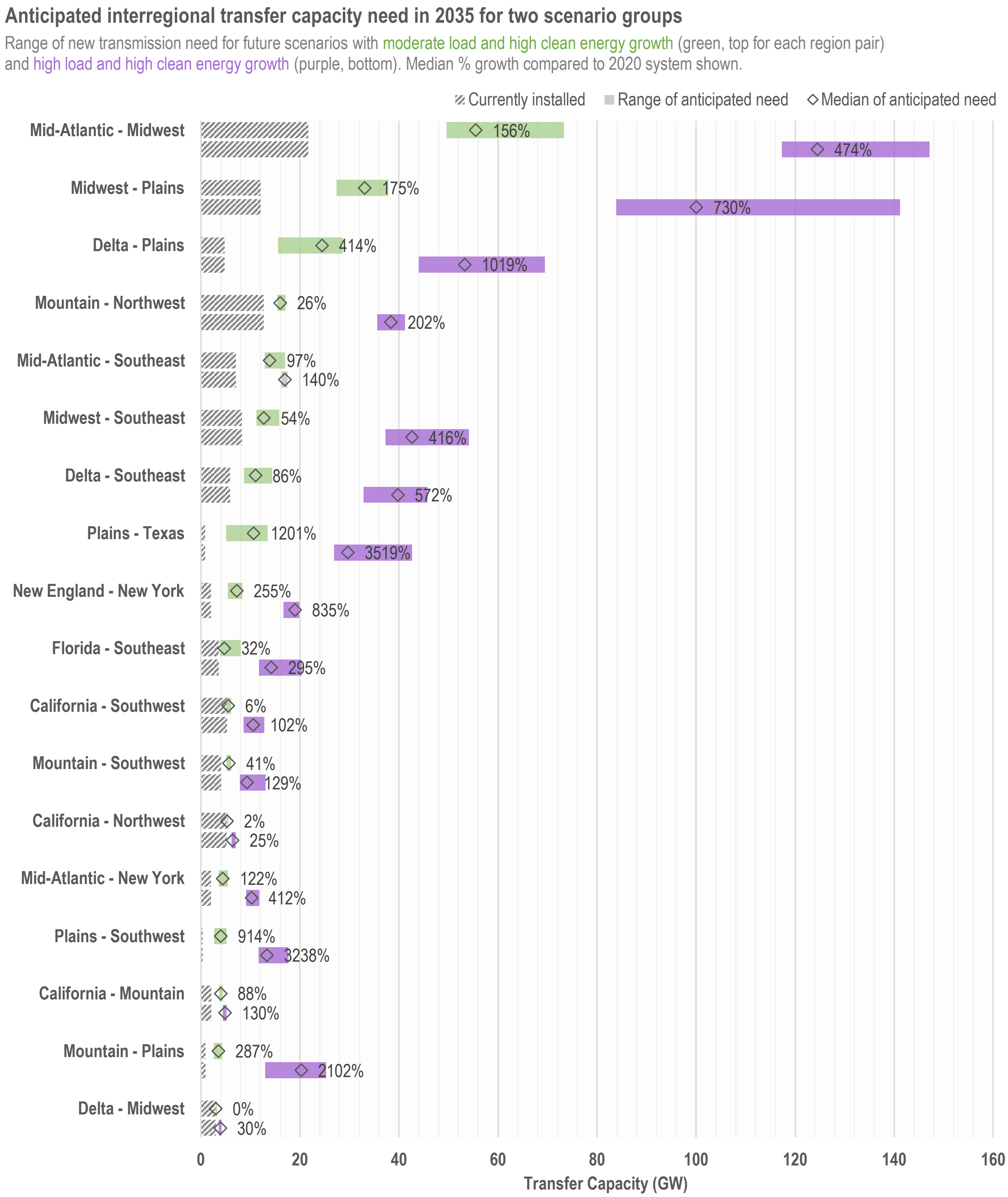
Large relative growth in interregional transfer capacity (*see* Figure ES-6) compared with the 2020 system will be needed between the Delta and Plains (414% median increase), New England and New York (255%), Midwest and Plains (175%), and between the Mid-Atlantic and Midwest (156%) regions by 2035 to meet moderate load and high clean energy growth future scenarios. Large interregional transfer capacity need is also found between the three interconnections to help provide electricity given the evolution of supply and demand nationwide and to maintain reliability given an increase in extreme events that stress the grid.

Like the within-region transmission deployment need, high load scenarios further increase the interregional transfer capacity need for all regional pairs. These changes in interregional transfer capacity need are significant, with anticipated 2035 need ranging from 25% (median California – Northwest transfer) to 3519% (median Plains – Texas transfer) relative growth from the 2020 system (*see* Figure ES-6). Again, cross-interconnection transfers show the largest relative growth in anticipated need. Scenarios which include high load growth are more in line with state and utility policy goals in some regions than the moderate load growth scenarios.



Note: Median and interquartile range of within-region transmission results given two different sets of scenarios for six different recent capacity expansion models. Currently installed transmission and transfer capacity as pictured from Denholm et al. (2022a).

Figure ES-5. Anticipated future within-region transmission need in 2035 for the Moderate/High and High/High scenario groups.

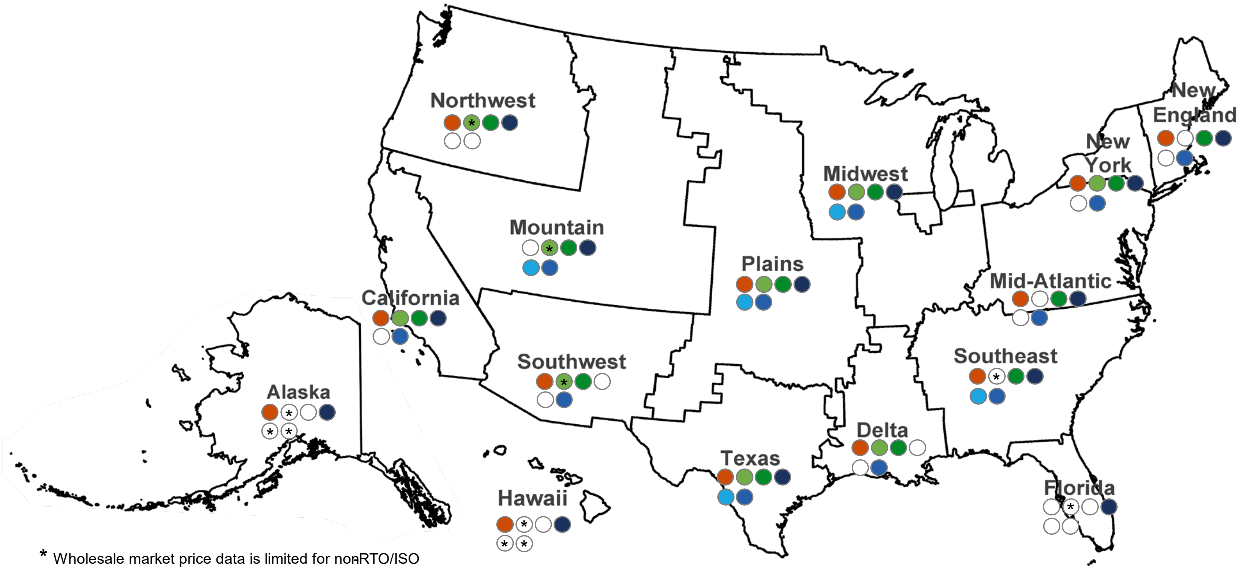


Note: Median and interquartile range of interregional transfer results given two different sets of scenarios for six different recent capacity expansion models. Currently installed transmission and transfer capacity as pictured from Denholm et al. (2022a).

Figure ES-6. Anticipated future interregional transfer capacity need in 2035 for the Moderate/High and High/High scenario groups.

Summary of Current and Anticipated Transmission Needs by Geographic Region

Figure ES-7 summarizes findings of current and anticipated transmission needs by geographic region as determined by the data and studies referenced in the Section IV discussion of historical market conditions, Section V literature review, and Section VI national capacity expansion modeling results analysis. The different color circles located on the map of Figure ES-7 (top) correspond to the transmission needs listed in the dashboard (bottom).



* Wholesale market price data is limited for non-RTO/ISO regions and capacity expansion modeling data is limited for Alaska and Hawaii. Absence of data does not necessarily indicate that there is no need for new transmission.

Region

		California	Northwest	Mountain	Southwest	Texas	Plains	Midwest	Delta	Southeast	Florida	Mid-Atlantic	New York	New England	Alaska	Hawaii
Current or Anticipated Need	Improve reliability & resilience	●	●		●	●	●	●	●	●		●	●	●	●	●
	Alleviate congestion & unscheduled flows	●	●*	●*	●*	●	●	●	●	*	*		●		*	*
	Alleviate transfer capacity limits between neighbors	●	●	●	●	●	●	●	●	●		●	●	●		
	Deliver cost-effective generation to meet demand	●	●	●		●	●	●		●	●	●	●	●	●	●
Anticipated Need	Meet future generation & demand with within-region transmission			●		●	●	●		●					*	*
	Meet future generation & demand with interregional transfer capacity	●		●	●	●	●	●	●	●		●	●	●	*	*

Source: See Supplemental Material for supporting references and methodology.

Figure ES-7. Summary of current and future transmission needs identified in Needs Study by geographic region.

Acronyms and Abbreviations

AEA	Alaska Energy Authority
ATC	available transfer capability
BA	balancing authority
CAISO	California ISO
DER	distributed energy resource
DLR	dynamic line rating
DOE	U.S. Department of Energy
ERCOT	Electric Reliability Council of Texas
EIA	Energy Information Administration
EROS	Earth Resources Observation and Science
FERC	Federal Energy Regulatory Commission
FPA	Federal Power Act
GMO	Geospatial Management Office
HVDC	high-voltage direct current
IESO	Independent Electricity System Operator of Ontario
IIJA	Infrastructure Investment and Jobs Act
IQR	interquartile range
IRA	Inflation Reduction Act
ISO	independent system operator
ISO-NE	ISO New England
JTIQ	Joint Transmission Interconnection Queue
KIUC	Kaua'i Island Utility Cooperative
LRTP	Long-Term Regional Transmission Plan
MISO	Midcontinent Independent System Operator
NEPA	National Environmental Protection Agency
NERC	North American Electric Reliability Corporation
NIETC	National Interest Electric Transmission Corridors
NRCS	Natural Resources Conservation Service
NREL	National Renewable Energy Laboratory
NYISO	New York Independent System Operator

PFC	power flow controllers
R&D	research and development
RAPID	Regulatory and Permitting Information Desktop
RTO	regional transmission organization
SEEM	Southeastern Energy Exchange Market
SEMA	Southeastern Massachusetts
SPP	Southwest Power Pool
TLR	transmission loading relief
TVA	Tennessee Valley Authority
VER	variable energy resources
WECC	Western Electricity Coordinating Council
WEIM	Western Energy Imbalance Market
WEIS	Western Energy Imbalance Service
WIUFMP	Western Interconnection Unscheduled Flow Mitigation Plan

NATIONAL TRANSMISSION NEEDS STUDY

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I. Introduction

A robust transmission system is critical to the Nation's economic, energy, and national security, and the U.S. Department of Energy (the Department or DOE) is using a variety of tools to address challenges to expanding and upgrading the nation's transmission infrastructure to meet current and future needs.[3] As one part of that effort, DOE undertakes this Needs Study to identify 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.[4] For example, the results of this needs assessment can inform DOE's work implementing various provisions of the Infrastructure Investment and Jobs Act[5] (IIJA) and the Inflation Reduction Act relating to transmission expansion, grid resilience, and grid technology. This Needs Study will also support the implementation of existing Department programs, including the Department's numerous funding programs, technical assistance and broader transmission planning activities, and the potential designation of National Interest Electric Transmission Corridors (NIETC, pronounced \NIT-see\). DOE expects that this Needs Study will also help inform existing industry-led transmission planning processes, including the regional transmission planning processes conducted in accordance with Federal Energy Regulatory Commission (FERC) regulations and policies.

One of the underlying authorities for this Needs Study is Section 216 of the Federal Power Act (FPA), which as amended directs DOE and FERC to take specific actions aimed at accelerating electric transmission development. Section 216(a)(1) of the FPA directs the Department to conduct assessments of national electric transmission capacity constraints and congestion not less frequently than once every 3 years.[6] Pursuant to Section 216(a)(1) and (3) of the FPA, DOE has initiated and will continue to consult with affected states, Indian Tribes, and appropriate regional entities. Section 216(a)(2) of the FPA directs DOE to issue a report based on the study conducted under Section 216(a)(1) or other information related to electric transmission capacity constraints and congestion, which may designate one or more NIETCs.

This Needs Study does not designate NIETCs. In accordance with Section 216(a)(2), DOE may issue a report that designates a NIETC in a geographic area that is experiencing or is expected to experience electric energy transmission capacity constraints or congestion that adversely affects consumers. Such a report would be based on the information included, and the findings made, in this Needs Study and other information relating to electric energy transmission

[3] U.S. Department of Energy, Building a Better Grid Initiative to Upgrade and Expand the Nation's Electric Transmission Grid to Support Resilience, Reliability, and Decarbonization, 87 Fed. Reg. 2769 (Jan. 19, 2022), https://www.govinfo.gov/content/pkg/FR-2022-01-19/pdf/2022-00883.pdf.
[4] As noted in the Notice of Intent for the Building a Better Grid Initiative, DOE intends to launch a coordinated transmission deployment program to implement both IIJA and previously enacted authorities through studies and funding. The notice provided further background on the Department's tools and authorities to accelerate transmission deployment. See 87 Fed. Reg. at 2770–73.
[5] Infrastructure Investment and Jobs Act, Pub. L. No. 117-58, 135 Stat. 429 (2021).
[6] See 16 U.S.C. 824p.

capacity constraints or congestion. Prior to issuing its report designating a NIETC, DOE would consider alternatives and recommendations from interested parties (including an opportunity for comment from affected states and Indian Tribes). Section 216(a)(4) lists other factors that the Department may consider in determining whether to designate a NIETC, including the energy independence and energy security of the United States and reduction in the cost of electric energy for consumers.[7] On May 15, 2023, the Department published a Notice of Intent and Request for Information (RFI) in which it explained its intent to evaluate the designation of NIETCs on a route-specific basis and requested public comment on this proposal.[8] After evaluating comments to this RFI and giving the matter due consideration, DOE expects to issue guidance on the process it will use to designate NIETCs.

Although this Needs Study builds on findings from previous congestion studies (DOE 2020a), its scope has expanded because amendments to FPA Section 216 enacted in the IIJA require examination of both current and expected transmission capacity constraints and congestion. Consequently, this Needs Study includes an analysis of historical and anticipated electric transmission needs, defined as 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 transmission 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.

This report is being disseminated by the Department of Energy. As such, this document was 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 of Energy.

I.a. How to Use This Needs 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.[9] 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.

[7] See note 16, infra, and accompanying text for further discussion of FPA Section 216(a)(4).
[8] U.S. Department of Energy, Notice of Intent and Request for Information: Designation of National Interest Electric Transmission Corridors (May 15, 2023), 88 Fed. Reg. 30956.
[9] Transmission planning is predominantly conducted today by local utilities, who plan for transmission needs on their respective transmission systems, and 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. *See* Order No. 1000, 136 FERC ¶ 61,051.

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 need 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 cross-cutting value. 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 by findings and resources in this Needs Study, holistic, multivalue transmission expansion planning can allow for transmission solutions to meet multiple planning objectives and can lead to a more efficiently planned, cost-effective bulk power system.[10]

This Needs Study also provides an assessment of anticipated transmission needs and value under various future transmission system considerations, including forecasted increases in variable energy generation, extreme weather events, and load growth, among others. For example, findings highlight the complexities of planning for future energy systems with increased variable and distributed energy resources (DERs) that are due to policy and consumer demand drivers and the value of transmission in accommodating such a future resource mix. Similarly, recent experience with extreme weather events demonstrates that planning for the bulk power system needs to extend beyond the footprint of individual utilities or regions to provide assurance that energy can be delivered from where it is available to where it is needed to mitigate risks associated with common mode failures. The Department notes transmission planning entities may use these Needs Study findings as an informative basis to conduct more granular, scenario-based transmission studies with longer planning horizons to inform more comprehensive planning assessments.[11] Transmission planning efforts may also consider the findings of this Needs Study to reevaluate the historic weather data used in system planning and ensure it includes the type and frequency of extreme 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 aggregated 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.

In addition to assessments of transmission need and benefits, this Needs Study recognizes and considers additional factors not traditionally captured by more narrowly focused transmission planning processes, including flexibility and optionality considerations. As a result, the

[10] *See also* DOE discussion of incorporating a wider set of transmission benefits and evaluation of portfolios in transmission planning efforts in comments filed in response to FERC's Advance Notice of Proposed Rulemaking in Docket No. RM21-17-000, "Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection," available at: https://elibrary.ferc.gov/eLibrary/filedownload?fileid=D8C2B9C9-DA24-CE62-9C9F-835CB6700000.

[11] *See id.* for additional DOE discussion of long-range, scenario-based transmission planning benefits.

Department notes transmission planning entities may wish to consider alternative transmission solutions as part of existing planning processes.[12] For example, alternative transmission solutions, such as grid-enhancing technologies, have been deployed on the existing grid to enhance asset utilization, mitigate curtailments of generation resources, and better manage congestion patterns. Leveraging emerging technologies to increase operators' visibility of power system flows and status of critical components can serve to improve grid security while maintaining reliability and making capacity available to alleviate constraints at lower cost.

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, as well as their ability to influence regional planning authority transmission planning decision-making through participation in stakeholder processes. Further, states and local governments would also benefit from incorporating the findings contained in this Needs Study in their respective transmission siting and approval processes. As demonstrated by 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.[13]

I.b. Study Organization

This study is organized as follows:

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

Section III introduces the role of transmission in the power system, benefits provided by transmission, and challenges to transmission expansion. The section 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

[12] *See id.* for additional DOE discussion of additional factors, including technology trends, which transmission planners may consider incorporating into transmission planning efforts.

[13] *See id.* for additional DOE discussion of the importance of accommodating a diversity of jurisdictional interests, including those at the state level, in transmission planning efforts.

congestion. It then reviews regional variations in the approaches used to manage congestion and resolve capacity constraints.

Section IV discusses trends in transmission investments and what they indicate about transmission infrastructure needs. The section reviews several metrics assessing historical transmission investment, including load-weighted capital investment in new transmission and circuit-miles of transmission. It then examines historical market price differentials and wholesale market prices within and across regions to understand trends in congestion and quantify the value of interregional transmission. Finally, the section presents data from generation interconnection queues to further demonstrate the need for new transmission infrastructure.

Section V synthesizes DOE's key findings from a literature review of the historical and anticipated drivers, benefits, and challenges of expanding U.S. transmission infrastructure. The reports and literature reviewed by DOE are from a wide variety of sources and a cross section of the electricity sector. Common topics across reviewed reports include reliability and resilience, regional congestion, generation and load concerns, alternative transmission solutions, and siting and land use considerations.

Section VI outlines anticipated future transmission needs from the results of available national capacity expansion models encompassing multiple scenarios of potential future demand and clean energy growth. The section details electricity demand and generation assumptions across scenarios and the resulting need for regional deployment of transmission and interregional transfer capacity expansion under a wide variety of potential futures.

Section VII reviews the Department's process in preparing this study. The section describes the Department's consultation with states, Indian Tribes, and regional entities on a consultation draft of the study, as required by FPA Section 216. It further describes the process by which the Department solicited public feedback, including a list of entities who submitted comments during the public comment period.

Appendix A provides fact sheets for the nation as a whole as well as individual regions. These fact sheets are intended to summarize high-level Needs Study findings for wide audiences.

Appendix B provides a synthesis of the comments received on the draft Needs Study during the public comment period and the Department's response to those comments. All comments received during the public comment period can be found on the Department's website, as described in Section VII.

Supplemental Material, which contains supporting information about regional and interregional congestion and further detail on the capacity expansion modeling studies used to discuss anticipated transmission need, can be found online to accompany this Needs Study.[14]

[14] Supplemental Material and more information related to this Needs Study can be found at https://www.energy.gov/gdo/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 IIJA directs the Secretary to establish several programs for grid infrastructure resilience and reliability, including, but not limited to, 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). The Inflation Reduction Act also includes relevant authorities, including Section 50151 (Transmission Facility Financing); Section 50152 (Grants to Facilitate the Siting of Interstate Electricity Transmission Lines); and Section 50153 (Interregional and Offshore Wind Electricity Transmission Planning, Modeling, and Analysis).

Further, Section 40105 of the IIJA amends 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.[15] As the purpose and underlying authority of this Needs Study is broad, the scope of this study is not constrained solely to the analytical direction set forth in Section 216(a)(1) of the FPA. The Needs Study can also assist the Secretary in evaluating the criteria necessary for designation of a National Interest Electric Transmission Corridor (NIETC), as provided by Section 216(a).[16] Section 216(a)(2) of the FPA directs DOE to issue a report, which may designate a NIETC(s) 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, DOE maintains existing authorities to 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

[15] 16 U.S.C. 824p(a)(1).

[16] 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).

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 Loan Programs Office[17] and Transmission Infrastructure Program.[18]

Lastly, to ensure the federal government, states, and the public have access to and can obtain reliable energy information, Congress granted the Secretary broad authorities to collect and study information as the Secretary determines necessary to help formulate energy policy.[19] This broad grant of authority is in addition to, and not in limitation of, any other authority of the Secretary.

[17] 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.
[18] 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. *See* https://www.wapa.gov/transmission/TIP/Pages/AboutTIP.aspx.
[19] *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, the section reviews regional variations in the approaches historically used to manage congestion in the Eastern and Western U.S. Interconnection transmission systems. The congestion management practices include:

- Centralized unit commitment and economic dispatch procedures used in areas operated by regional transmission organizations (RTOs) and independent system operators (ISOs) (together, RTO/ISO);
- Transmission services 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.

Unlike prior studies, this Needs Study does not review historic ATC and TLR data in identifying persistent congestion, except where 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.[20] 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.

The WIUFMP was used for the first time in this Needs Study to identify congested areas in the Western Interconnection. Accepted by FERC in March 2016, the Plan monitors real-time flows on selected transmission paths where congestion is significant and could affect grid reliability, and it uses control devices and curtailment to manage congestion and unscheduled flows on the grid.

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 load centers 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 United States, transmission lines are typically rated between 69 kilovolts

[20] 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 occurred persistently. FERC (2016) provides a discussion of congestion metrics based on transmission loading relief and on wholesale electricity price differentials.

(kV) and 765 kV, although exceptions can occur depending on the function of the line.[21] 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 systems necessary for operating an interconnected electric energy transmission network or any portion thereof (NERC 2023).

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 wires and alternative transmission solutions 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 addition of new infrastructure—such as transmission lines, substations, and transformers—or through rebuilds using components that provide higher ratings.

Transmission infrastructure improvements provide several benefits to consumers. Transmission improves grid reliability, resource adequacy, and resilience of the power system. Transmission 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 helps support resource adequacy and reliability; this diversity can typically be improved with increased transmission infrastructure, so long as regional planners consider and address the risks of interdependency between regions. New transmission advances clean energy goals by enabling greater access to the best available and lowest cost clean energy resources, which can be in remote areas far from load and the existing transmission system. Many new energy resources that would help reduce power prices and meet reliability and clean energy goals are currently within backlogged interconnection queues and a more efficient transmission study process can help hasten connection of those resources to the grid. In areas with high generation resource penetration, transmission buildout can reduce resource generation curtailment and improve the output of renewable resources. A more robust transmission system—along with associated upgrades to the distribution system—supports the electrification of end-use devices that currently rely on fossil fuel combustion, resulting in environmental benefits in the form of improved air quality and avoided adverse health effects. 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.

[21] 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 2022b).

Expanding transmission capacity, however, can be challenging. Navigating complex state processes and meeting federal and local requirements in efforts to permit and site new lines can be difficult and can result in long development periods. The problems are compounded for regional projects that cross multiple states and jurisdictions. Deciding who pays the cost of transmission capacity expansion is another challenge, one 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. Transmission projects also frequently face public opposition or “not-in-my-backyard” concerns 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 considered to be the existence of present or expected electric transmission capacity constraints or congestion in a geographic area.

Transmission congestion. *Transmission congestion*[22] refers to the economic impacts on the users of electricity that result from operation of the system within the physical limits on the amount of electricity flow the system is allowed to carry to ensure safe and reliable operation (otherwise known as a *transmission constraint*[23]). 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.

A constraint on the transmission system that may drive transmission congestion could refer to:

- 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.

[22] Energy Information Administration (EIA) defines *congestion* as “a condition that occurs when insufficient transfer capacity is available to implement all of the preferred schedules for electricity transmission simultaneously.” (EIA 2022b)
[23] 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 2022b) (EIA 2022b)

Transmission constraints. *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—as defined above (in the second case)—to the permissible flow of electricity over the affected element(s) under specific operating conditions, to ensure safe and secure operations in compliance with reliability rules.[24] 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. As electricity flows through a line, it heats the line. The thermal limit is based on the operating temperature 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, substation voltages must be 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 on the basis of system conditions.
- Stability limits: System stability refers to the ability of the power system to return to a stable operating point 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 frequency deviation tolerances during normal operations. In the United States, the bulk power system is operated at a nominal frequency level of 60 Hertz (Hz). Frequency deviations can occur when the operating frequency deviates outside the tolerance around 60 Hz (over or under frequency) or when voltage and current waveforms are not synchronized (phase deviations). Stability limits might be required to ensure that the power flow does not exceed levels that could pose a risk to system operations.

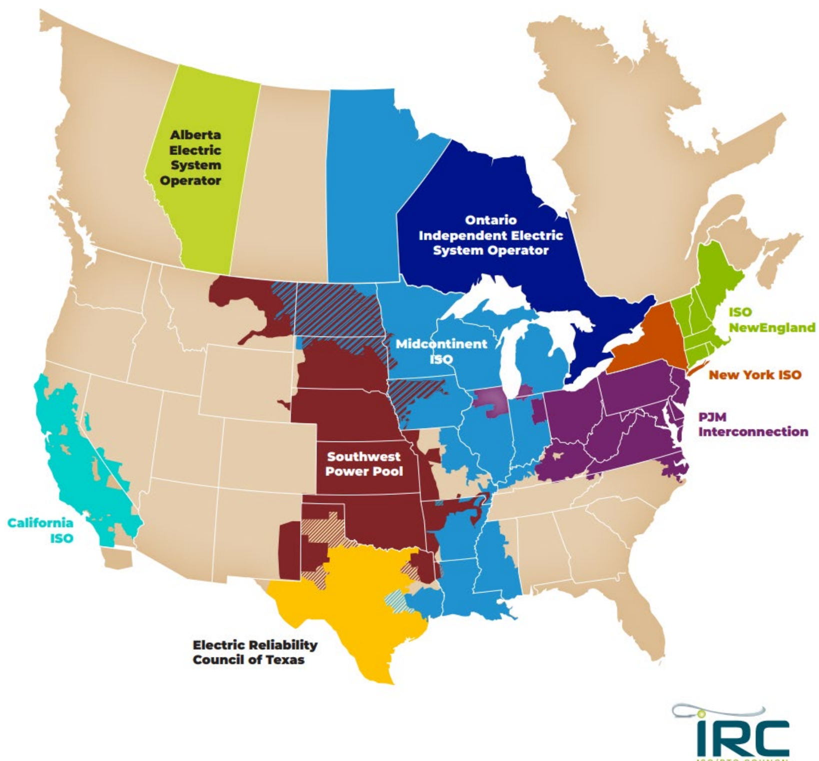
A fundamental responsibility of transmission system operators is to ensure reliable operation of the transmission system within these limits. This responsibility is executed by referring to transmission operating limits when approving or denying transmission service requests by parties seeking to use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

[24] 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 2022b).

Transmission capacity constraint. While *transmission congestion* (and the related but not identical *transmission constraint)* have industry standard definitions, *transmission capacity constraint* does not. We define it here to be a suboptimal limit of transfer of electric power on the grid, including those that reduce operational reliability of the power system; power transfer capability[25] or capacity[26] limits between neighboring regions that reduce resilience or increase production costs; and limits on the ability of cost-effective generation to be delivered to high-priced demand.

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 United States and two RTOs/ISOs in Canada operate on the North American power grid. Figure III-1 shows the illustrative boundaries of each organization.



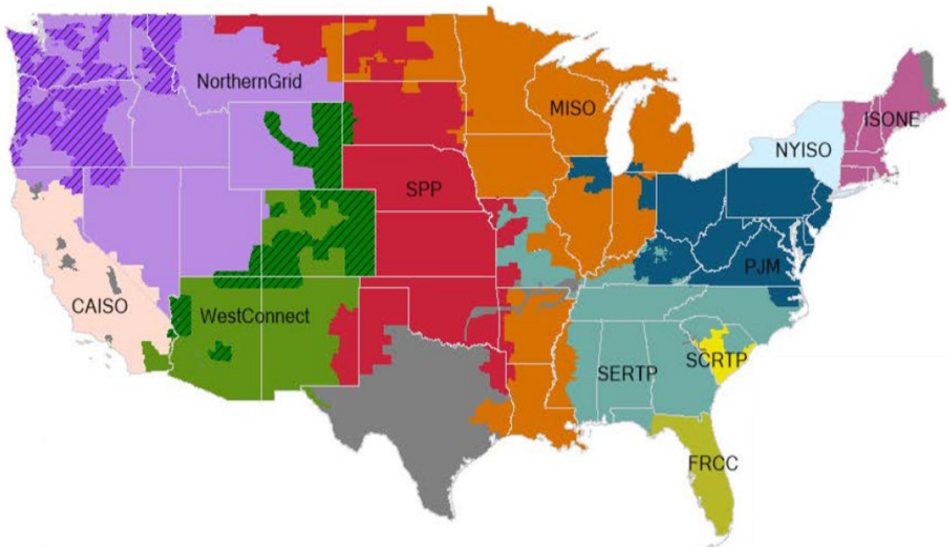
Source: ISO/RTO Council, at https://isorto.org/.

Figure III-1. Regional transmission organization/independent system operator footprints.

[25] Transfer capability is defined in NERC (2022b) 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."

[26] 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.

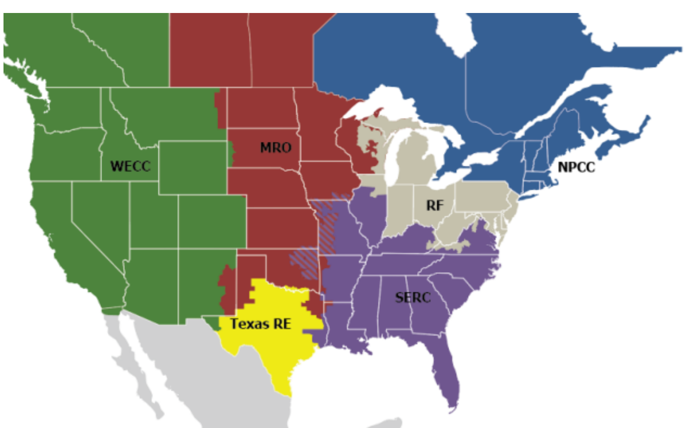
Regional transmission planning occurs within the FERC Order 1000 Transmission Planning Regions (Order 1000 regions) and the Electric Reliability Council of Texas (collectively, transmission planning entities). The seven U.S. RTOs/ISOs serve as Order 1000 regions in their territories. The Order 1000 regions for 2021 are shown in Figure III-2.



Source: Federal Energy Regulatory Commission at https://www.ferc.gov/media/regions-map-printable-version-order-no-1000.

Figure III-2. Federal Energy Regulatory Commission Order 1000 regions.

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



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

Source: North American Electric Reliability Corporation (NERC 2021).

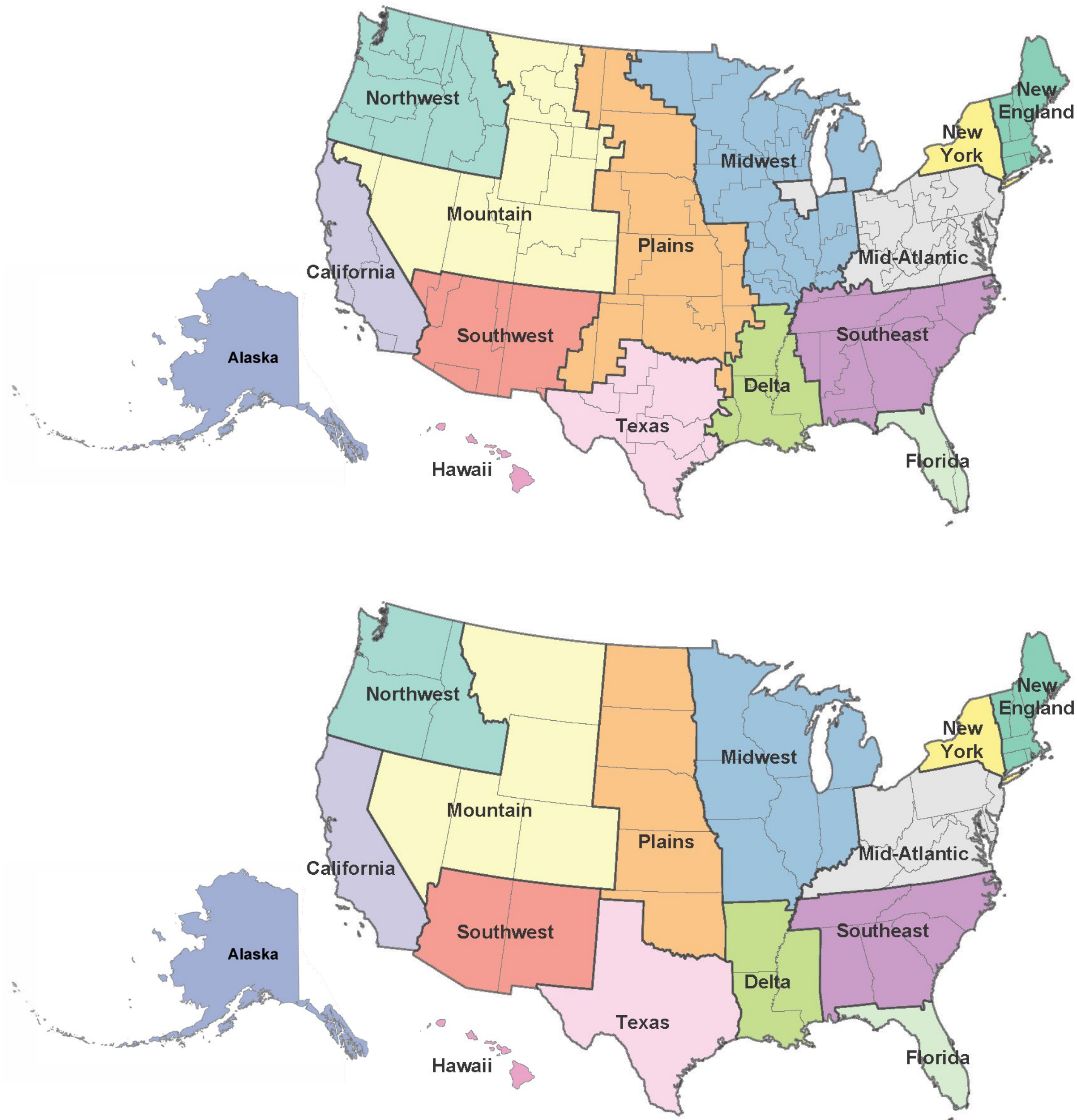
Figure III-3. Regional reliability entities.

This study organizes transmission need results by geographic region, to the extent possible. 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. For example, the wholesale market prices that underlie the analysis presented in Section IV.b. rely on historical prices from the RTOs/ISOs, so those names are used in that section. Otherwise, a geographic naming convention is adopted here. Figure III-4 shows the geographic regions used in this analysis, the boundaries of which were chosen to represent the unique boundaries of the power system entities. Table III-1 identifies the geographic region nomenclature used in this study and the principal power system entity associated with that geographic area for completeness.

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.

Geographic Region	RTO/ISO	Transmission Planning	Reliability Entity
California	California Independent System Operator	California Independent System Operator	Western Electricity Coordinating Council
Northwest	–	Northern Grid	Western Electricity Coordinating Council
Mountain	–	Northern Grid & WestConnect	Western Electricity Coordinating Council
Southwest	–	WestConnect	Western Electricity Coordinating Council
Texas	Electric Reliability Council of Texas	Electric Reliability Council of Texas	Texas Reliability Entity
Plains	Southwest Power Pool	Southwest Power Pool	Midwest Reliability Organization
Midwest	Midcontinent Independent System Operator	Midcontinent Independent System Operator	Midwest Reliability Organization
Delta	Midcontinent Independent System Operator	Midcontinent Independent System Operator	SERC Reliability Corporation
Southeast	–	Southeastern Regional Transmission Planning & South Carolina Regional Transmission Planning	SERC Reliability Corporation
Florida	–	Florida Reliability Coordinating Council	SERC Reliability Corporation
Mid-Atlantic	PJM	PJM	Reliability First
New York	New York Independent System Operator	New York Independent System Operator	Northeast Power Coordinating Council
New England	ISO New England	ISO New England	Northeast Power Coordinating Council

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 (NERC 2021).



Source: National Renewable Energy Laboratory.

Note: Geographic boundaries that align with the Reliability Entity and the transmission planning entities (top) are used whenever possible. If underlying data were only available at the state-level, then geographic boundaries align with state boundaries (bottom). Alaska is not to scale.

Figure III-4. Geographic regions used to present study results in this analysis, where appropriate.

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 on the basis of 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 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 systems long 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.

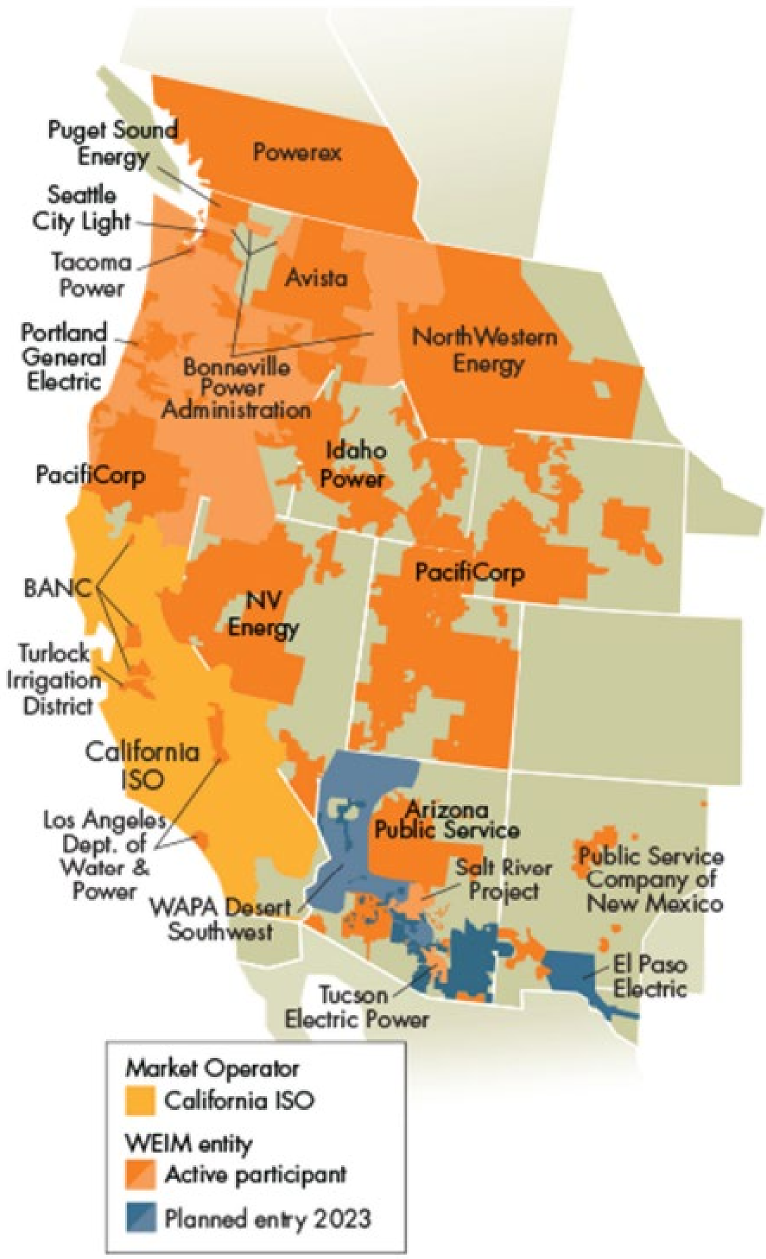
ATC directly reflects how close operation is to a transmission constraint. An ATC value of zero means no further requests for transmission services can be accepted, because no additional flows of electricity can be accommodated without violating a reliability limit.

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. That is, the availability of transmission services is routinely updated. Potential users seeking those services might forego 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 because the ATC had already been set to zero.

The RTO/ISO economic dispatch procedures that serve, in part, to manage congestion in real time are becoming available to the non-RTO/ISO regions through energy imbalance markets or services (Chen 2020). There are three active energy imbalance markets in the United States. In 2014, the California ISO (CAISO) launched the Western Energy Imbalance Market (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 2022, WEIM had expanded to include market participants in all states in the Western Interconnection except Colorado (*see* Figure III-5). Southwest Power Pool (SPP) began administering the Western Energy Imbalance Service Market for utilities in the Western Interconnection not currently part of an RTO/ISO in 2020 (SPP 2022). Utilities in the Southeast are in the process of developing the Southeastern Energy Exchange Market (SEEM) to trade energy in real time (SEEM 2022), 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.

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 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.



Source: California Independent System Operator Corporation at https://www.westerneim.com/Pages/About/default.aspx/. Licensed with permission from the CAISO. Any statements, conclusions, summaries, or other commentaries expressed herein do not reflect the opinions or endorsement of the CAISO.

Figure III-5. Western Energy Imbalance Market footprint.

In the Eastern Interconnection, principally but not exclusively in the Southeastern regions served by non-RTOs/ISOs, transmission system operators use the TLR[27] administrative procedure to address congestion that arises in real time.[28] 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 North American Electric Reliability Corporation (NERC).[29]

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 (PacifiCorp 2019).[30] 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 WIUFMP manages congestion on the Qualified Paths using designated Qualified Controllable Devices and using curtailment when necessary. Qualified Controllable Devices are selected on the basis of their effectiveness in reducing unscheduled flows on the Qualified Paths.

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

[28] 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.

[29] See https://www.nerc.com/pa/rrm/TLR/Pages/TLR-Logs.aspx.

[30] Revision 4 of the Western Interconnection Unscheduled Flow Mitigation Plan was filed with FERC by PacifiCorp on August 9, 2019, in Docket No. ER19-2566 (PacifiCorp 2019). The revised plan was accepted by FERC on October 9, 2019. The mitigation plan can be found online in FERC’s Docket eLibrary at https://elibrary.ferc.gov/. The mitigation plan is also hosted by SPP at https://www.spp.org/documents/62460/081919%20wiufmp%20tariff.pdf.

IV. Current Transmission Need Assessment through Historical Data

Several indicators point to an immediate need for more transmission infrastructure. For example, wholesale market price differences across geographic locations directly assess the impact of congestion on the transmission system. Additional transmission could remove or reduce the variation in prices caused by congestion, allowing lower cost energy to reach high-demand areas. Examining price differences between RTOs/ISOs can also help identify the need for additional interregional transmission capacity to alleviate congestion and constraints negatively impacting consumers. Interregional transmission further supports the development of within-region transmission because load and generation patterns across multiple regional markets are less temporally correlated than within different subregions of a single market.

Furthermore, over the past several years, installation of new generators has been delayed because of longer wait times for interconnection agreements (Rand et al. 2022) and increased costs to connect to the electricity grid (Caspary et al. 2021). As described in the FERC Notice of Proposed Rulemaking, *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection* (FERC 2022), these wait time and cost challenges are related to an increasing portion of overall transmission investment occurring through these interconnection agreement processes, which could result in less cost-effective transmission deployment. FERC suggests that the “piecemeal” approach to transmission deployment that occurs with the interconnection agreement process will not benefit from the economies of scale that would accompany a full regional transmission planning process (FERC 2022).

This section explores recent trends in transmission investments and what they reveal about current transmission need. Section IV.a. reviews the past decade of transmission investments in each U.S. region guided by metrics as outlined in the *2017 Transmission Metrics Report* (FERC 2017). Section IV.b. considers transmission congestion that currently exists within each region by analyzing historical market price differentials across the contiguous United States. Section IV.b. further analyzes differences in simultaneous wholesale market prices between neighboring regions to quantify the congestion value of interregional transmission. Section IV.c. discusses qualified paths in the Western Interconnection. Section IV.d. presents nearly 20 years of historic data from the interconnection queues, demonstrating the amount of generation waiting to be connected to the grid.

IV.a. Historical Transmission Investments

In 2016, FERC developed several metrics to assess historical transmission investment (FERC 2017). Two of these metrics show historical transmission investments—in terms of cost and circuit-miles—of projects installed annually in each region. To account for different sizes of the regions, both metrics are weighted by annual regional load.

Transmission investments are inherently “lumpy,” or unevenly distributed. Many projects that have been in development for several years might all be energized in the same year, giving the appearance of large investments during that single year without consideration of when projects first entered the development pipeline. To account for this lumpiness, temporal trends are presented using rolling averages, which differ from the metrics FERC has developed. FERC presented data from 2008 to 2015 in its metrics report (FERC 2017); we consider the decade of investments from 2011 to 2020.[31]

Transmission investment decreased during the second half of the 2010s

Historic investments are measured both in terms of capital costs and circuit-miles of transmission based on the year the transmission project was put into service (i.e., *energized*). Figure IV-1 (top) shows the total annual capital costs of new and rebuilt transmission lines rated at least 100 kV in each region[32] between 2011 and 2020. To account for the inherent lumpiness of transmission investments, this is presented as the simple 3-year moving average of the annual sum of capital costs in each region. Capital costs for all interregional lines that terminate in different regions, or nations, are shown separately from those lines that begin and end in the same region. Figure IV-1 (bottom) shows the same information weighted by regional annual net load; that which is delivered by the transmission system and does not include behind-the-meter generation. The load-weighted costs for all regional and interregional projects are also shown ("Entire U.S.").

Figure IV-2 shows the total annual circuit-miles of the same transmission lines over the same time period as Figure IV-1. The decadal averages for all four metrics in each region are shown as horizontal lines in Figure IV-1 and IV-2, and listed in Table IV-1. It is important to note that the load-weighted capital costs shown in Figure IV-1 and Table IV-1 differ from the total transmission investments utilities in a given region may spend on an annual basis. The metrics presented here are focused on the capital costs of transmission lines that are energized in each year, which do not incorporate the ongoing development costs of those projects that will be energized in future years or the operation and maintenance costs of projects that are already in service.

Transmission investments steadily increased for the United States as a whole during the first half of the decade, followed by several years of decreased energization: an additional 560 circuit-miles were installed each year from 2011 to 2015 nationwide, but the rate of annual installs between 2016 and 2020 actually decreased to a negative 79 circuit-miles per year. The general year-over-year trends for project capital costs match those of circuit-mile investments in each region. Differences between the two metrics can be attributed to differences in

[31] Only a decade of regional transmission investments were analyzed, so any investments made prior to 2011 or after 2020 are not shown. Section VI of this report provides the total regional transmission capacity (terawatt-miles) in 2020 from (Denholm et al. 2022). The regions with the most transmission capacity in 2020 are the Northwest, Mid-Atlantic, Midwest, and Southeast, respectively. A comparison of cumulative regional transmission capacity can provide insights when combined with the annual investments presented in this section. For example, the high 2020 regional transmission capacity suggests that the Southeast—which installed few circuit-miles of transmission between 2011 and 2020—made large transmission investments prior to 2011.

[32] Hawaii is not shown in Figure IV-1 or IV-2 because no transmission projects were energized (MapSearch 2023).

transmission costs per mile across regions—driven by differences in terrain, population densities, etc.

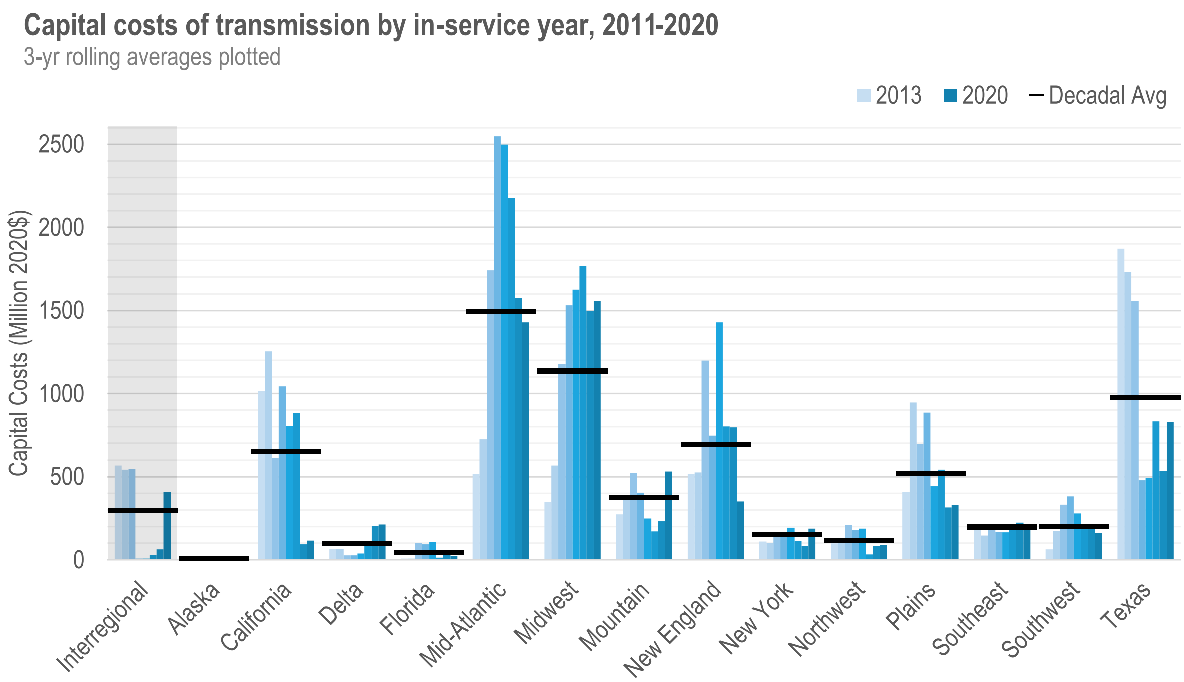
Investments in most regions—notably the Mid-Atlantic, Mountain, Plains, Southwest, and Texas—and interregional projects followed this overall national trend of increasing investments during the first half of the decade and decreasing investments during the second half. Some regions—notably California, Delta, and Midwest—steadily increased transmission capital cost investments through most of the decade. Texas built more circuit-miles than any other region in the first half of the decade. Alaska installed nearly 65 circuit-miles of transmission in 2014 and 2015, a relatively large investment compared with the annual load of the state. The Delta, Southeast, and Florida regions installed the fewest circuit-miles, relative to regional load, throughout the decade.

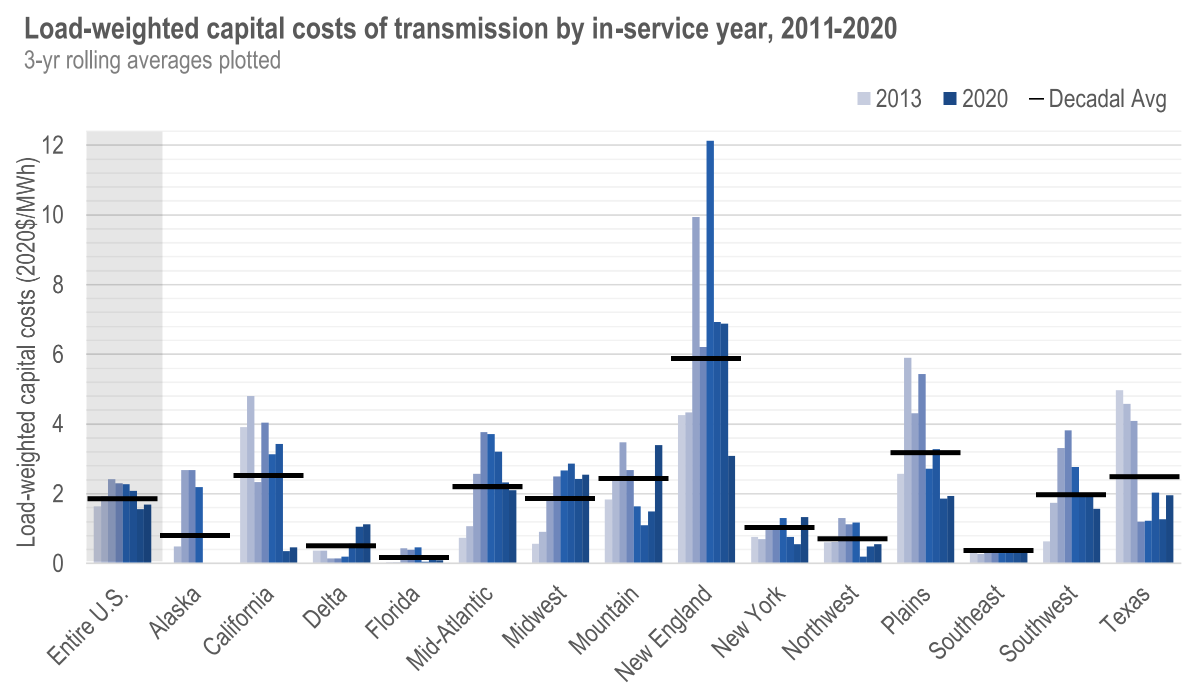
These investments resulted in a national total of 33,000 circuit-miles of either newly constructed or rebuilt transmission lines rated above 100 kV, which were energized between 2011 and 2020. Of these, 20,000 circuit-miles were higher capacity lines rated at least 345 kV (MAPSearch 2023).

Table IV-1. Decadal average of annual sums of capital costs and circuit-miles—load weighted and not—for new and rebuilt transmission rated over 100 kV and energized between 2011 and 2020 across the entire U.S. and in each region individually.

Region	Capital Costs (Million 2020$)	Load-Weighted Capital Costs (2020$/MWh)	Circuit-Miles (ckt-mi)	Load-Weighted Circuit-Miles (ckt-mi/TWh)
Entire U.S.	6,900	1.8	3,300	0.88
Interregional	290	N/A	72	N/A
Alaska	5.0	0.81	4.6	0.75
California	650	2.5	96	0.37
Delta	95	0.51	41	0.22
Florida	41	0.17	21	0.09
Mid-Atlantic	1,500	2.2	360	0.53
Midwest	1,100	1.9	670	1.1
Mountain	370	2.4	260	1.7
New England	690	5.9	150	1.3
New York	150	1.0	100	0.68
Northwest	110	0.70	70	0.43
Plains	520	3.2	410	2.5
Southeast	200	0.37	110	0.21
Southwest	200	2.0	140	1.4
Texas	970	2.5	800	2.1

Source: Transmission data from MAPSearch Transmission Database (2023) and load data from Energy Information Administration State Electricity Profiles (2022c). Rounded to two significant figures.

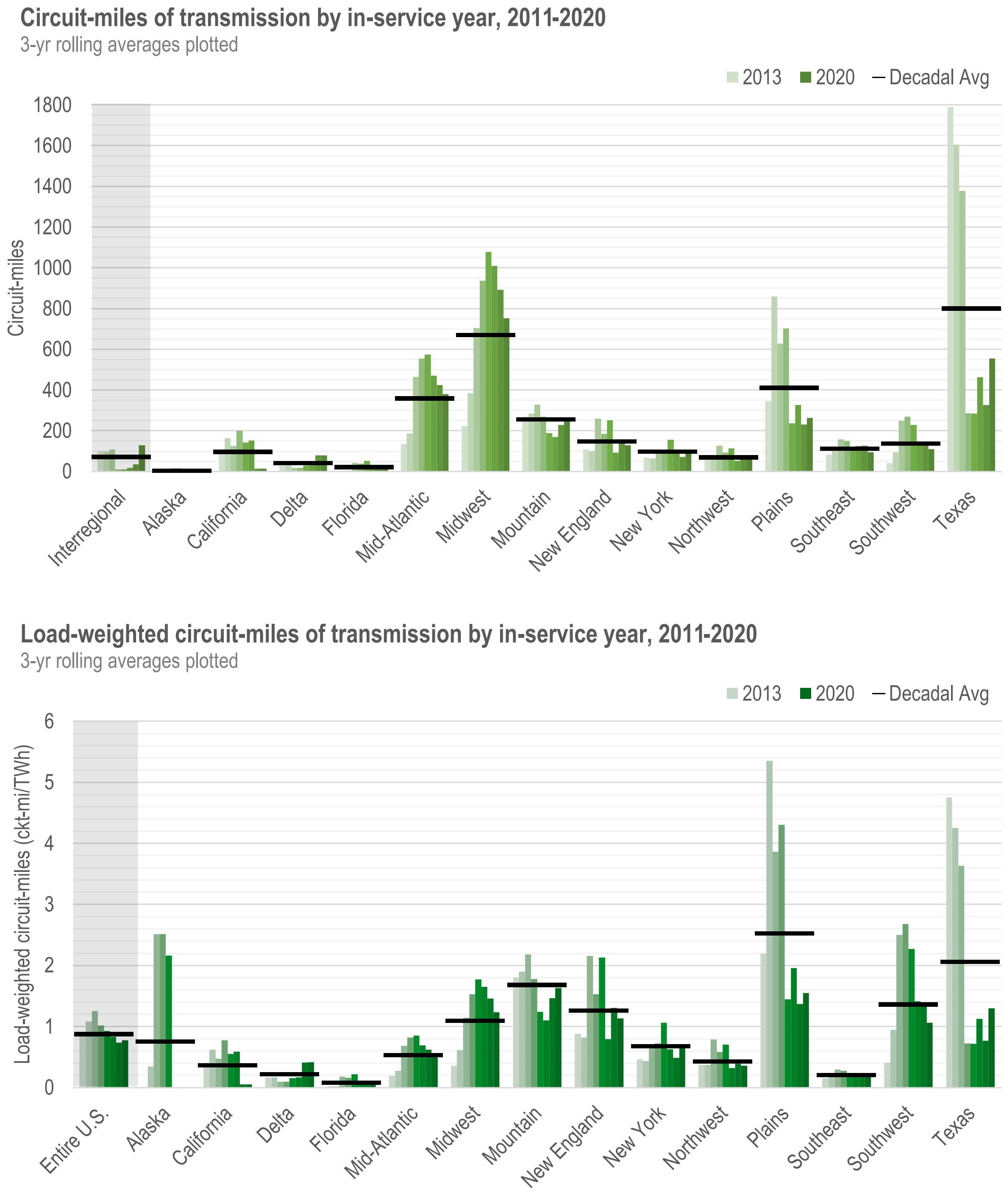




Source: Transmission data from MAPSearch Transmission Database (2023) and load data from Energy Information Administration State Electricity Profiles (2022c). All costs are adjusted to 2020 U.S. dollars using Consumer Price Index from Census (2022).

Note: Interregional costs are for projects that terminate in different regions, including international lines. Load-weighted costs for Entire U.S. encompass both regional and interregional lines.

Figure IV-1. Capital costs (top) and weighted by load (bottom) for new or rebuilt transmission lines (≥100 kV), shown as 3-year rolling averages. Horizontal lines are decadal averages.



Source: Transmission data from MAPSearch Transmission Database (2023) and load data from Energy Information Administration State Electricity Profiles (2022c).

Note: Interregional circuit-miles are for projects that terminate in different regions, including international lines. Load-weighted circuit-miles for Entire U.S. encompass both regional and interregional lines.

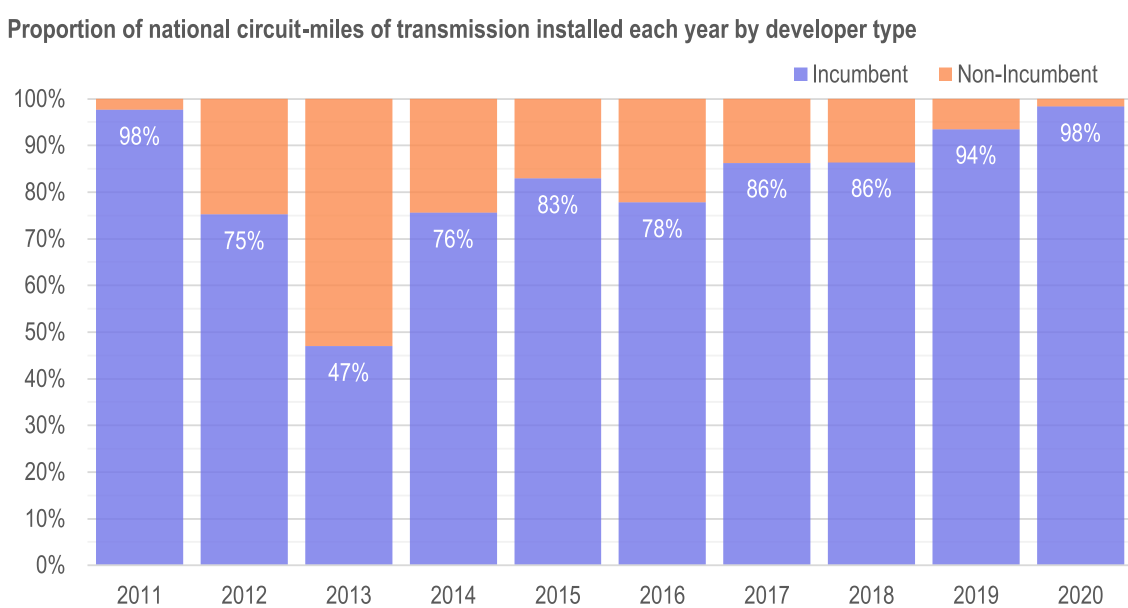
Figure IV-2. Circuit-miles (top) and weighted by load (bottom) for new or rebuilt transmission lines (≥100 kV), shown as 3-year rolling averages. Horizontal lines are decadal averages.

Incumbent utilities installed the majority of transmission facilities

In addition to reviewing trends in total transmission investments, examining trends in who is installing transmission and why is also instructive. Figure IV-3 shows the proportion of new or rebuilt transmission (rated at or above 100 kV) circuit-miles energized each year between 2011 and 2020 by different developer type nationwide. Incumbent transmission developers, or entities that develop transmission within their own retail distribution footprint, have always dominated project development space nationwide. The proportion of project circuit-miles installed by non-incumbent transmission developers—or entities that do not have a retail distribution footprint or that are public utilities developing transmission outside of their footprint—was 25% or less every year of the last decade, with the exception of 2013 when non-incumbent developers were responsible for just over half of all projects energized that year.

Figure IV-4 shows the proportion of new or rebuilt transmission by different developer types by region. Interregional transmission between any two regions is also shown in the figure. (The total transmission circuit-miles installed in each region is shown in Figure IV-7 for reference.) Non-incumbent developers installed the most historic transmission in the Midwest, Plains, and Texas regions. These three regions dominate the national trends shown in Figure IV-3.

Figure IV-5 shows the total circuit-miles of new or rebuilt transmission energized each year by both developer type and nominal voltage rating. Incumbent developers installed more circuit-miles of transmission than non-incumbent developers across all years and voltage classes, except for in the 301–400 kV range in 2013 when installations were equivalent between the two groups. Non-incumbent developers predominantly installed projects in the 301–400 kV range, with some installations at lower voltage ranges. Very few projects higher than 500 kV were installed by any developer in the last decade.



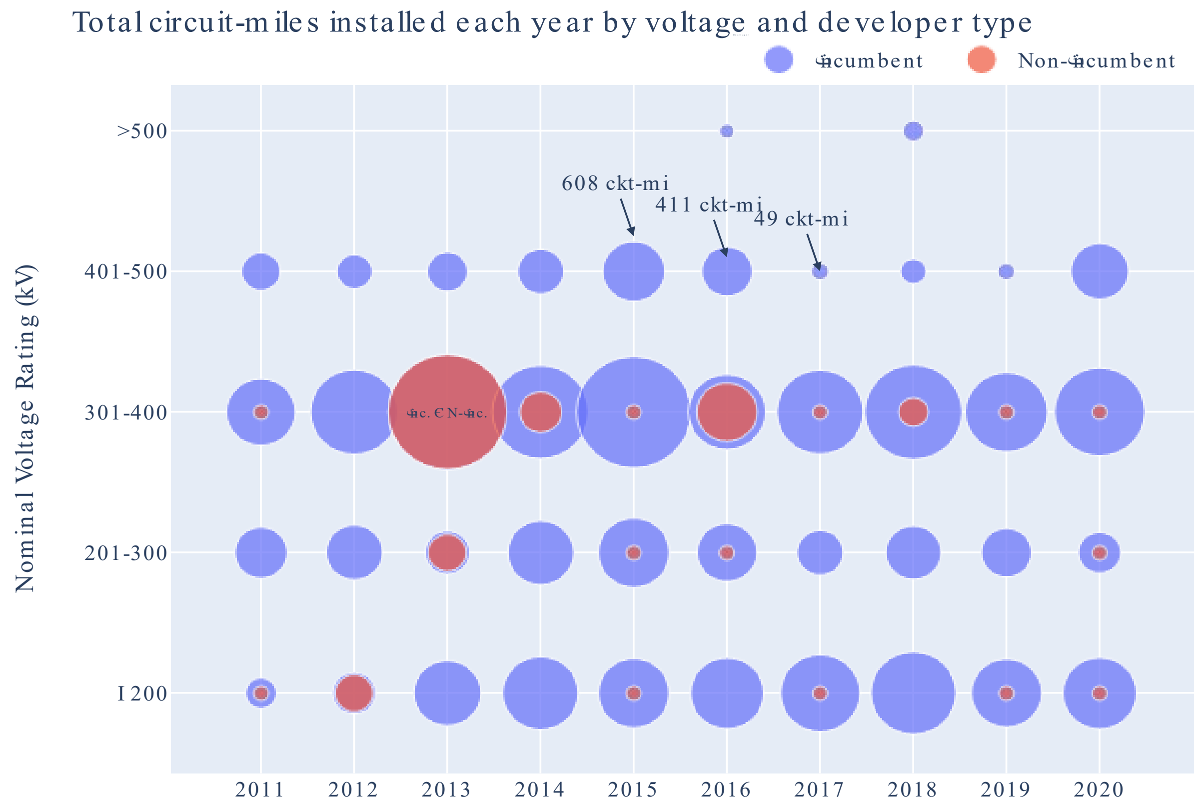
Source: Data from MAPSearch Transmission Database (2023).

Figure IV-3. Proportion of national circuit-miles of new or rebuilt transmission lines (≥100 kV) energized each year by project developer type.

Source: Data from MAPSearch Transmission Database (2023).

Note: Circuit-miles of transmission put in service each year shown in Figure IV-7. Alaska data are not shown due to few years of transmission builds. All Alaska builds were performed by incumbent developers.

Figure IV-4. Proportion of regional and interregional circuit-miles of new or rebuilt transmission lines (≥100 kV) energized each year by project developer type.



Source: Data from MAPSearch Transmission Database (2023).

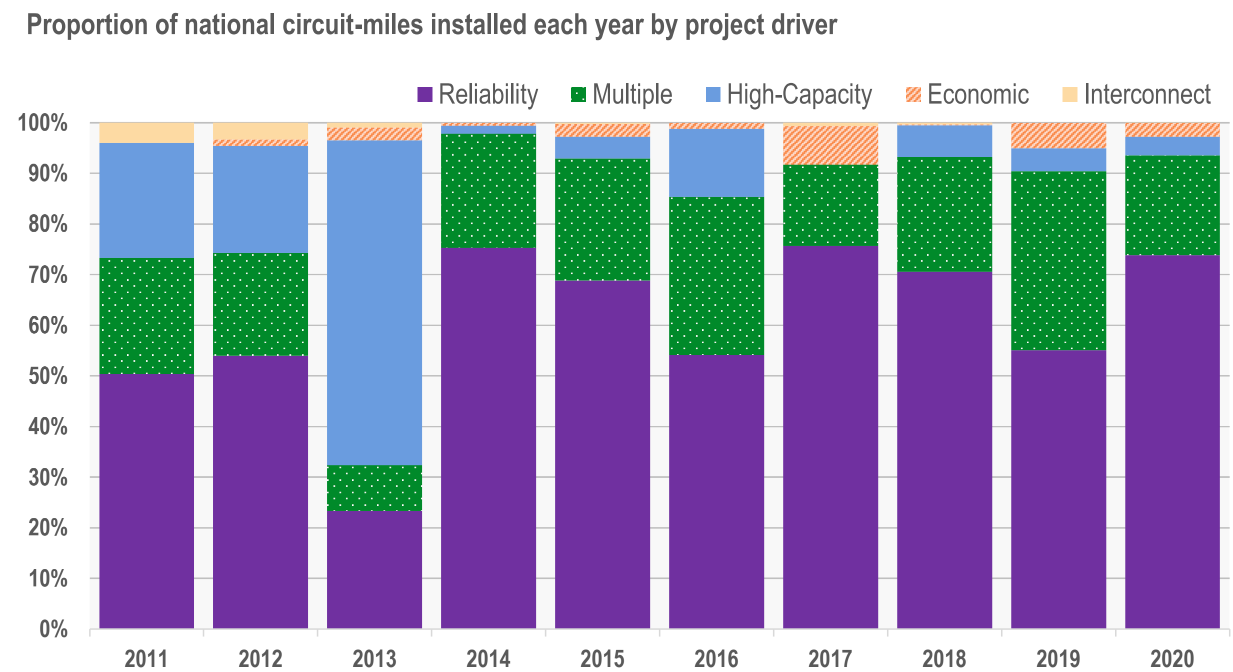
Note: Size of markers indicate total national circuit-miles in each category. Values are explicitly shown for incumbent projects rated between 401 and 500 kV in 2015, 2016, and 2017 for reference. Both incumbent and non-incumbent developers installed equivalent circuit-miles of transmission rated between 301 and 400 kV in 2013.

Figure IV-5. Total national circuit-miles of new or rebuilt transmission lines (≥100 kV) energized each year by voltage rating and project developer type.

Specific reliability needs were the primary driver of transmission investments in most regions

Figure IV-6 shows the primary driver for all new or rebuilt transmission lines (rated at or above 100 kV) energized between 2011 and 2020 across the United States. New transmission projects can be a response to a single or a combination of drivers (*multiple*), including a specific reliability need (*reliability)*, the opportunity to realize production cost savings (*economic*), and the ability to interconnect new generators to the power system (*interconnect*), especially when moving generation long distances over high-capacity power lines, predominantly rated at or above 230 kV (*high-capacity*). The primary driver for a project is identified in transmission planning studies and can be used for cost allocation purposes.

The proportion of overall transmission circuit-miles installed to address specific system reliability needs has grown with time, from 50% in 2011 to 74% in 2020. Economic projects have always had a relatively low share of installed circuit-miles, making up just under a tenth of all projects at their peak in 2017. Projects meant to connect generation resources to the grid at lower voltages have maintained a consistently small proportion of all projects. Lower voltage tie-line projects installed by generation owners to connect their power plants to the nearest available grid substation may not be fully captured in the database used. The proportion of circuit-miles installed to provide high-capacity transmission for connecting generation sources to the grid at high voltages (at least 230 kV) made up 64% of all projects energized in 2013. Projects installed primarily for this purpose dropped precipitously after that year and few circuit-miles have been energized since. The proportion of projects installed nationwide to provide at least two of these drivers was relatively constant—between 20% and 35% most years—over the past decade.



Source: Data from MAPSearch Transmission Database (2023).

*Note: **Reliability** projects are needed to improve the current state of the region's electrical grid. **Economic** projects refer to projects that reduce production costs and lower transmission system congestion or are associated with non-incumbent developers to lease transmission capacity to utilities. **Interconnect** projects connect power generation facilities to the transmission system, regardless of fuel source. **High-capacity** projects are interconnect projects that use higher voltage transmission (at least 230 kV) to connect generation facilities to the grid. **Multiple** projects are those projects that are driven by at least two of the above drivers.*

Figure IV-6. Proportion of national circuit-miles of new or rebuilt transmission lines (≥100 kV) energized each year by project driver.

There are many factors contributing to changes in transmission development throughout the decade. These include state renewable portfolio standards that drove a change of generation from fossil fuel to renewables, transmission expansion to connect those renewables to the bulk electric system, and a strong economy to support the development. Additionally, the Energy Policy Act of 2005 (EPACT 2005) encouraged construction of more renewable resources with tax incentives, particularly for wind and solar, that provided financial support for utilities and others to build clean and renewable generation.

FERC Orders were also influential. Many orders prior to the year 2011 (i.e., 888, 889, 2000, 2003, 2006, 741, 745) drove the creation of wholesale markets and generation competition, which subsequently drove transmission needs. FERC Order 1000 in 2011 directly impacted transmission investments by providing for enhancements to the transmission planning and cost allocation requirements adopted in earlier FERC orders, notably requiring development of regional transmission plans and consideration of alternatives, consideration of transmission needs driven by public policies, and non-incumbent developer reforms.

Inspecting the regional variations in transmission drivers is insightful. Figure IV-7 shows the total circuit-miles of transmission energized each year from 2011 to 2020 in each region. Regional analysis shows that the large proportion of high-capacity projects energized nationwide 2011–2013 (*see* Figure IV-6) were installed almost exclusively in Texas. These projects were installed to enable large amounts of low fuel cost generation identified as part of the Texas Competitive Renewable Energy Zone initiative (NREL 2016).

High-capacity projects energized after 2013 were predominantly installed in the Plains, Southwest, Mountain, and California regions. These transmission lines tell a similar story to the high-capacity lines installed in Texas, namely that the majority of them were installed to interconnect clean energy resources to these regions (e.g., the Palo Verde nuclear facility in the Southwest and Windspeed II in the Plains), access low-cost fuel sources, increase generation portfolio diversity, or meet state clean energy goals.

Economic projects are driven by economic considerations, such as alleviating congestion on the grid that increases prices to consumers. These projects were installed primarily in the Mountain, Midwest, Southwest, and Texas regions. These projects were almost exclusively installed by incumbent developers in the second half of the decade.

Source: Data from MAPSearch Transmission Database (2023).

Note: The scale of circuit-miles shown on the y-axis changes with each row of charts, obscuring the scale of projects relative to other regions. All interregional projects are grouped together and shown separately from regional projects. Project drivers are described in the caption of Figure IV-6.

Figure IV-7. Regional circuit-miles of new or rebuilt transmission lines (≥100 kV) energized each year by project driver.

The Midwest region made sustained investments in projects driven by multiple purposes from 2015 through 2020. Many of these are from the 2011 Multi-Value Project Portfolio, which was a consolidated transmission planning process led by Midcontinent Independent System Operator (MISO) and the states to identify a portfolio of projects that together would deliver multiple benefits and provide regional value (delivering benefits that exceed costs across the region) in meeting economic, reliability and public policy needs (MISO 2012). MISO recently completed a second similar multi-benefit, portfolio-based, transmission planning process, called the Long-Term Regional Transmission Plan (LRTP). The Plains and Mountain regions—and to a lesser extent, the Southwest, Southeast, and Mid-Atlantic regions—also had several years of projects placed in service to meet multiple drivers.

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. Additionally, the Department's Transmission Facility Financing Program—authorized by IRA Section 50151—is a direct loan program for financing transmission projects located within National Interest Electric Transmission Corridors.

Dept. of Energy, Grid Deployment Office, Grid and Transmission Program Conductor Guide, https://www.energy.gov/gdo/grid-and-transmission-program-conductor-guide.

The greatest diversity of transmission project drivers is attributed to the Mountain, Midwest, and Texas regions. The New England, New York, Delta, and Florida regions had the least diversity, installing reliability projects almost exclusively. Interregional projects were also almost exclusively driven by reliability needs.

IV.b. Market Price Differentials

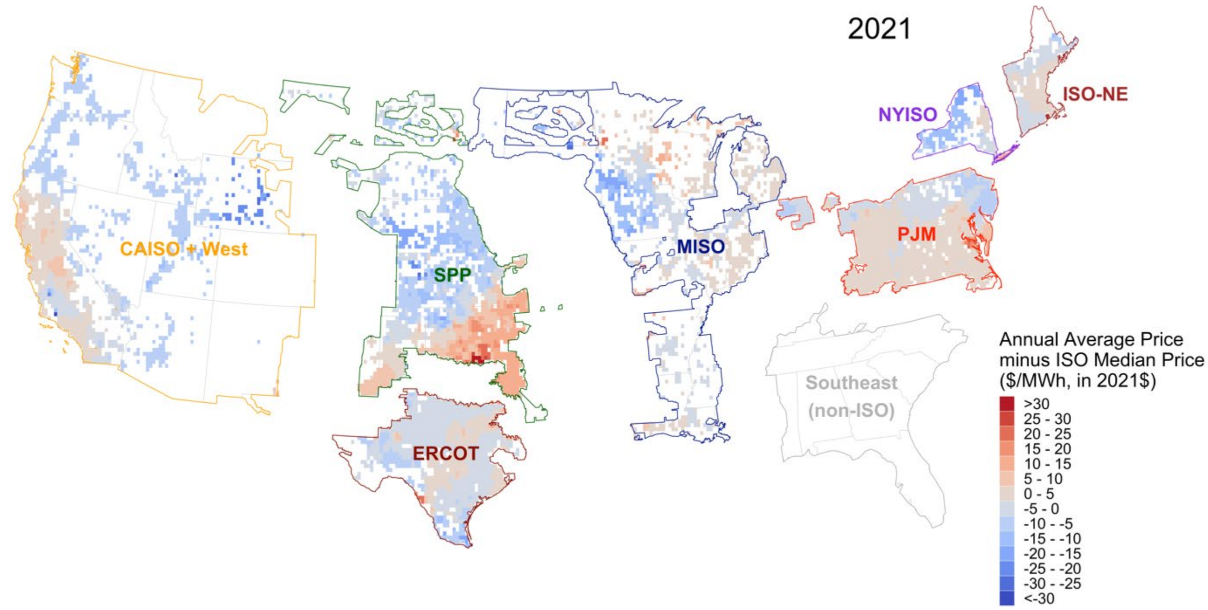
Wholesale electricity prices from the seven RTO/ISO energy markets can be used to identify regions that would benefit from additional transmission resources. Prices within these wholesale electricity markets are determined at locational marginal price nodes allowing prices to vary depending on local conditions. Nodal prices are divided into three constituent parts: energy, losses, and congestion. The energy component is constant at all nodes within a single market, but the losses and congestion components vary by location. The cost of losses is small, which means that price variation by location within each market is driven primarily by transmission system congestion.

This analysis builds on past work. FERC (2017) identified that price differentials could identify insufficient transmission between locations and DOE (2020) examined congestion in wholesale markets using RTO/ISO-reported congestion costs. These reports presented congestion costs only at the regionwide level; as a result, they do not provide insight on where congestion is most costly within each region, nor do they provide insight on the value of interregional transmission. Additionally, RTO/ISO-reported congestion metrics are challenging to compare to each other because each RTO/ISO has a different approach for calculating these metrics. DOE (2020) also examined transmission line usage rates in the western United States, finding high usage on some transmission lines. This market price analysis goes beyond past work by analyzing and identifying congestion across all nodes within each region and providing a metric to examine the value of interregional transmission. In this analysis, price differences within and across energy markets were examined to understand trends in congestion and the implications for transmission expansion. The analysis reported here as well as additional details can be found in Millstein et al. (2022a) and (2023).

Regional price differences highlight locations of persistently high electricity prices

Congestion has created gradients in electricity prices across each major wholesale market region. These spatial gradients can be observed in Figure IV-8, which shows how the 2021 annual average price at each node differs from the median annual average price across all nodes in a region. For example, prices are low in northern and high in southern Plains region (SPP), prices are low in western and higher in eastern Midwest (MISO), and prices are low in the eastern portion of the Mountain (CAISO + West) region,[33] but higher in California, especially near population centers. A north/south pricing gradient in New York (New York Independent System Operator, NYISO) and New England (New England Independent System Operator, ISO-NE) is also apparent. New transmission between these and other low- and high-priced regions would allow load in high-priced markets to draw energy from a larger set of generators and lower electricity costs in high-priced regions. The extent to which high prices could be reduced depends on the magnitude of available generation made accessible by the new transmission. Goggin (2021) explores the potential for interregional transfer during recent extreme weather events, such as the February 2021 cold weather event (frequently referred to as Winter Storm Uri). Goggin (2021) finds that while transfer across regions would have been limited by lack of available generation during certain hours, substantial transfers across existing lines did help to limit price spikes in multiple regions and additional transmission capacity would have allowed for even greater reduction to price spikes during many extreme weather events.

[33] Wholesale electricity price datasets are not readily available for the non-RTO/ISO West and can create challenges in evaluating congestion along the eastern edge of the Western Interconnection. See Section V.b. for further discussion.



Source: Lawrence Berkeley National Laboratory (Millstein et al. 2022b).

Note: Each RTO/ISO is treated as a separate region, except CAISO and the larger western region, which are treated as a single region. Nodal price analysis does not provide full geographic coverage of congestion through the non-RTO/ISO western region (particularly in New Mexico and Colorado but also in portions of other states). Similarly, the analysis provides no coverage of non-RTO/ISO regions in the Southeast. Also, note that small price differences of $0–$5/MWh may be due to losses rather transmission congestion.

Figure IV-8. Price difference between nodal average price and the regional median price in 2021.

An alternative approach to defining congested regions is to identify locations with price spikes (noticeably high or low hourly prices relative to prices across a region). Of particular interest are locations that have large price spikes across many years, which could indicate insufficient transmission infrastructure (FERC 2017), or insufficient local generation. To determine locations with consistent price spikes, we used another approach FERC developed—the Market Price Differential metric (FERC 2017). The Market Price Differential metric highlights locations with persistently low- or high-price spikes over many years.[34]

In contrast to the price gradients shown in Figure IV-8, the Market Price Differential metric shows only a subset of all nodes, which allows identification of discrete locations that would benefit from transmission. For example, Figure IV-9 shows discrete pockets of low- and high-priced nodes across the eastern region. Of particular note are the low-priced pockets centered on the Oklahoma and Kansas border in the Plains, collocated with substantial wind resources. Similarly low-priced pockets can be found near wind resources in the Midwest in Iowa and Minnesota, and in the Mid-Atlantic in Illinois. High-priced regions are identified in New York City and Long Island, in the Mid-Atlantic near Washington, DC, and in the eastern Plains region. A full list of high- and low-priced regional "pockets" is presented in Table IV-2. Additional transmission to bring cost-effective generation to demand in any of these high-priced locations

[34] More information on the methods used here and summary data are available in the Supplemental Material.

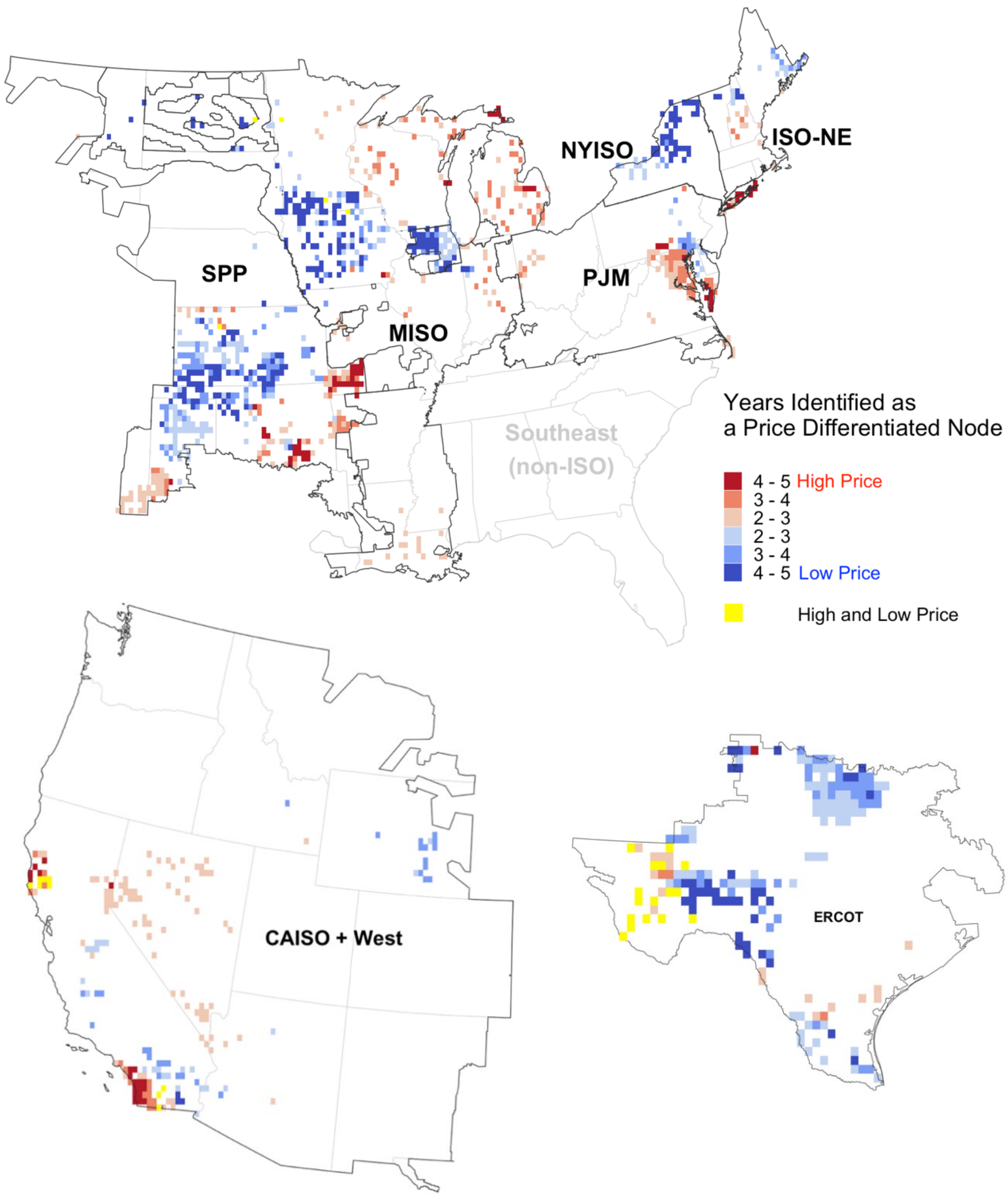
would help lower prices in those regions. Other strategies (e.g., energy efficiency or new low-cost energy supply resources) could also help lower localized high prices. The specific solutions that work for each locality might be unique to that community.

Note that Figure IV-8 combines the RTOs/ISOs in the Eastern Interconnection. Alternatively, one can calculate the Market Price Differential metric within each RTO/ISO individually. Doing so largely identifies the same set of congested nodes as the interconnection-wide calculation depicted in the figure.[35] That the pattern of congested locations does not meaningfully differ between the individual RTO/ISO analysis and the combined region analysis suggests that the extreme prices in each RTO/ISO remain extreme within the context of the entire Interconnection.

The western region has fewer congested areas identified by the Market Price Differential metric (*see* Figure IV-9) compared with the many different pockets of congestion identified across the Eastern Interconnection. For the non-RTO/ISO West (Northwest, Mountain, and Southwest), however, this observation is more a function of lack of wholesale electricity price data than a depiction of actual operating conditions. Most notable is the congestion that limits energy transfer into the populated area along the southern coast of California from the nearby inland region east of the coast. Additional congestion is observed in coastal northern California and in Wyoming. There is some additional indication of congestion in Nevada, but this is found for only 2 out of 5 years, in most cases. We note that geographic coverage of the western region is sparse for the metrics shown in Figures IV-8 and IV-9. Additional analysis of congestion in the western region is discussed in Section IV.c.

Pockets of congestion are also identified in the Electric Reliability Council of Texas (ERCOT; *see* Figure IV-9). In Texas, low-price regions are identified in the northern, western, and southern areas of the state. Few high-priced nodes are identified to be consistently high priced for more than 2 years. This indicates that the location of high-priced nodes has varied by year in Texas, while low-cost nodes have been more consistent over time.

[35] See Supplemental Material for a comparison between the calculations when each RTO/ISO is considered in isolation.



Source: Lawrence Berkeley National Laboratory (Millstein et al. 2022b).

Note: The Market Price Differential metric was calculated while treating the Eastern Interconnection as a single combined region (RTO/ISO boundaries are provided for reference). The metric is calculated independently each year; nodes are highlighted when they are identified for 2 or more years. Only a subset of nodes is identified as high- or low-priced nodes, and white space indicates either no nodes in that location or existing nodes were not identified as high- or low-priced (for reference, Figure IV-8 shows all nodes). The yellow color represents nodes that contained at least 2 years identified as high-priced and 2 years identified as low-priced.

Figure IV-9. Low- and high-priced nodes identified by the Market Price Differential metric between 2017 and 2021. Top: RTOs/ISOs within the Eastern Interconnection. Bottom left: CAISO and the WEIM. Bottom right: ERCOT.

Table IV-2. High- and low-priced areas identified within the wholesale markets of the three Interconnections. Regions are defined based on a regional concentration of nodes identified with the Market Price Differential metric.

Region	Low-Priced Areas	High-Priced Areas
Plains	Southern and Western KS OK/TX Panhandles	Southern OK Southwest MO
Midwest	Southwest and Central IA Southern MN	Northwest WI Eastern and UP MI
Mid-Atlantic	Northeast IL Southeast PA	Eastern MD/VA Delmarva Peninsula MD & DE
New York	Upstate NY	Long Island NY
New England	North VT/NH	–
California	Mojave Desert CA	Southern Coast CA Northern Coast CA
Mountain	Eastern WY	–
Texas	Northern TX Western TX Southern TX	–

Interregional price differences suggest large value in cross-interconnection transmission to alleviate harmful congestion

Although the regional calculation of the Market Price Differential metric (*see* Figure IV-9) provided some indication of the need for interregional transmission, we can more directly assess the value of transmission across regions and interconnections by determining the average hourly difference in pricing between regional hubs. One indicator of the value of new transmission is the energy arbitrage potential, that is, the difference in price between two locations.[36] Transmission provides additional value not included within this energy arbitrage value, such as providing capacity value, improving grid reliability and security, helping reduce emissions by facilitating greater deployment of wind and solar resources, and improving resilience to extreme weather and unexpected events. The energy arbitrage value is also a marginal value, meaning that as transmission capacity is added to the system, the value would decline. Nevertheless, the energy arbitrage value can be an important measure of transmission value and provides an approach for ranking the value of different potential transmission connections. It is important to note that the value indicated by energy price arbitrage is indicative of value to certain market participants, but it is different from the approach that RTOs/ISOs use to measure potential new transmission value (i.e., using forward looking models to estimate production cost savings).

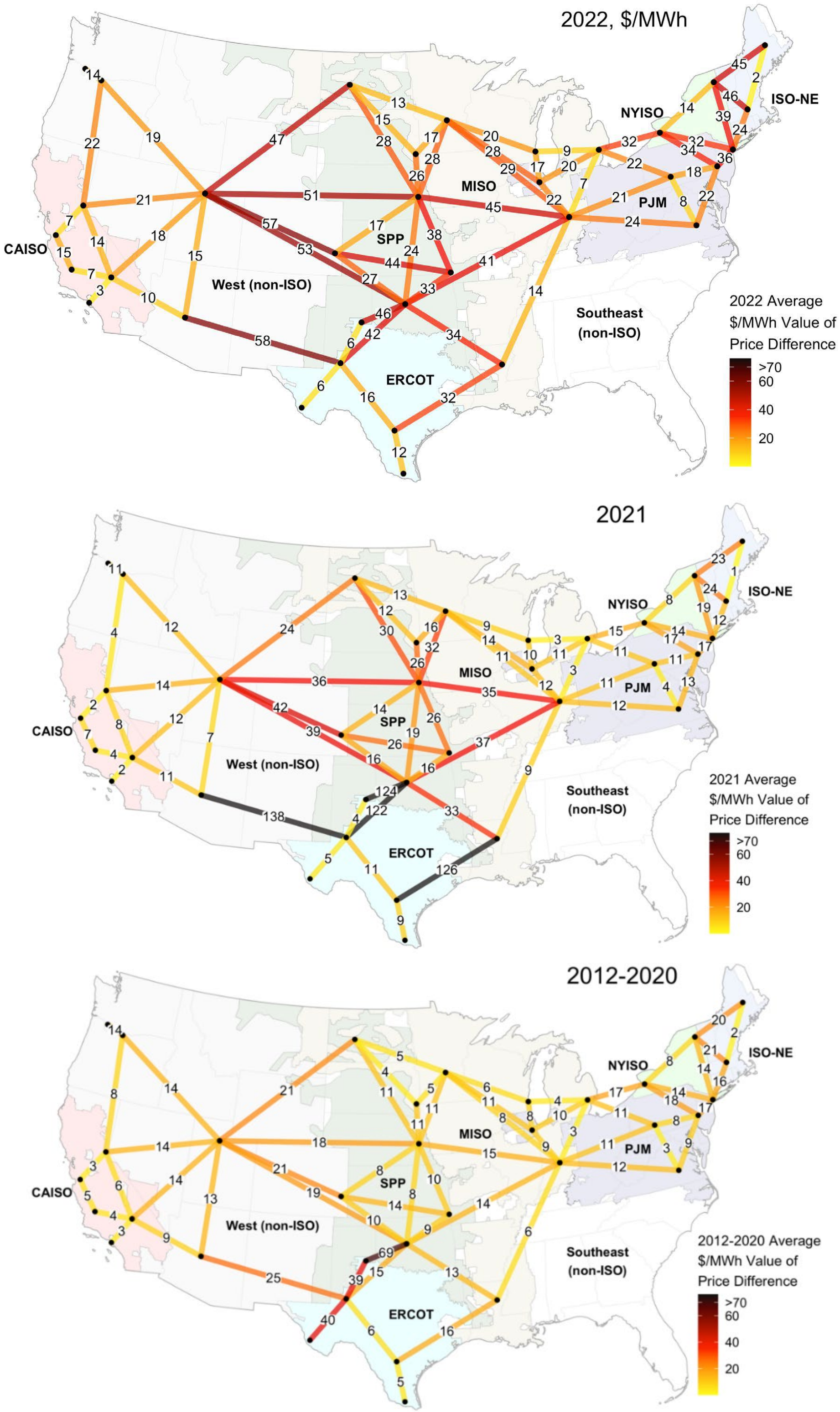
Figure IV-10 shows the average hourly difference in energy price between a selected set of pricing nodes. Selected nodes were “hub” or “zonal” nodes, as those nodes were most representative of the larger region. Specifically, these nodes represent an aggregation of regional buses and generally represent more ‘liquid’ market conditions. A high marginal value of transmission either within or between regions indicates additional, strategically placed

[36] Large hourly price differences across regions suggest transmission value but do not perfectly quantify the marginal transmission energy value between regions because market rules for nodal price formation vary by region. Thus, results here should be interpreted as suggestive, but not a definitive measure of value.

transmission would reduce system congestion and constraints. Transmission between RTOs/ISOs was generally more valuable than transmission within RTOs/ISOs. In 2022, 2021, and on average between 2012 and 2020, the highest value links were between SPP (Plains region) and its neighbors, between ERCOT (Texas region) and its neighbors, and across the northeastern regions (New England, New York, Mid-Atlantic). Exploring the time trends of these links reveals that the value of interregional transmission to SPP and to ERCOT has been increasing over time.[37]

The marginal value of transmission increased substantially in 2021 and then again in 2022 compared with prior years (e.g., compare the three panels of Figure IV-10). This increase broadly tracks the overall increase in energy prices observed since 2021. Compared with the 2012–2020 average, 2022 saw broad increases in transmission value across all regions (Millstein et al. 2023). In many locations, values in 2021 were similar to values in 2022, except for the impact of extreme weather. For example, average nodal electricity prices in Texas and the Plains were 3.9 and 1.9 times higher in 2021 than in 2019, respectively (2021 is compared with 2019 rather than 2020 to avoid comparison with the low 2020 prices caused by the COVID-19 pandemic). In other regions, 2021 electricity prices increased by 1.5 times or less between those same years (the increase was only 1.2 times in California). Thus, it is not surprising that the 2021 value of transmission between the Plains and other regions, and the value between Texas and other regions, increased by more than the increase seen between the remaining U.S. regions.

[37] Further analysis of time trends is presented in the Supplemental Material and in Millstein et al. (2022a).



Source: Lawrence Berkeley National Laboratory (Millstein et al. 2022b and 2023).

Figure IV-10. Average hourly difference in price between selected hub and zonal nodes within and across regions for 2022 (top), 2021 (middle), and for 2012–2020 (bottom).

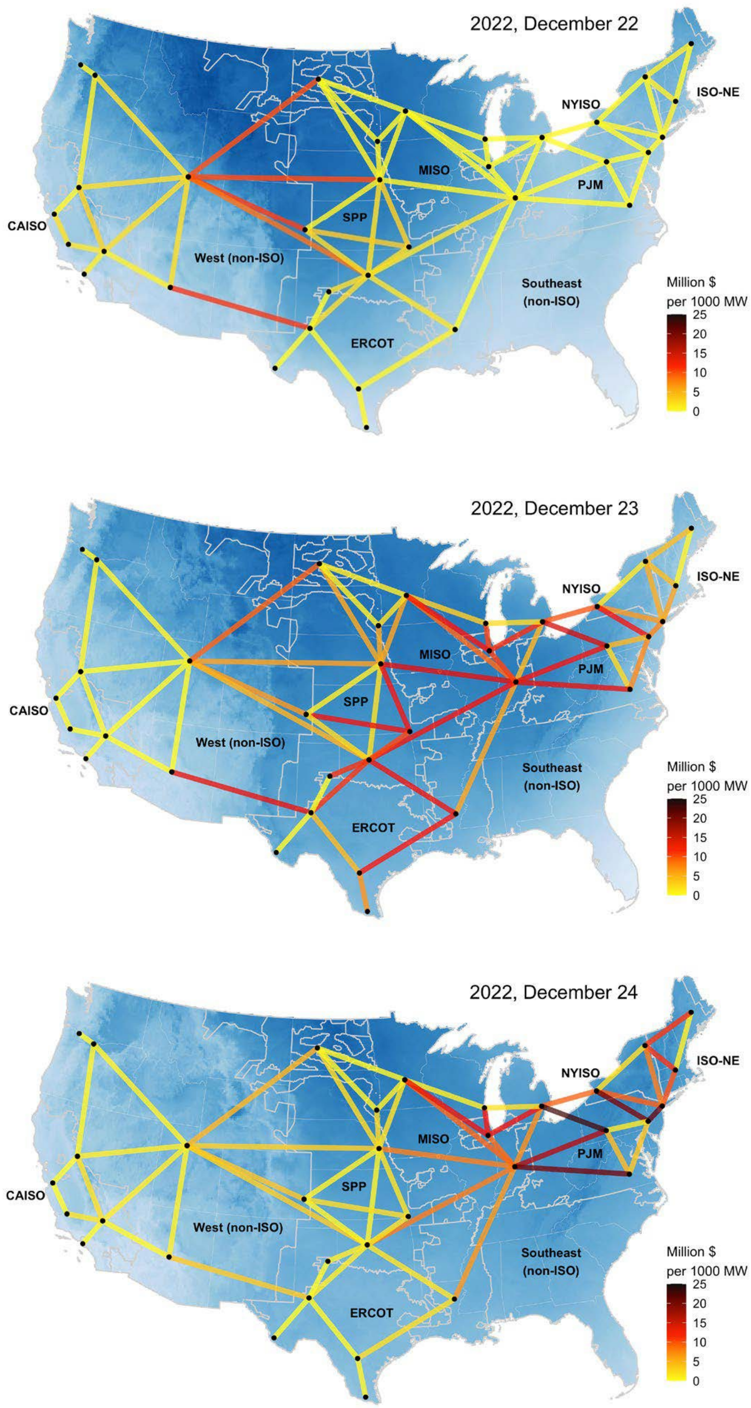
Highest transmission congestion value is concentrated in only a few hours of the year and during extreme events

Transmission value can be affected by relatively infrequent but challenging conditions on the electricity system. Examples of these conditions include fluctuations in uncertain variables for either short-term or long-term periods (e.g., fuel-price volatility, inaccurate demand forecasts, inaccurate renewable forecasts), extreme weather events (e.g., heat wave, winter storm), exceptional levels of electricity demand, and infrastructure failures (in transmission or generation equipment, for example). Correlation of the above conditions can lead to particularly high system congestion.

In the Plains and Texas, extreme weather (e.g., Winter Storm Uri) produced a price spike in February 2021 (Levin et al. 2022). This period was characterized by extremely high prices in these two regions—in the thousands of dollars per megawatt-hour (MWh)—which were not observed in neighboring regions.[38] The period of extreme prices in February 2021 was limited primarily to the Plains and Texas and demonstrates an important value of transmission: the ability to address regionally concentrated extreme weather impacts on electricity prices. The high prices found in Texas in 2021 may also have been reduced had certain regulatory changes already been implemented, including requirements for weatherization for generation resources and lower peak price limits. While 2021 reflects discrete, high-cost events in the Plains and Texas, other regions would benefit less from interregional investment in the face of similar events, which are expected to become more frequent.

Similarly high interregional transmission value resulted from Winter Storm Elliot in December 2022. Cold weather associated with the winter storm moved eastward across the country over the multiday storm, which is reflected in the daily transmission values between nodes (*see* Figure IV-11). High average hourly prices between nodes were first found between the three Interconnections on the first day of the storm, then shifted to nearly all regions in the middle of the country—Plains, Midwest, Texas, Delta, western Mid-Atlantic—on the second day, until finally impacting the northeastern regions—New England, New York, eastern Mid-Atlantic—on the third day. Additional discussion and details can be found in Millstein et al. (2023).

[38] Wholesale price patterns can be investigated with the Renewables and Wholesale Electricity Prices tool, see Millstein et al. (2022b).



Source: Lawrence Berkeley National Laboratory (Millstein, et al. 2023).

Note: Transmission value is measured in cumulative daily million USD of a hypothetical 1000 MW transmission link between two nodes. Darker blue background colors reflect colder surface temperatures.

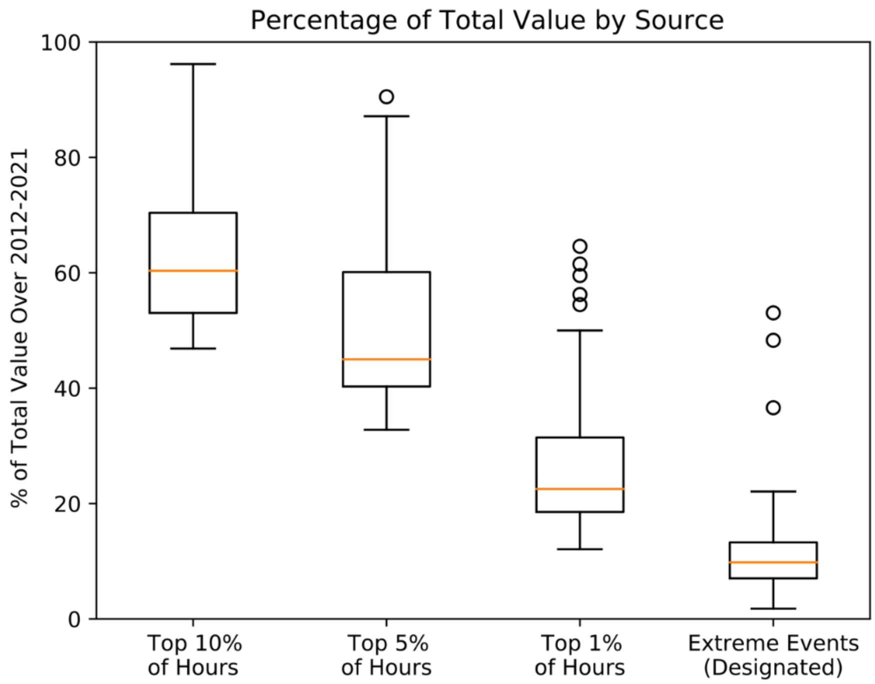
Figure IV-11. Transmission value between selected regional nodes moved east with cold surface temperatures during December 22–24, 2022 (Winter Storm Elliot).

In addition to scrutinizing price patterns during specific events, the portion of total transmission congestion value attributable to high-value hours or extreme conditions is analyzed here. Two approaches are used to identify extreme conditions or high-value hours: In the first approach, literature and NERC reports are used to identify specific time periods of grid stress and extreme weather events.[39] Congestion value over these types of events is tabulated and together the events are referred to as "designated events." In the second approach, the value at each potential transmission link is calculated each hour and ranked, and the portion of total value contained in the top 1%, 5%, and 10% of hours (sorted by value) is tabulated. This second approach assumes that, although there was not necessarily a named weather event or infrastructure outage during all these top hours, the very fact that the price differential is so high indicates that an infrequent set of conditions exists. These conditions may not require emergency action by the RTO/ISO, and in fact may be an infrequent condition that occurs during standard operational conditions but occur during a period in which the market faces extreme price differences. The first and second approaches identify a somewhat overlapping set of hours, but the subsequent analysis is designed to prevent any double counting issues where relevant.

For each transmission link as established in Figure IV-10, the total value over the study period was calculated, along with the value of the top 10%, 5%, and 1% of hours (in which these hours have been determined separately for each link). An important finding here is that a small portion of hours accounts for roughly half the value. Specifically, in the median case, the top 5% of hours account for ~50% of value (*see* Figure IV-12). The top 1% of hours account for 20% to 30% of total value. Designated extreme events produce 10% to 20% of value (and account for ~5% of total hours). This indicates that many of the most valuable hours for transmission fall outside the set of designated extreme events, and instead occur during more standard operational conditions that were not flagged in the process used to designate extreme events.

Overall, this analysis highlights the importance of properly representing challenging grid conditions, including explicitly representing extreme weather events, fuel-price volatility, generation and load uncertainty, and geographic market resolution, when estimating or modeling the congestion value of transmission. Doing so is critical to ensuring that the value of transmission investments in alleviating congestion and constraints that are negatively impacting consumers is accurately accounted for in planning. Failing to account for these grid conditions, or using an inaccurate snapshot of time to determine the value of transmission, will result in transmission plans that do not address the negative impacts of congestion and constraints over time. Additional discussion and details can be found in Millstein et al. (2022a).

[39] Details can be found in (Millstein et al. 2022a).



Source: Lawrence Berkeley National Laboratory (Millstein et al. 2022a).

Note: The distribution reflects the spread across the set of links shown in Figure IV-10. Designated "extreme events" include 171 event days between 2012 and 2021 defined in Millstein et al. (2022a)

Figure IV-12. The portion of transmission congestion value derived from selected conditions over 2012–2022.

IV.c. Qualified Paths

For the non-RTO/ISO Western Interconnection, evaluating congestion can be a challenge because of a lack of wholesale electricity price data. Instead, information on congestion management, particularly along the eastern edge of the Western Interconnection, can be obtained from transmission system operators and The Western Electricity Coordinating Council (WECC).

When congestion occurs along the West Coast, which can be frequent as demonstrated by the Market Price Differential analyses in Section IV.b., 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 (*see* Figure IV-13). In response, the Western Interconnection uses the WIUFMP. The WIUFMP is a FERC-filed tariff that provides a mechanism for reliability entities to mitigate flows on Qualified Paths to reliable levels.[40]

Qualified Paths in the West designate transmission with the highest levels of congestion. Four of the approximately 50 paths in the Western Interconnection were identified as qualified

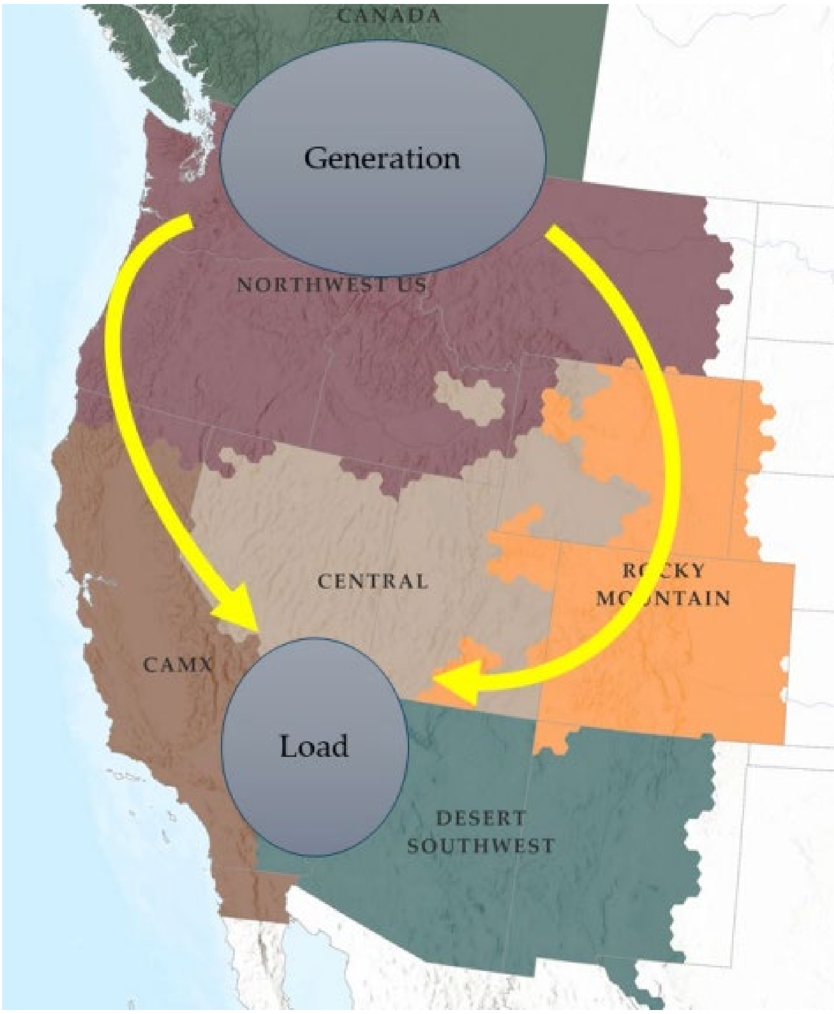
[40] The WIUFMP FERC tariff is available at https://spp.org/documents/62460/081919%20wiufmp%20tariff.pdf.

paths. Path 66 (California), Path 36 (Wyoming-Colorado), Path 30 (Colorado-Utah), and Path 31 (Southern Colorado-Northern New Mexico) are bottlenecks of limited transmission to deliver power from the Northwest to the highly populated Desert Southwest (SPP 2020). These paths are listed in Table IV-3. Figure IV-14 shows these paths and many major paths in the Western Interconnection.[41] The parallel nature of the Qualified Paths creates simultaneous interactions between the eastern and western portions of the Western Interconnection that can create reliability risks. Additional, strategically placed transmission deployment would alleviate unscheduled flows on Qualified Paths. Historically, the West has leveraged specific phase-shifting transformers, also referred to as Qualified Controllable Devices, to redirect flows to manage unscheduled flow.

Phase shifters were a cost-effective alternative to additional transmission for many years, but their effectiveness is decreasing as the industry transitions away from tradition thermal generators to renewable energy resources. Much of the existing high-voltage transmission system was constructed around thermal generators. Utility-scale renewable resources are in different locations relative to existing transmission infrastructure, which has implications for transmission loading and can create incremental unscheduled flows on certain transmission segments, including the qualified paths.

In addition to the phase shifters, thermal generators have traditionally been leveraged as tools to manage congestion. Generator output can be increased or decreased on either side of affected transmission segments, which can aid in alleviating constraints. Given the number of thermal generator retirements, incrementing and decrementing generation is not as available as a tool for congestion management. This lack of availability increases the reliance on the phase shifters, which were not designed to manage the changes in transmission flows developing on the system.

[41] Stakeholders have also independently assessed congestion on other major paths within the Western Interconnection. CAISO, for example, has conducted a high-level investigation of major transmission congestions as part of its 2022-2023 Transmission Plan and has identified various additional WECC paths as constrained areas. *See* CAISO at https://www.caiso.com/Documents/ISO-Board-Approved-2022-2023-Transmission-Plan.pdf.



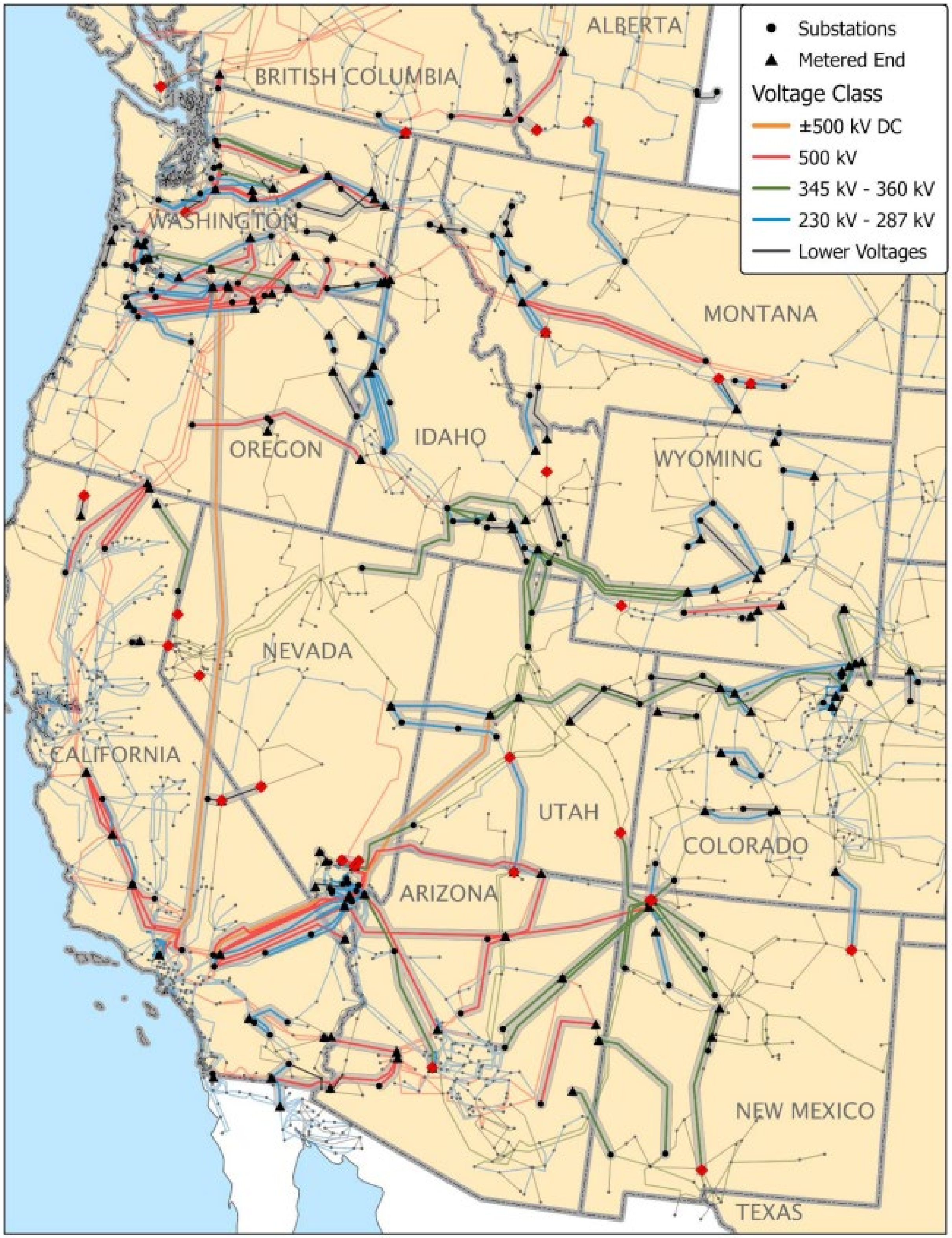
Source: Western Electricity Coordinating Council (March 2021); https://www.wecc.org/Reliability/August%202020%20Heatwave%20Event%20Report.pdf.

Figure IV-13. Loop flow in the Western Interconnection.

Table IV-3. Qualified paths and path operators in the Western Interconnection.

Qualified Path	Path Location	Path Operator
Path 66 – California Oregon Interface (COI)	Southern Oregon, Northeast California, and Northwest Nevada border	CAISO
Path 30 – TOT1A	Northeast Nevada and Northwest Colorado border	Western Area Power Administration (WAPA)
Path 31 – TOT2A	Southern Colorado and Northern New Mexico border near Four Corners	WAPA
Path 36 – TOT3	Southeast Wyoming and Northern Colorado border, north of Denver	WAPA

Source: Qualified Paths and path operators in the Western Interconnection from SPP at https://spp.org/documents/58826/current%20list%20of%20qualified%20devices%20&%20paths_062520.pdf.



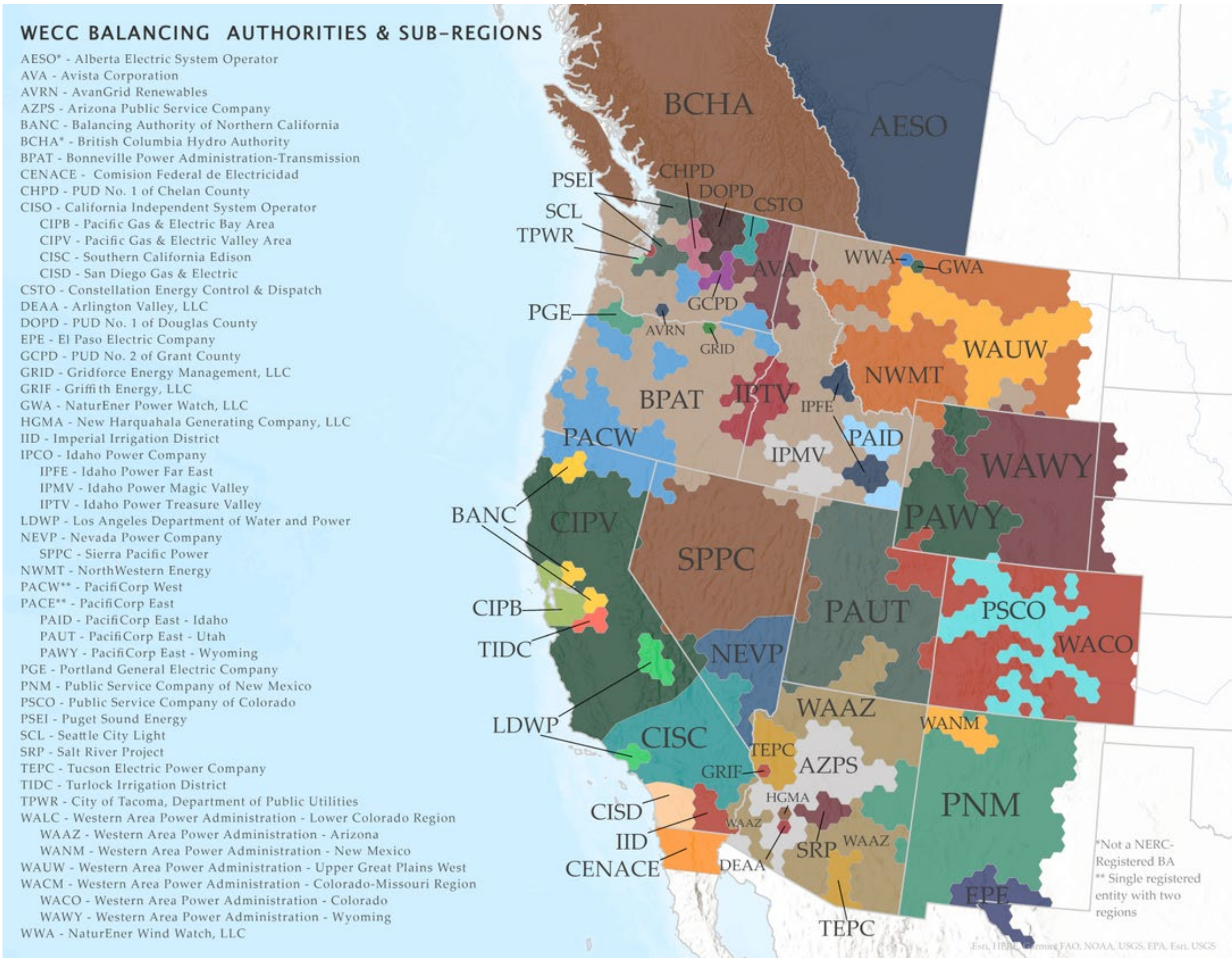
Source: Western Electricity Coordinating Council; https://www.wecc.org/Reliability/2023%20Path%20Rating%20Catalog%20Public.pdf.

Figure IV-14. Paths in the Western Interconnection.

Additional transmission and expanded market structures to price and manage congestion are potential solutions to congestion challenges in the non-RTO/ISO West. The need for additional transmission capacity will become increasingly acute as transmission flow patterns continue to change because of additions of variable energy resources (VERs), thermal generator retirements, and drought-induced reductions in hydropower generation. Of critical importance is that changes made to the transmission system on the western edge of the Western Interconnection (CA, OR, WA) can have significant implications for transmission system operations on the eastern edge of the Western Interconnection (WY, CO, NM) because of the unscheduled loop flow described previously. This reliability and economic consideration is system wide. As the transmission system is expanded along the West Coast, transmission upgrades also might be necessary along the eastern edge of the Western Interconnection to protect system reliability across the entire West. Interconnection-wide power flow analyses and system impact studies will be essential in the study processes.

The non-RTO/ISO West faces unique challenges because it currently consists of 38 separate balancing authority (BA) areas as shown in Figure IV-15. 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 system known as Security Constrained Economic Dispatch to automatically adjust generation outputs in response to real-time system congestion, a base functionality not used by the BAs. The manual processes used in the non-RTO/ISO West to adjust generation were reasonably effective when net load (demand less variable generation) was straightforward to forecast. The fragmented BA model, however, is becoming increasingly difficult to manage. Automated economic dispatch procedures provided through CAISO's WEIM have partially addressed the difficulties in managing manual coordination between generators and transmission operators for WEIM participants in the Western Interconnection.

Another factor associated with the non-RTO/ISO West is that interregional transmission is exceptionally difficult to plan or develop because of a lack of centralized planning processes and codified cost allocation mechanisms. As a result, the transmission development that does occur is not optimized from a regional reliability or economic perspective.



Source: Western Electricity Coordinating Council Maps of the Western Interconnection; [*https://www.wecc.org/ReliabilityModeling/Pages/Maps.aspx*](https://www.wecc.org/ReliabilityModeling/Pages/Maps.aspx)

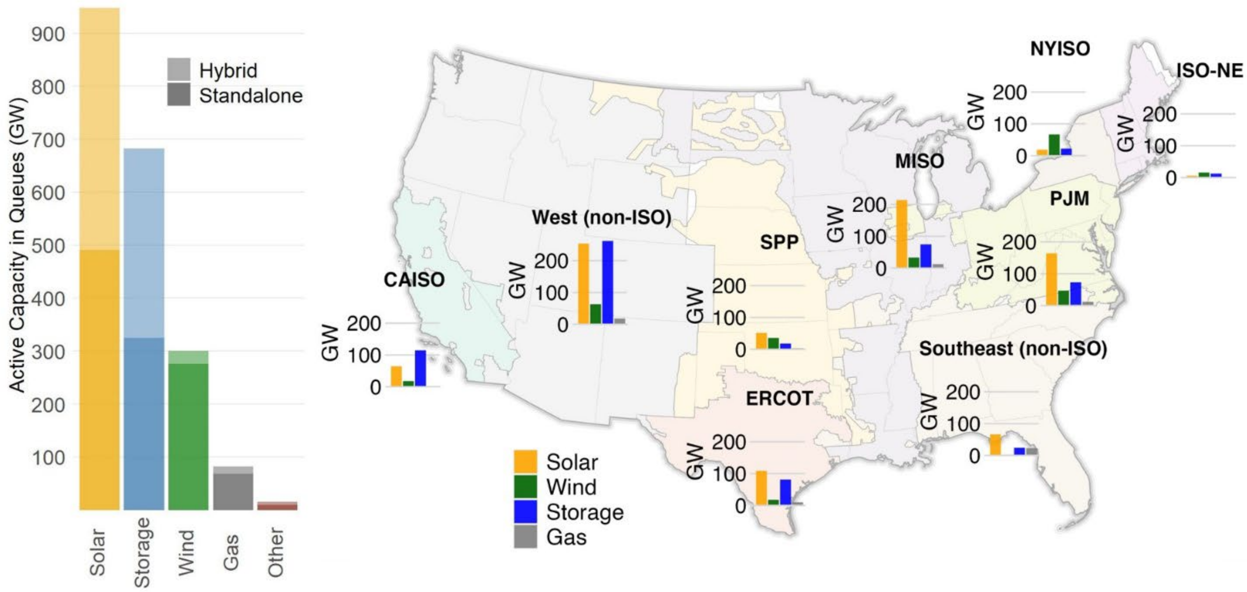
Note: Boundaries are approximate and for illustrative purposes only.

Figure IV-15. Western Electricity Coordinating Council balancing authorities.

IV.d. Interconnection Queues

All generation requests must undergo a series of studies before connecting to the transmission system to ensure grid reliability will not be negatively impacted. Generators wait in line for these studies in interconnection queues. Data from generation interconnection queues also demonstrate the growing need for new transmission infrastructure.

The latest compilation of data from Lawrence Berkeley National Laboratory shows that a record amount of new generation and storage capacity has applied for interconnection (DOE 2022a; Rand et al. 2023). More than 2,000 Gigawatts (GW) was sitting in clogged interconnection queues at the end of 2022, the majority of which was solar and storage, but also included large amounts of wind and gas facilities (*see* Figure IV-16). The enormous amount of solar, wind, and storage in the interconnection queues demonstrates that market and economic trends will lead to continued shifts in the Nation's resource mix, requiring a different approach to transmission planning and development. As discussed later (Section VI), studies have repeatedly shown that given the Nation's changing resource mix, a least-cost power grid requires enhanced transmission links within and among regions.



Source: Data from Lawrence Berkeley National Laboratory; https://emp.lbl.gov/queues.

Note: Hybrid plants are those paired with one or more other type of generation or storage.

Figure IV-16. Power plants seeking transmission connection by type (left) and mapped to region (right).

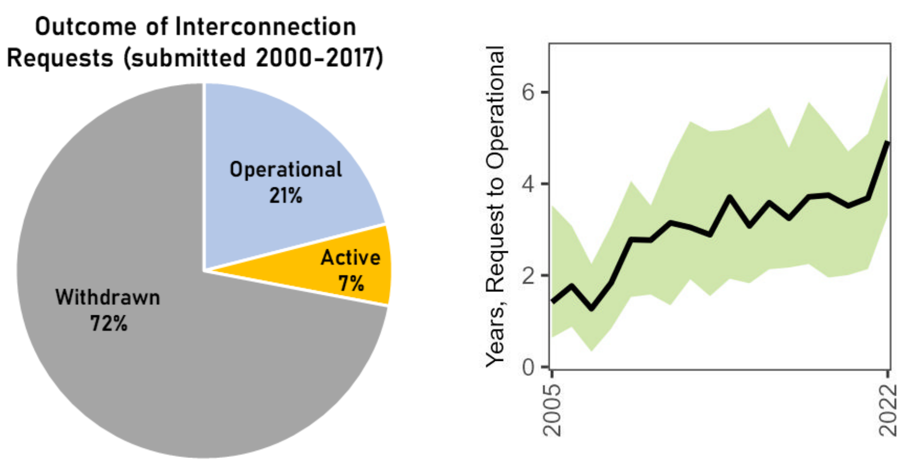
Generation is waiting longer to connect to the transmission system

The duration between an interconnection request and commercial operation has increased. Among the regions with available data, the typical duration from an interconnection request to commercial operation was 5 years in 2022, compared with 3 years in 2015 and less than 2 years in 2008 (*see* Figure IV-17). The average duration from a request to a signed agreement has also increased in most regions and, on average, nationally for those regions where such data are available. High withdrawal rates are also evident: 72% of projects that sought interconnection between 2000 and 2017 subsequently withdrew their requests.

There are numerous drivers of these trends. While lack of access to transmission is a major barrier, there are many potential reasons that proposed power plants do not always move rapidly to the construction phase. Some projects in the queues are speculative in nature, in part driven by uncertainty in the scope and cost of necessary transmission upgrades and the extended timelines associated with the current interconnection process—often leading prospective projects to submit an interconnection to obtain information, followed by withdrawals and successive restudies of other projects. Other challenges include securing land, permits, community support, power purchasers and financing, as well as unanticipated changes to project economics and available policy incentives. In addition, some projects enter and remain in the queues because of the lack of disincentive for doing so.

As such, these trends partly reflect strong growth in interconnection requests and a diversity of underlying project-level and queue management issues. Yet there is also recognition that trends in interconnection queues are impacted by limited existing transmission infrastructure and resulting transmission upgrade costs needed for interconnection that, in many cases, the interconnecting generator must bear (DOE 2022a). Specifically, developers often incur costs not only to connect to the existing transmission system but must also provide up-front capital costs needed to upgrade the broader, high-voltage transmission grid, which provides benefits to those behind them in the queue and to the users of the networked transmission system more generally. Interconnection costs are increasing, especially for these broader network upgrades (Caspary et al. 2021; Gorman et al. 2019). The specifics of cost allocation for these network upgrades vary regionally, but evidence is mounting that some of these network upgrades paid by interconnecting generators provide system-wide benefits (ICF 2021). Assigning the costs of these broader network upgrades to the first generator in line can cause those projects to drop out, even though those upgrades could facilitate additional interconnecting generators further down the queue.

As described in a recent FERC Notice of Proposed Rulemaking (FERC 2022), these challenges are partly related to an increasing portion of overall transmission investment occurring through these interconnection agreement processes, which could result in less cost-effective transmission deployment. FERC suggests the piecemeal approach to transmission deployment occurring with the interconnection agreement process will not benefit from the economies of scale that would accompany a full regional transmission planning process. FERC notes that improved transmission planning and additional investment in the bulk power transmission network will be needed to optimize the overall power grid and would be an effective means to address the increasingly long interconnect queue times (FERC 2022).

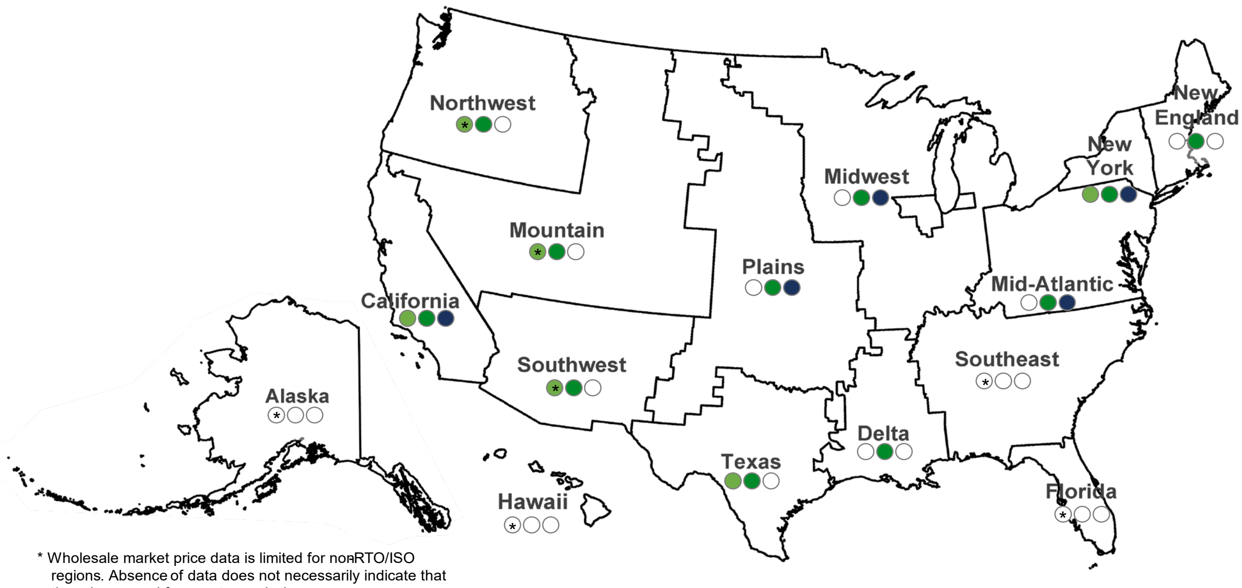


Source: Data from Lawrence Berkeley National Laboratory; https://emp.lbl.gov/queues.

Figure IV-17. Indicators of the challenges facing transmission interconnection, planning, and construction. Right panel shows the median (black line) and interquartile range (green envelope) of years from generator interconnection request to operation for projects dating back to 2005.

IV.e. Conclusions

Figure IV-18 summarizes findings of current transmission needs by geographic region as determined by the data and studies referenced in the Section IV discussion of historical market conditions. The different color circles located on the map of Figure IV-18 (top) correspond to the transmission needs listed in the dashboard (bottom).



* Wholesale market price data is limited for non-RTO/ISO regions. Absence of data does not necessarily indicate that there is no need for new transmission.

Region

Current Need	California	Northwest	Mountain	Southwest	Texas	Plains	Midwest	Delta	Southeast	Florida	Mid-Atlantic	New York	New England	Alaska	Hawaii
Alleviate congestion & unscheduled flows	●	●*	●*	●*	●				*	*		●		*	*
Alleviate transfer capacity limits between neighbors	●	●	●	●	●	●	●	●			●	●	●		
Deliver cost-effective generation to meet demand	●					●	●				●	●			

Source: See Supplemental Material for supporting references and methodology.

Figure IV-18. Summary of current transmission needs identified in Section IV by geographic region.

A review of historical transmission system data from 2011 to 2020 provides information about the state of the grid today. Regional differences in transmission capital expenditures ranged between $0.17 and $5.90 per MWh of regional annual load, on average over the last decade. These investments resulted in a national total of 33,000 circuit-miles of newly constructed or rebuilt transmission lines rated above 100 kV. Of these, 20,000 circuit-miles were higher capacity lines rated at least at 345 kV. Most of these investments were made in the first half of the decade, with transmission investments steadily declining since 2015.

Wholesale market prices in the RTOs/ISOs provides insight into where transmission congestion currently exists. Several regions of the country have had either consistently high or consistently low electricity prices over the past 3–5 years. Increased transmission access to persistently high-priced regions provides one way to lower prices for those consumers. Regions of high prices exist in Southwest MO, Southern OK, Northwest WI, Eastern and UP MI, Eastern MD/VA, Delmarva Peninsula MD and DE, Long Island NY, Southern Coast CA, and Northern Coast CA. These regional and interregional transmission links have significant potential economic value from reducing congestion and expanding opportunities for trade. Extreme conditions and high-value periods play an outsized role in this value of transmission, with 50% of transmission's congestion value coming from only 5% of hours.

Examining differences in simultaneous market prices across the United States provides additional insight into the value of transmission during real-time operations. The greatest transmission value is found by connecting regions in the middle of the country with their more eastern or western neighbors, particularly by connecting the three transmission interconnections. The highest value is found by connecting Texas to the Southwest region of the Western Interconnection, followed by connecting Texas with Plains and Delta regions in the Eastern Interconnection. There is also significant value in connecting the Plains with the Mountain region of the Western Interconnection and with Midwest and Delta regions to the east. The value of these interregional connections has been growing over the past 5 years of data considered. Identifying the best nodal locations to make these connections requires additional engineering analysis that considers downstream system upgrades to support increased energy transfers.

In the non-RTO/ISO West, heavy traffic of energy moving from the Northwest into load centers in California and the Southwest causes congestion. As of the publication of this report, the most congested paths are between Oregon and California and between Colorado and its three neighbors in the Western Interconnection, Wyoming, Utah, and New Mexico. This congestion results in reliability concerns for the entire western system, particularly as the generation fleet is replaced because of age, climatic changes (e.g., severe drought conditions), and advancing technologies. Additional transmission is one solution to addressing these concerns.

A review of the power plants currently awaiting interconnection agreements in different parts of the country suggests the generation mix will continue to shift toward more wind, solar, and battery storage technologies. The length of time from interconnection request to operation for all generation and storage resources has grown from less than 2 years in 2008 to more than 5 years in 2022. Generation resources with strong technical and economic potential located far from the existing transmission system—notably wind energy—require building new transmission to bring these low-cost resources to load (Brooks 2022). Storage technologies can help fortify the transmission system, helping ensure that the transmission built will be more highly utilized, as discussed in Section V.d.

V. Current and Future Need Assessment and Identification of Transmission Benefits through Review of Existing Studies

This literature review surveys more than 120 recent reports to highlight the historical and anticipated drivers of transmission needs, the multiple benefits that additional transmission infrastructure can provide to consumers, and the challenges of expanding the Nation's electric transmission infrastructure. The literature includes reports from the U.S. Government, national laboratories, academia, consultants, and a cross section of industry participants that incorporate quantitative and qualitative measures of electricity transmission needs. Reports were chosen on the basis of geographic diversity, diversity among sources, and author subject matter expertise, and to cover a range of critical reliability and congestion issues faced by the transmission system today.[42] Similar to historic data analysis, regions that lack public reporting on the power system may be underrepresented here.

The reports considered as part of this literature review explore the historical and anticipated drivers of transmission, including reliability, resilience, curtailment, congestion, resource adequacy, interconnection of generation sources, and evolving demand trends. As discussed throughout the reports, upgraded and expanded transmission can provide an array of system resilience, reliability, and economic benefits in addition to facilitating access to clean sources of energy.

Additionally, various reports discuss opportunities to advance energy justice goals through the identification and mitigation of potential impacts to disadvantaged communities during transmission planning and development processes, as well as the importance of early and meaningful engagement with potentially impacted communities. Reports included in this literature review also consider the potential for deployment of alternative transmission solutions, such as GETs and other alternative transmission solutions, which reduce potential land use impacts while increasing energy access and supporting system reliability and resilience.

Recent literature identifies the challenges of meeting transmission needs, notably the fragmented approach to permitting and siting, complex planning, land use considerations, the need for improved quantification of benefits in cost allocation, and various other barriers.

V.a. Reliability and Resilience

The recent literature reviewed for this Needs Study demonstrates that transmission infrastructure plays an important role in maintaining grid reliability, bolstering grid resilience, and addressing VER integration needs and emerging resource adequacy concerns.

FERC (2020) reports that high-voltage transmission can improve the reliability and resilience of the transmission system by enabling utilities to share generating resources, enhancing the

[42] A full list of studies, publishers, and funding sources can be found in the Supplemental Material.

stability of the existing transmission system, aiding with restoration and recovery after an event, and improving frequency response and ancillary services. Following disruptive events, high-voltage transmission lines can help with restoration and recovery by serving power from black start units once enough generation is operational. Additionally, high-voltage transmission lines help maintain a consistent frequency and enhance the stability of interconnected transmission by dampening interarea disturbances.

Addressing specific incremental grid reliability needs is a major driver of local transmission need, as cited in Brinkman et al. (2021), Clack et al. (2020b), and NERC (2021). As the power system continues to evolve, reliability is anticipated to remain a key driver of new transmission overall. NERC (2021), for example, finds reliability to be the dominant driver for planned transmission projects, noting that 64% of future circuit-miles of transmission are anticipated to be installed for reliability purposes. MISO (2022a) notes that the transformational changes occurring in the industry necessitate the identification of transmission solutions to ensure continued grid reliability and cost-effective transmission investments that will serve future needs.

A resilient transmission system can withstand many simultaneous maintenance-based or forced outages during even moderate electricity demand conditions. This resilience is especially important as scheduling outages becomes more difficult with an aging transmission system. The number of transmission facilities and associated components in need of maintenance often exceed a utility's ability to service them in a timely manner. This backlog of maintenance requests leads transmission owners to develop risk-based asset management techniques to prioritize the most critical assets (BPA 2022). While new transmission facilities can serve to improve system resilience, Pfeifenberger (2021) finds that recent efforts to replace aging transmission infrastructure create an opportunity to build a more robust, reliable grid, while efficiently using existing rights-of-way.

Further, transmission expansion can help to ensure grid reliability standards are met by increasing grid flexibility. Brinkman et al. (2021) and Brown and Botterud (2020) state that transmission—particularly interregional transmission—can increase grid operational flexibility. Ardani et al. (2021) similarly claim that transmission expansion is required to make the grid more flexible. Pfeifenberger (2021) claims that a more flexible and robust grid will reduce the risk of high-cost outcomes (both short and long term) that are due to inadequate transmission.

The ability of transmission expansion to support system reliability and resilience also extends to offshore systems. Pfeifenberger et al. (2020b) state that an offshore grid designed and built with the capability of a networked system will improve reliability and reduce curtailments when transmission outages occur.

Outside of the contiguous United States, Alaska and Hawaii's power systems have been found to need additional transmission capacity to support system reliability and resilience. Alaska's Railbelt region is composed of a roughly 700-mile transmission network stretching from Fairbanks through Anchorage and to the Kenai Peninsula, serving approximately 75% of the state's electric load. Within the Railbelt, a lack of system redundancy can create significant challenges during transmission outages. The Alaska Energy Authority (AEA) finds that the deployment of additional transmission paths parallel to constrained single lines, particularly near the interties and certain areas of the southcentral Railbelt region, can help reduce the need for load shedding following contingency events (AEA and EPS 2017).

Transmission systems on Hawaiian Islands, such as Kaua'i, would also benefit from additional transmission capacity during contingency scenarios. Kaua'i Island Utility Cooperative (KIUC) describes that its system is capable of riding through a single contingency in accordance with its system voltage and frequency requirements with current generation and load levels (KIUC 2022). However, with anticipated load growth, additional transmission infrastructure would allow for a more resilient grid in the face of plausible contingency scenarios (KIUC 2022).

Transmission can support a reliable grid with high penetrations of variable energy resource generation

VERs—such as wind and solar energy—are intermittent in nature and difficult to forecast at the temporal resolution (on the order of seconds) necessary for reliable operations. The rapid growth in the use of VERs poses unique grid reliability concerns that must be mitigated. Despite these reliability concerns, various study findings demonstrate transmission can serve to accommodate increased VER integration and increase system reliability in response to future changes in the generation mix.

NERC (2021) highlights that increased use of electrical inverters—which are required to connect batteries and many renewable energy resources to the grid—can lead to reliability concerns unless precautions are taken. System reliability concerns may arise from low inertia, unstable voltage, low fault currents, and unpredictable behavior of inverter-based resources during grid disturbances without appropriate precautions. In 2021, both Texas and California experienced the loss of widespread solar photovoltaic generation due to abnormal operation of inverters (NERC 2022a). Transmission planning, reliability studies, interconnection requirements, and operational control of the transmission system are crucial to account for the unique behavior of inverters on the grid (NERC 2021; NERC 2022a).

Novacheck et al. (2021) find that the operational and resource adequacy issues caused by historical high-impact weather events, such as the 2014 "polar vortex" that impacted the Midwest and the northeastern United States, have not been further exacerbated by a higher penetration of VERs on the electricity system. They do find, however, that milder versions of these weather events have resulted in concerns during prolonged periods of low VER availability. The authors note that expanding transmission to access geographically diverse energy resources—both firm and variable—can reduce these risks, suggesting that transmission can increase grid reliability in the face of risks posed by future weather events.

Similarly, ISO-NE finds in its *Future Grid Reliability Scenarios* study that even in a mild weather year—such as the 2019 weather year used in the study—weather events may pose significant challenges to maintaining electrical grid reliability in New England under a high VER future (ISO-NE 2022a). The study's reliability analyses show whether the simulation-produced generation mixes have either excess or insufficient capacity to serve load. ISO-NE finds that resource adequacy analysis overestimates the reliability of renewable resources during the hours of highest risk, suggesting more nuanced modeling of renewable resources is required to fully assess reliability under a scenario with high penetration of VERs. While ISO-NE finds fixed output values used in the resource adequacy analysis for solar and wind are sufficient for the current New England system and resource mix, that assumption is no longer adequate in high VER penetration scenarios where widespread wind lulls and cloudy weather become more impactful (ISO-NE 2022a).

Clack et al. (2020b) model wind and solar resource development within the Eastern Interconnection and find that investing in transmission can help accommodate low-cost renewable energy integration without compromising system reliability. Clack et al. (2020b) determine that a strong transmission network can allow the bulk power system to be able to operate reliably in high VER penetration scenarios where wind and solar supply up to 82% of electricity by 2050.

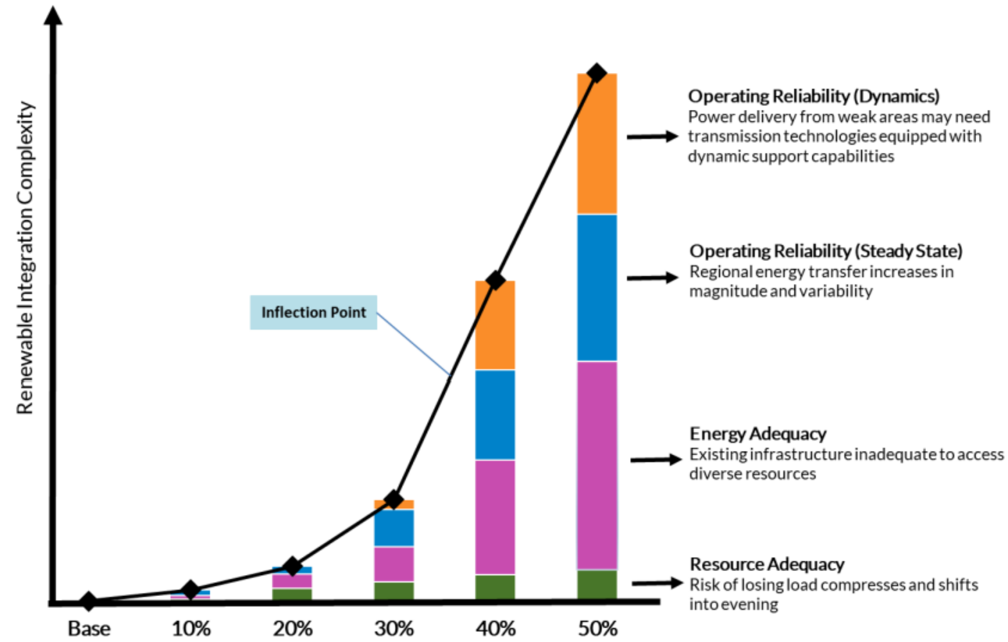
Prabhakar et al. (2021) describe MISO's *Renewable Integration Impact Assessment*, which examines the potential impacts and solutions for increased wind and solar installation within the Midwest and Delta regions. Prabhakar et al. (2021) conclude that the effort required to develop and operate new resources reliably as they are integrated with the grid substantially increases at renewable penetration levels beyond 30% of annual load served, as shown in Figure V-1.

MISO's LRTP initiative (MISO 2022a; MISO 2022b) also references its *Renewable Integration Impact Assessment* study and assesses reliability risks looking 10–20 years into the future to identify the transmission investments needed to enable regional delivery of energy. The LRTP process creates a portfolio of Midwest regional transmission solutions planned to address future energy needs and provide multiple benefits to consumers in the region, rather than using a project-by-project single benefit approach to reliability planning. LRTP projects are expected to deliver benefits by addressing future reliability issues and avoiding the costs of future upgrades that would have been required absent the portfolio (MISO 2022a; MISO 2022b).

Transmission can mitigate impacts of extreme weather events

Extreme weather events can impact all aspects of the power sector, including generation, transmission, and distribution. This section focuses on the role of transmission in maintaining system reliability and resilience during extreme events.

Novacheck et al. (2021) demonstrate how transmission can support system resilience during certain weather events. The authors explain that risks posed by regional icing and cold temperature shutdowns, although rare, can be mitigated by local gas generation dispatch and interregional transmission, either individually or in concert. Goggin (2021) similarly investigates the value additional transmission would have provided to the power grid during recent severe weather events. The study finds that an additional 1 GW transmission tie to the Southeast during the Texas heat wave of 2019 could have saved Texas consumers nearly $75 million.



Source: Midcontinent Independent System Operator (MISO 2021).

Figure V-1. Additional operational effort (e.g., additional cost) is needed to maintain system reliability as renewable generation levels (x-axis) increase. The MISO transmission system maintains reliability up to 30% renewable energy generation without significant additional operational support.

As discussed by NERC (2021), regions such as California, Texas, and the Northwest, where regional operators tend to rely on VERs and imports to meet demand during peak or high-risk periods, face higher risk of load curtailment during extreme conditions. NERC finds that regional grids in the Midwest, Delta, and Southwest regions are approaching similar conditions in the near term. NERC suggests adopting policies that promote the hardening of electric generation, transmission facilities, and fuel supplies to reduce risks to electricity reliability from extreme winter weather events (NERC 2021).

During the February 2021 winter storm event—often referred to as Winter Storm Uri—extreme cold temperatures and freezing precipitation across Texas and the southern Plains and Delta regions led to outages, derates, or failures at 1,045 individual generation units, resulting in a severe capacity shortage (FERC et al. 2021; NERC 2022a). For at least two consecutive days, ERCOT averaged approximately 34,000 MW of unavailable generation, including planned and unplanned outages. ERCOT estimates that peak generation outages and derates during the event totaled 52,000 MW, or 48% of total ERCOT installed generation capacity (ERCOT 2021c). At its peak, ERCOT shed 20,000 MW of firm load to make up for the generation shortfall (FERC et al. 2021; NERC 2022a). Goggin (2021) finds that each additional 1 GW of transmission ties between the Texas power grid and the Southeast region could have saved nearly $1 billion during the multiday winter storm, while keeping the heat on for hundreds of thousands of Texans. With stronger transmission ties, both the Plains and Delta regions also could have avoided power outages while saving consumers in excess of $100 million with an additional 1 GW of transmission ties to power systems to the east (Goggin 2021).

FERC et al. (2021) note that limited interconnections between the Texas grid and its neighbors significantly affected its ability to make up for the capacity shortage experienced during the severe cold weather event of February 2021. MISO and SPP, the grid operator in the Plains region, also reached transmission limits on imports during the February 2021 severe cold weather event, although neither region was as severely affected as ERCOT (FERC et al. 2021). MISO and SPP were less impacted given the strength of their connections with adjacent neighbors that were unaffected by the storm. Improving transfer capability via increased ties with neighboring regions would increase ERCOT's ability to import power to address capacity shortages when its system is stressed under emergency conditions.

However, FERC et al. (2021) also comment that MISO and SPP would have been limited in their ability to increase exports to ERCOT during this event—had additional transfer capacity been available—without increased import capability with their adjacent neighbors in the Eastern Interconnection. The coincident scarcity of generation resources among ERCOT's immediate neighbors during this event calls into question the value of increased transfer capability limits without an accompanying increase in multiregional transfer capability, thereby making the power grid larger than the weather systems that impact it.

During the "bomb cyclone" cold snap across the northeastern regions in January 2018, the affected regions—New England, New York, and the Mid-Atlantic—could have saved $30–$40 million for each GW of stronger transmission ties among themselves or to other regions (Goggin 2021). These regions routinely switched between importing and exporting as the most severe cold migrated among the regions over the course of the 3-week event, demonstrating that transmission interconnecting multiple regions can benefit consumers across a broad geographic area. In addition, an additional GW of transmission capacity between eastern and western PJM, the grid operator for much of the Mid-Atlantic, would have provided over $40 million in net benefits during this event. Likewise, the "polar vortex" event in the Midwest in 2019 illustrates the benefits of transmission interconnecting multiple regions. As the extreme cold moved eastward from the Midwest to the Mid-Atlantic, operators were able to switch the direction of power flow to serve customers in need (Goggin 2021).

Increased connectivity between the Delta and Midwest could improve reliability and resilience in those regions, as evidenced by recent weather events. The Cold Weather Bulk Electric System Event in January 2018 resulted in transfers exceeding the Regional Directional Transfer Limit between the Midwest and Delta regions and resulted in transmission limitations that prevented the Midwest from reaching the Delta region (FERC and NERC 2019). FERC and NERC (2019) note that the Delta region nearly experienced load shedding during the cold weather event and required emergency energy purchases at one point during the event. The February 2021 winter storm event exacerbated these issues when generation loss in the Delta region and the declaration of a Maximum Generation Event caused multiple requests for a Regional Directional Transfer Limit increase to deliver more energy to the Delta region from the Midwest (MISO 2021). Most of these requests were denied as neighboring regions were experiencing similar constraints (MISO 2021). Similarly, Hurricanes Laura and Ida exposed further weaknesses in the

Delta region's connectivity, especially in certain transmission constrained areas, some of which experienced load shedding (Potomac Economics 2020).

Winter Storm Elliott's freezing temperatures disrupted reliability throughout large portions of the United States—including the Southeast and Mid-Atlantic—for several days in December 2022. The storm led to shutdowns or diminished output at certain generating units and triggered rolling blackouts for some customers in the Southeast region. Utilities relied heavily on imports from other regions during the storm, including imports of up to 5 GW from MISO (MISO 2023). Duke Energy reported a loss of approximately 1,000 MW of resources in the Southeast and blackouts occurred as customer demand exceeded projections (Duke Energy 2023). Tennessee Valley Authority (TVA) customers also experienced outages as several of TVA's generating facilities were unavailable throughout the Southeast region (TVA 2023). PJM reported forced outages of 24% of its total capacity in the Mid-Atlantic region, with losses primarily from natural gas and coal generation (PJM 2023b). However, PJM avoided outages in part because of its interregional transmission capacity (RMI 2023).

Goggin and Zimmerman (2023) assess the widespread impacts of 2022's Winter Storm Elliott on the Southeast region and analyze the hypothetical benefits that the region could have realized if it had additional connections with neighboring regions. They find that an additional GW of transmission between TVA in the Southeast and ERCOT in Texas would have generated consumer savings valued at an estimated $95 million during the 5-day storm. An additional one GW of transfer capacity between parts of MISO and TVA in the Southeast could have offered $75 million in value during the storm if connecting with Louisiana in the Delta region and $79 million if connecting with Illinois in the Midwest region (Goggin and Zimmerman 2023).

Winter Storm Elliott also highlighted the value of within-region transmission to support interregional transfer capability. During the storm, multiple transmission constraints within PJM's footprint in the Mid-Atlantic limited PJM's ability to support export transactions across its southern interfaces. In other words, because of the complex nature of transmission flows, interregional transfer capability can be limited by insufficient transmission capacity internal to a region (PJM 2023b).

The impacts of weather-related transmission outages can be widespread and severe. In MISO's *2020 State of the Market Report*, Potomac Economics (2021a) reports that transmission issues arose because of generation and transmission outages and the impact of Hurricane Laura in MISO South. Hurricane Laura damaged the Entergy transmission system and isolated load in southwestern Louisiana and the eastern parts of Texas that are in MISO South, forcing more than 6 GW of generation out of service. More than 500 MW of firm load was curtailed as a result (Potomac Economics 2021a). NERC (2022a) comments on the widespread outages in the Delta, Southeast, Texas, and Florida regions due to recent hurricanes, most notably Hurricane Ida in 2021. Over 1.2 million customers lost power and over 210 transmission lines were out of service due to Ida (NERC 2022a). Finally, transmission and other energy infrastructure is also vulnerable to the compound hazards of sea level rise and storm surge. As many as 40% more power plants and transmission substations along the Gulf Coast in Texas and the Delta could be exposed to increased risk for category 1 hurricanes under different sea level rise scenarios

(Bradbury 2015). The impacts of Hurricanes Laura and Ida emphasize the importance of improving resilience and hardening transmission infrastructure.

Maintaining system reliability in the face of severe weather is crucial for states like California, which balances severe weather as well as other extreme events, such as earthquakes and wildfires. California has become increasingly susceptible to extreme seismic risk (Field et al. 2017). Humboldt County in northern California, for example, is one of the most seismically active areas in the state because of the convergence of three tectonic plates (USGS 2022). In 2022, Humboldt County experienced a 6.4 magnitude earthquake, resulting in outages for roughly 70,000 customers (PG&E 2022). Increased seismic activity in an area that is already seeing increasing trends of sustained outages (PG&E 2021) could result in further grid-related issues.

High ambient temperatures in California are also increasing in both intensity and duration. A 2020 heat wave resulted in two rotating power outages, while another in 2022 increased average maximum daily temperatures by 5°F–15°F and forced demand on the grid to reach a new instantaneous gross peak record load of 52,000 MW (CAISO 2022a). Extreme heat in 2021 also impacted the Northwest grid, causing localized power outages (NERC 2022a). Transmission outages can also occur due to wildfires, particularly in California and the western United States, which can become exacerbated by extreme heat and drought. NERC (2022a) reports one major transmission system outage due to wildfires in 2021. As summer heat waves become more frequent and severe, the value of transmission for delivering needed electricity supplies from regions that are currently less affected will grow.

Transmission planning entities are increasingly accounting for risk from extreme weather events in their longer-term transmission plans. WECC is considering incorporating weather and climate data into load forecasts to help inform system planners in the California, Northwest, Mountain, and Southwest regions on whether transmission investments will serve both the changing demands of the system and be resilient against extreme events (WECC 2023). SPP recommends expanding its transmission planning scenarios to consider more extreme transmission contingencies and additional extreme weather to account for increasing frequency and volatility of weather patterns in the Plains region (SPP 2023). SPP notes that more extreme weather patterns will lead to more extreme load patterns, making load more difficult to forecast.

NERC (2022a) notes that the ability of the power grid to withstand and recover from extreme events is increasingly important as the intensity and frequency of severe weather grows due to climate change. Interregional transmission investments will help improve system resilience by enabling access to diverse generation resources across different climatic zones.

Increased grid connectivity can support resource adequacy

Resource adequacy is the ability of supply- and demand-side resources to meet the aggregate electrical demand of a region (NERC 2022b), including under extreme conditions when critical generators may become unavailable. Regions meet their resource adequacy requirements through a mix of regional generation, demand response, and firm capacity transfers across intra- and interregional transmission lines.

Patton et al. (2021) assert that new transmission capacity can provide substantial resource adequacy benefits, as new lines enable more flexible generation sharing, reducing the need for new generation. Brinkman et al. (2021) note that transmission is needed in the near term for resource adequacy, and more importantly in the long term due to the anticipated increase in clean energy resource integration. Brinkman et al. (2021) also conclude that transmission expansion can provide economic benefits and improve grid reliability by maintaining resource adequacy. MISO (2022a) similarly reports that its LRTP portfolio will expand system transfer capacity, allowing for utilities to use new or existing resources from elsewhere in the Midwest region rather than constructing new, local generation to meet resource adequacy obligations.

Ardani et al. (2021) and Bloom et al. (2020) similarly explain that expanding transmission can help ensure resource adequacy needs by allowing regions to access a diverse set of resources from outside of their respective footprints. CAISO's *20-Year Transmission Outlook* identifies a combination of new and existing transmission resources that could deliver 12,000 MW of out-of-state wind to the CAISO system by 2040, improving resource diversity (CAISO 2022b). SPP's Future Grid Strategy Advisory Group notes that establishing and improving resource adequacy coordination processes can also lower infrastructure development costs in the Plains region, while improving grid resilience (SPP 2023). Additionally, connecting geographically diverse resources can help reduce electricity costs by reducing the need for excess generating capacity, particularly for regions that have non-coincident demand peaks. Ardani et al. (2021) explain that DERs can offset the need for some transmission resources in ensuring resource adequacy by shifting diurnal peak demand. Xu et al. (2021) assert that given current assumptions about the future, substantial transmission investments will be necessary to ensure reliable renewable generation deliverability and system adequacy.

Novacheck et al. (2021) emphasize that even during extreme events of low wind and solar output, VERs can contribute to resource adequacy via interregional coordination and bidirectional trading of power through the transmission system. Although the historical high-impact weather events considered by Novacheck et al. (2021) did not lead to new operational or resource adequacy concerns for an electricity system with high VER penetration, the report notes that milder versions of these weather events of increasing frequency can result in prolonged periods of low variable energy availability. For example, wind generation tends to decrease during periods of prolonged cold weather after a cold front moves through an area. These periods can pose challenges to resource adequacy as solar output is typically already lower during the winter months. Similarly, moderate heat waves accompanied by persistent high pressure can depress wind generation during evening net load peak. Expanding transmission to integrate geographically diverse VERs can reduce these risks, lower capacity reserve margins, and reduce system costs. Resource adequacy studies do not fully consider these milder weather events, however, and therefore current planning to ensure enough generation and transmission infrastructure exist to meet load is likely insufficient.

ISO-NE's *Future Grid Reliability Scenarios* study (ISO-NE 2022a) uses a resource adequacy reliability analysis to explore what conditions will likely present operational or reliability issues under future New England grid scenarios. ISO-NE finds that scenarios without dispatchable units require a significantly larger buildout of renewable generation. The *Future Grid Reliability Scenarios* study also finds that resource diversity is critical. In cases for which only a single generation type is added, future scenarios either do not meet reliability criteria or require what may be infeasible quantities of those resources. Generation diversity—including combinations of onshore and offshore wind, solar, battery storage, and hypothetical dispatchable emission-free resources—reduces the need for new generation and storage resources by up to 17,000 MW per the study. This analysis finds that resource adequacy criteria can be met by a variety of diverse resource mixes, but that dispatchable resources are particularly effective at providing resource adequacy.

Prabhakar et al. (2021) conduct modeling to assess the reliability of the electric system with increasing levels of wind and solar in the Midwest and Delta regions. The report finds that no transmission solutions are needed for resource adequacy purposes at up to 30% wind and solar penetration due to over-builds in renewable capacity. However, beyond 40% wind and solar penetration, the report finds that new transmission is necessary.

RTOs/ISOs identify a need for transmission upgrades and new construction in their long-term plans, driven by dispatchable generator retirements and rapid increases in renewable capacity (ERCOT 2022b; ERCOT 2022c; MISO 2022a). Similarly, utilities in the Midwest also identify the need for additional transmission infrastructure to support system reliability as the generation fleet transitions to incorporate more non-dispatchable resource capacity and retires an increasing number of dispatchable generators (CapX2020 2020). The utilities note that additional transmission between regions will support increased grid flexibility and system stability by allowing for capacity imports and exports between regions to ensure that energy needs are met for all hours of the year.

PJM (2023a) studies the impacts associated with the energy transition in the Mid-Atlantic region with a focus on resource adequacy in the near term through 2030. The study findings highlight that reliability risks may arise in the near term, largely driven by electricity demand growth due to high-demand data center development in the region, economic and policy-driven thermal generator retirement that outpaces new resource development, and the increase in intermittent and limited-duration resource interconnection requests. PJM notes that it may need to order transmission upgrades or additions built by transmission owners in the region to maintain resource adequacy and accommodate generation loss in the face of these anticipated reliability risks.

NERC (2021) finds that generation retirements over the next few years in the Midwest and Delta regions will result in capacity shortfalls as early as 2024 without additional generation or import transfer capacity additions. By 2026, MISO's reserve margin capacity shortfalls will be an estimated 3 GW (NERC 2021). NERC stresses that resource adequacy and energy sufficiency measures need to be urgently implemented in the area. MISO planners similarly predicted capacity shortfalls in previous iterations of the Organization of MISO States' MISO survey (NERC 2021). While the shortfalls ultimately have not yet occurred, the continued identification of capacity shortfalls as a concern for the Midwest and Delta regions emphasizes the persistent need for resource adequacy measures, such as new transmission to access additional resources and improve overall resource diversity.

Regions in the Western Interconnection face even more immediate concerns as current resources are insufficient to meet demand during widespread heat events, particularly without resource diversity to complement the loss of solar generation in the late afternoon. In 2021 NERC estimated the Northwest could see 23 load-loss hours in 2022 and the Southwest has the potential for load-loss hours starting in 2024 (NERC 2021). NERC further estimated that California could face up to 10 hours of load loss beginning in 2022 and 75,000 MWh of unserved energy as soon as 2024 given the extreme heat events considered in its analysis. By 2026, California will experience an estimated 3 GW of capacity shorfalls (NERC 2021). Additional interregional transfer capacity is one means to make up for these reserve margin shortfalls, so long as neighboring regions have excess generation to export at the time of need.

FERC et al. (2021) recommend that adjacent reliability coordinators, BAs, and transmission operators perform bidirectional power transfer studies to determine constraints that could occur when importing or exporting power between neighboring regions during an emergency that spans multiple reliability coordinator/BA areas. NERC (2021) makes a similar recommendation, recognizing that resource planners in the Western Interconnection are increasingly reliant on external transfers to meet capacity reserve margins. This dependence on import capacity will require coordinated resource adequacy and transmission planning to ensure reliability.

In the Southeast, Georgia Power Company's *2022 Integrated Resource Plan* proposes a Reliability & Resilience Action Plan to address future reliability needs associated with the potential for future fossil generator retirement in northern Georgia (Georgia Power 2022). Specifically, the plan notes that northern Georgia relies on transmission to transfer power from areas to the south, and in the event of generator retirement, existing transmission infrastructure is not sufficient to support reliable electric service to the north.

In Alaska, Financial Engineering Company (2022) analysis finds that planned and anticipated thermal resource retirements in the northern Railbelt region will require capacity replacement from new renewable resource installations and power purchase agreements with southcentral gas generators to ensure resource sufficiency. The increase in capacity from gas power purchase agreements requires an upgrade of the Alaska Intertie to allow increased capacity delivery to the north.

Interregional transmission across the interconnection seams can improve reliability and resilience

Like resource adequacy, greater interregional transmission connectivity can provide increased reliability and resilience value. This value is particularly highlighted when connecting across the three interconnection seams.

As discussed in Section IV.b, Millstein et al. (2022a) calculate hourly transmission congestion values between different links in the contiguous United States from 2012 to 2021. They find that very few hours (5%) account for a large portion of transmission value and that a small number of extreme events (1–3 over 10 years) contribute meaningfully to the total 10-year value of a particular link. The transmission value that Millstein et al. (2022a) calculate could therefore be considered "insurance" against the high costs faced during extreme grid conditions, weather events, or other factors, such as unexpected deviations from forecasted conditions. Each stakeholder's potential benefits from this insurance value of transmission depends on the characteristics of future extreme grid conditions or weather events that are unpredictable. The attribution of this complex value is another challenge transmission planners face as they strive to weigh the costs and benefits of transmission expansion projects. Transmission planners run the risk of understating the benefits of regional and interregional transmission if extreme conditions and high-value periods are not adequately considered (Millstein et al. 2022a).

As noted above, the February 2021 winter storm event had reliability implications across the Texas, Plains, and Delta regions. As FERC et al. (2021) observe, unlike other regional markets like MISO and SPP that were also affected by the severe cold weather event, ERCOT has very limited interconnections with its neighbors. ERCOT can only import just over 1,000 MW across its ties to its neighbors, which significantly affects its ability to make up for the region's capacity shortage. FERC et al. (2021) make recommendations to mitigate future outages of this magnitude within the Texas system,[43] one of which is that ERCOT conduct a study to evaluate the benefits of additional ties with the Eastern Interconnection, the Western Interconnection, or Mexico. The benefits could include increased import capability to help address capacity shortages during emergencies. Improving import capability would therefore help improve the overall reliability of the Texas system.

Bloom et al. (2020) identify transmission expansion across the interconnections as a way to reduce generation capacity required for reliable grid operations, as diversifying load and generation across large geographic areas can increase operating flexibility. Xu et al. (2021) further conclude that high-voltage direct current (HVDC) connections that span across interconnection seams enable renewable resource generation to be shared more readily between interconnections. The authors argue that given existing assumptions about the future, sizable transmission additions are necessary to ensure system reliability. Clack et al. (2020b) comes to similar conclusions, arguing that continental-scale transmission—expanding from the Western Interconnection to the Eastern Interconnection to ERCOT and Canada—can improve reliability by capturing even greater geographic diversity of generation resources.

The interconnection seams could be further connected via back-to-back DC connections—as is the case now—or using AC transmission. Overbye et al. (2021) evaluate the potential to synchronize the Eastern and Western Interconnections using a combination of high-voltage alternating current and AC-DC-AC converter stations spanning the entire seam between the two interconnections. The study assesses stability issues that could arise with synchronization and finds that generator governor action could result in asymmetrical responses under contingency conditions. In the event of a generator loss contingency in the Western Interconnection, approximately 80% of the lost power will flow from east to west because the Eastern Interconnection has almost four times the load of the Western Interconnection. The authors conclude that the interface joining two such grids would need reinforcing to handle the possible increase in flow that would occur under contingency conditions.

[43] FERC et al. (2021) make 28 recommendations in all, many of which relate to preparing generation units to operate in cold temperatures and using more reliable weather, resource, and load forecasts.

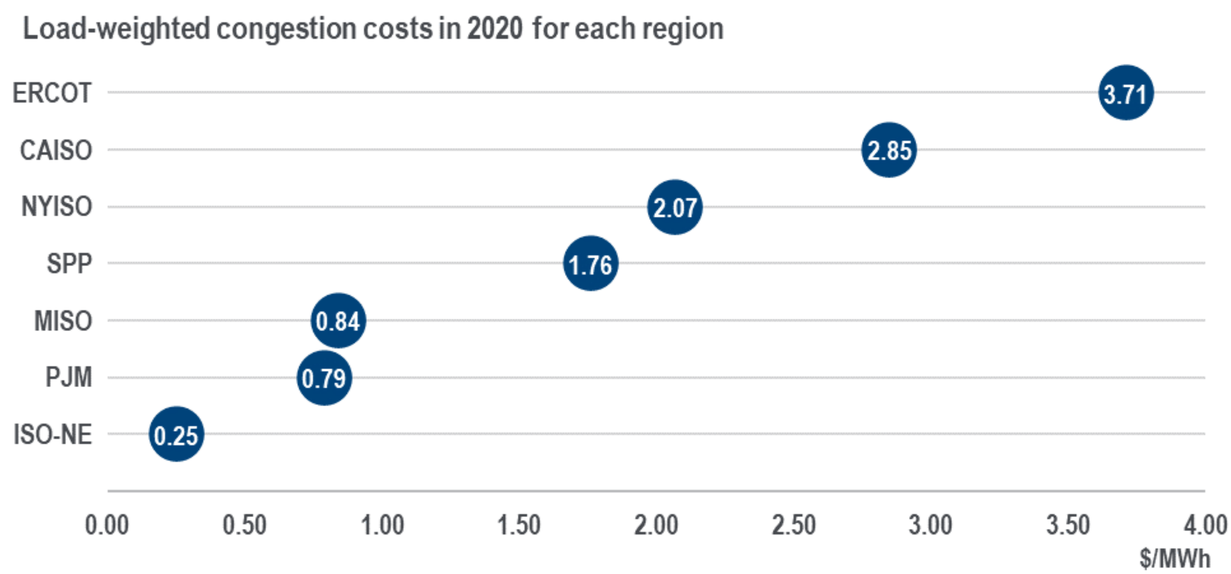
V.b. Regional Congestion and Constraints

Congestion is another major indicator of transmission need; various reports reviewed discuss congestion and constraints as a driver of transmission infrastructure needs in several regions, including Ardani et al. (2021), Pfeifenberger (2021), FERC (2020), and NERC (2021). Transmission congestion between lowest-cost generation sources and load may require higher cost generation sources that are not impacted by congestion to serve load, raising wholesale electricity prices for those customers. FERC (2020) indicates that transmission investments can improve the competition of lowest-cost resources in wholesale markets by reducing congestion. In unconstrained cases, where the transmission system is modeled as a single-bus system in which transmission has unlimited capacity, no wholesale market price separation exists (ISO-NE 2021). New deployment of transmission, along with storage and other alternative transmission solutions (discussed further in Section V.d.), can alleviate congestion. If a transmission facility is being considered for the sole purposes of alleviating congestion, the cost of the project would need to be less than the congestion costs that are alleviated for the project to be financially viable.

MISO (2022a) relies on congestion and fuel cost savings as another one of many quantified benefits gained from the transmission projects proposed in their LRTP Tranche 1 Portfolio. The congestion value of transmission calculated by Millstein et al. (2022a), discussed in Section IV.b, is derived from the value of allowing a lower cost set of generators to meet load and by increasing operational flexibility through reduced congestion and increased interregional trade. Thus, value can also be thought of as the potential to reduce system cost through reducing congestion. In other words, properly accounting for the full suite of values that derive from transmission is critical toward building a least-cost electricity system.

This section discusses transmission congestion found in each region, primarily using utility industry and market monitor reports in each area. RTO/ISO market monitor reports identify the costs incurred in each market (and ultimately borne by consumers in most cases) due to transmission congestion and constraints. Less granular data on how transmission congestion and constraints raise overall system costs for consumers is available in non-RTO/ISO regions.

Figure V-2 shows a summary of 2020 load-weighted congestion costs in each RTO/ISO market from the reviewed market monitor reports. Load-weighted congestion costs are highest in Texas and California.



Source: ISO New England (ISO-NE 2021b, p. 120), Potomac Economics (Patton et al. 2021b, p. 26), Southwest Power Pool, Inc. (Warren et al., 2021 p. 198), Monitoring Analytics, LLC. (Monitoring Analytics, LLC. 2021, p. 69), Potomac Economics (Potomac Economics 2021a, p. 59), California Independent System Operator (Hildebrandt et al. 2021, p. 195 for DA and p. 111 for RT congestion), and Potomac Economics (Potomac Economics 2021b, p. 47). Midcontinent Independent System Operator (MISO) system load calculated from MISO 2020 Regional Actual Load, which can be found at (MISO 2020). Electric Reliability Council of Texas (ERCOT) system load taken from 2020 Demand and Energy Report (ERCOT 2021a).

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-2. 2020 load-weighted net congestion cost by region.

While historic transmission investments in New England have resulted in low congestion, future generation changes are expected to increase congestion in some areas.

Patton et al. (2021a), in their 2020 assessment of the ISO-NE electricity markets, finds that ISO-NE has lower congestion costs compared with other RTOs/ISOs because of significant transmission investments over the past decade. These investments, however, have led the region to experience higher transmission service costs per MWh of load compared to ERCOT, MISO, PJM, and NYISO. ISO-NE experiences about 10%–20% of the congestion levels in other RTOs/ISOs as a result of these large transmission investments (Patton et al. 2021a). New transmission likely will not be needed in the near term to alleviate congestion internal to the ISO-NE system. NERC (2021) also states that transmission expansion in New England has improved reliability and resilience, reduced air emissions, and lowered wholesale electricity market costs by nearly eliminating congestion.

Patton et al. (2021a), however, describe the effect of transmission limitations on import capability in certain parts of the ISO-NE region. The assessment states that the combined lower Southeastern Massachusetts (SEMA) and eastern Rhode Island area is import constrained, and further transmission maintenance outages can reduce import capability from New Hampshire to Maine and increase reliability commitments in Maine.

Additionally, ISO-NE (2020) notes that transmission enables low-cost resources to produce more energy, lowering wholesale electricity prices for several subareas. However, the study also finds that an increase in low-cost offshore wind interconnection in the SEMA/Rhode Island subarea intended to serve load outside of the subarea is expected to increase congestion at the SEMA/Rhode Island export interface due to an oversupply of wind generation. Additional transmission to connect load centers in Connecticut and Massachusetts to this available offshore wind generation can alleviate this challenge. Further transmission expansion could be needed to avoid transmission-related wind curtailment, some of which can be avoided by developing resources near load centers. ISO-NE (2021) states that building extensive low production cost generation in one area, rather than near load centers, increases congestion, creating a need for new transmission.

The New England region is planning for interconnections of large amounts of offshore wind energy in the next several years. Selecting appropriate points of interconnection for offshore wind requires tradeoffs between costs, interconnection size, and risk of overloads. To address these tradeoffs, ISO-NE suggests a standard offshore wind farm size of 1,200 MW for points of interconnection in the Boston area, which would reduce the potential for overloads and limit the required number of HVDC converter stations (ISO-NE 2022b). Larger interconnections would be possible outside of the Boston metropolitan area, according to ISO-NE.

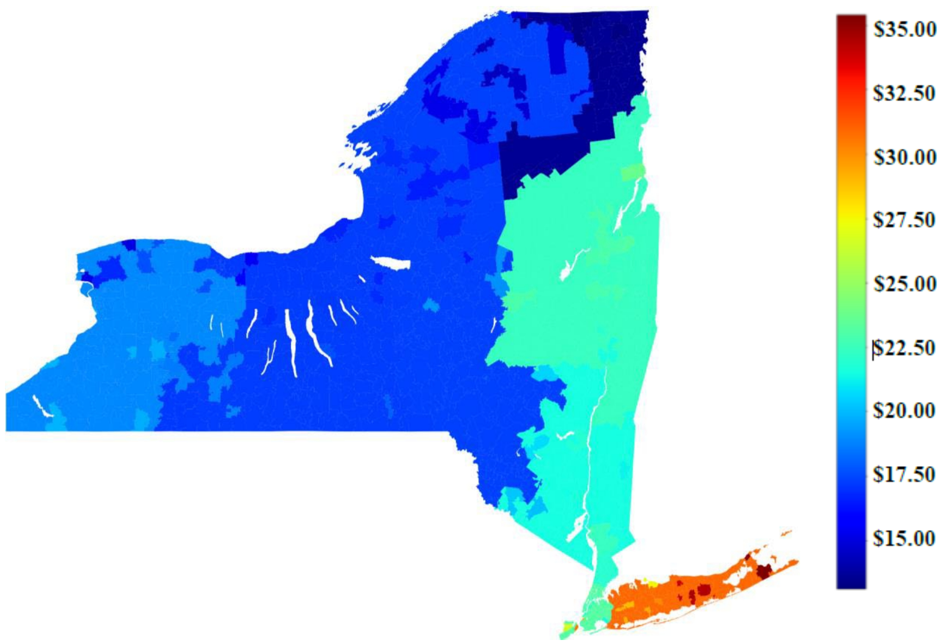
Largest transfer limitations within New York are between upstate and Long Island

In NYISO's *2020 State of the Market Report*, Patton et al. (2021) report that the COVID-19 pandemic reduced demand and had a larger effect on commercial customers than other customers. Thus, the decline in load was more pronounced downstate, which reduced congestion from upstate to downstate. Energy prices ranged from an average of $13.28/MWh in the North Zone to $28.03/MWh in Long Island due to transmission congestion and losses. However, congestion overall declined relative to 2019 because of lower load levels from the pandemic and lower natural gas prices. Day-ahead congestion revenues fell 31%, from $433 million in 2019 to $297 million in 2020, the lowest level since NYISO began operation. Still, the Central-East interface, which usually accounts for the largest congestion, continued that trend in 2020, with 39% of total day-ahead congestion value. Top congested corridors included the West Zone (19%), Long Island (17%), and New York City (8%). Average 2020 real-time energy prices and congestion in NYISO are shown in Figure V-3.

Transmission outages and other factors that limit transmission capability resulted in day-ahead congestion shortfalls. The most significant was the lengthy outage of a high-capacity 345 kV circuit. Outages on two submarine HVDC lines into Long Island also caused significant congestion. Further, transmission outages related to the construction of the Moses-Adirondack Smart Path Reliability Project, a project meant to help New York reach its public policy goals, resulted in reduced transfer capability out of the North Zone.

NYISO also improved the efficiency of scheduling and pricing in some areas by reducing the use of out-of-merit actions to manage constraints on low-voltage lines. In 2018, NYISO started incorporating some 115 kV constraints in the market software, reducing out-of-merit generation actions used to manage these constraints from 260 days in the West Zone in 2018 to 13 days in 2020 and from 130 days to 8 days in the Capital Zone over the same timeframe.

The 20-year outlook of New York's system resources and transmission constraints also anticipates further congestion issues. To meet the state's Climate Leadership and Community Protection Act's goals by 2030 and 2040, additional renewable generation is needed. NYISO has identified that the local and bulk transmission systems are inadequate to achieve these goals, limiting effective delivery of renewable energy to consumers. Long-term planning scenarios with a significant portion of renewable generation would exacerbate existing transmission congestion with a 23% increase statewide by 2030 (NYISO 2022a).



Source: State of the Market Report for NYISO 2020 (Patton 2021b).

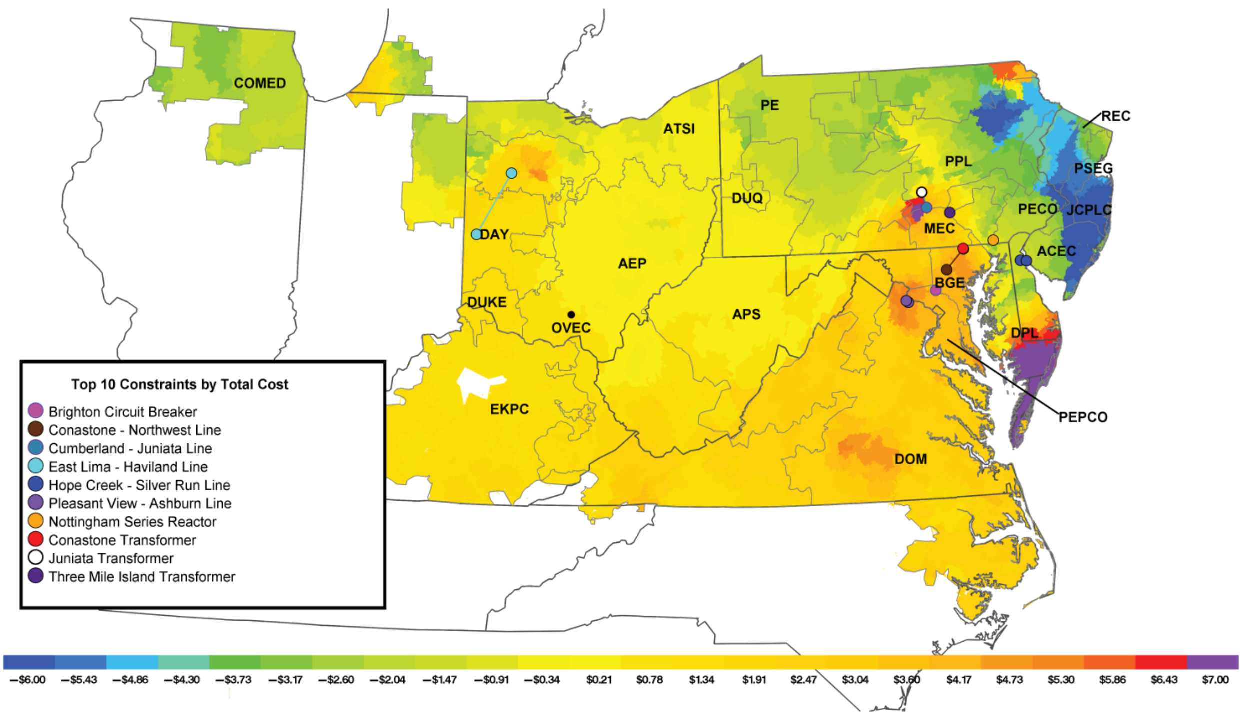
Figure V-3. Real-time energy and congestion prices ($/MWh) in NYISO in 2020.

Significant congestion and constraints exist in the eastern, coastal Mid-Atlantic

In PJM's 2021 *State of the Market Report*, Monitoring Analytics (2022) records that total congestion costs increased in 2021, from $528.7 million in 2020 to $995.3 million in 2021, an approximately 88.2% increase. The top 10 facility constraints with regionwide impact are shown in Figure V-4, along with average 2021 congestion costs in the PJM region. A portion of the congestion associated with these constraints is a result of scheduled transmission outages to accommodate system upgrades.

Monitoring Analytics (2022) also provides information on transmission constraint shadow prices, which represent the marginal change in total production cost from relieving a constraint by 1 MW and can signal congestion on certain lines. The average shadow price of PJM's internal transmission constraints almost doubled, from $92.23 in 2020 to $183.04 in 2021. For the first time since 2007, the cost of the transmission price component was more than the capacity price component for the wholesale energy price (on a per MWh basis), which shows a need for transmission upgrades within PJM to reduce congestion.

Monitoring Analytics (2022) also describes the impact of TLR in PJM and neighboring regions. According to the report, the impact of TLR procedures issued by PJM decreased in 2021, compared with 2020. PJM issued two Level 3a or higher TLR procedures each in 2020 and 2021, but no related curtailments occurred in 2021, compared with 1,789 MWh of curtailments in 2020. Monitoring Analytics (2022) indicates, however, that during the same period, curtailments related to MISO and NYISO transmission load relief increased. The number of curtailments MISO issued decreased from 93 in 2020 to 75 in 2021, but curtailments increased from 58,520 MWh to 70,231 MWh, respectively. Monitoring Analytics (2022) adds that NYISO issued three Level 3a or higher TLR procedures in 2021 compared with two in 2020. Related curtailments increased sharply, from 1,030 MWh in 2020 to 27,754 MWh in 2021. As described in Section III.d., TLR only partially describes the congestion in RTOs/ISOs in which real-time transmission congestion is predominantly managed in the wholesale electricity markets. Nevertheless, the large increase in curtailments of generation show a need for transmission to alleviate constraints and allow energy from these resources to flow to consumers.



Source: Monitoring Analytics (Monitoring Analytics 2022).

Figure V-4. Location of the top 10 constraints by total congestion costs: 2021 ($/MWh).

Significant constraints and congestion exist between the Midwest and Delta

In MISO's *2020 State of the Market Report*, Potomac Economics (2021a) records that congestion costs in MISO increased because of increased wind output, generation and transmission outages, and the impact of Hurricane Laura in the Delta region of MISO, highlighting the importance of transmission to increased system resilience. Potomac Economics

(2021a) reports that MISO's Regional Directional Transfer Limit was frequently binding from south to north because of higher-than-normal temperatures in the Midwest region of MISO, meaning that available generation in the Delta region of MISO could not be dispatched to serve Midwest customers with high cooling load needs. Flows were correlated with wind in other months. All wind resources within MISO are currently located in the Midwest region, and as a result, generation from wind resources flows north to south when wind generation is high and in the reverse direction when wind generation is low. The ability to shift the quantity and direction of flows provides significant value to customers as the lowest-cost available generation switches between the Midwest and Delta regions. Congestion between the two regions prevents low-cost generation from reaching customers on the other side of the transfer limit. Similarly, these findings highlight the need for increased access to a more diverse generation portfolio, which can be achieved through additional interregional transmission.

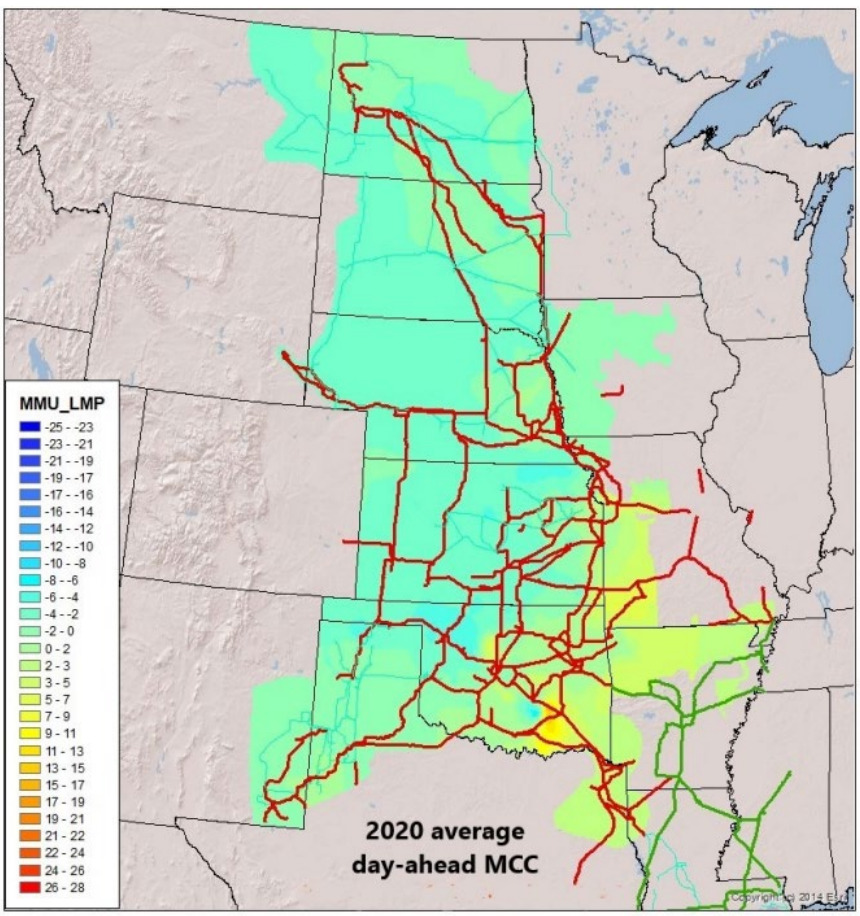
Despite lower gas prices and transmission upgrades in MISO, the value of real-time congestion rose by 26% to $1.2 billion in 2020 relative to 2019. Although congestion in the South and Central regions fell, congestion in the North region more than doubled because of increased wind output. The use of conservative static ratings and limitations of MISO's authority to coordinate outages contributed to higher than optimal real-time congestion. MISO has no authority to deny or postpone planned outages, even if such action would result in significant economic benefits. The Independent Market Monitor recommends that MISO files for increased authority to coordinate planned transmission and generation outages to reduce unnecessary economic costs.

According to Potomac Economics (2021a), congestion also affects MISO's interchange with neighboring markets. MISO's market-to-market (M2M) process serves to efficiently and cost effectively manage constraints affected by MISO and its neighboring RTOs by providing a mechanism for the RTO with the more economic redispatch to relieve congestion. The M2M process compensates the RTO with the lower cost of managing the constraint the marginal value of constraint relief. Congestion on MISO's M2M constraints increased 37% in 2020 to $530 million (45% of all congestion in MISO) relative to 2019. MISO uses M2M processes to manage congestion on MISO constraints that are also affected by generation in PJM in the Mid-Atlantic and SPP in the Plains (and vice versa). High wind generation along the seams with SPP and generator retirements contributed to a 400% increase in M2M payments ($80 million net payment) from MISO to SPP. MISO's external market monitor recommends measures to improve the M2M coordination and reduce M2M congestion costs.

In addition, Potomac Economics (2021a) describes the negative impact on the MISO market of TLR with MISO's neighbors. For example, TLR procedures called by the Independent Electricity System Operator of Ontario (IESO) in Canada resulted in curtailments of large amounts of power from PJM to MISO, creating price spikes in MISO. Potomac Economics (2021a) also finds that TVA generation in the Southeast could have relieved $63 million in congestion costs in MISO caused by TLR constraints. MISO's external market monitor recommends that MISO coordinate with TVA and IESO to develop mitigation measures.

Congestion in the Plains is related to limited transmission capacity and high wind generation output

In SPP's *2020 State of the Market Report*, SPP's external market monitor (Warren et al. 2021) records that congestion due to high wind generation output and transmission limitations affected 2020 pricing in some locations. The southeastern corner of SPP, including eastern Kansas, southwestern Missouri, and southeastern Oklahoma experienced the highest congestion costs. Figure V-5 shows a map of average 2020 day-ahead congestion costs, as reflected in the marginal congestion component of the locational marginal price. Net congestion costs totaled over $442 million because of high wind generation and transmission limitations. Congestion costs in 2020 were 8% lower than those in 2019. Price differences between the SPP North and SPP South hubs remained relatively small in 2020 ($0.23/MWh average day-ahead price difference) because of reduced congestion resulting from transmission expansion and a milder summer in the southern region. Transmission upgrades within SPP, including upgrades in the upper-central region of Oklahoma and central Kansas, have increased transmission capability for wind-producing regions and reduced prices in previously congested regions.



Source: Southwest Power Pool State of the Market 2020 (Warren et al. 2021).

Note: Transmission lines shown in cyan (<345 kV), red (345 kV), or green (>345 kV).

Figure V-5. Average day-ahead marginal congestion cost ($/MWh) in SPP in 2020.

In addition, SPP experienced an increase in M2M payments from MISO. Total payments from MISO were $82.8 million in 2020, compared with $17.5 million in 2019. This increase in total M2M payments demonstrates congestion at flowgates along the MISO-SPP seam has increased since 2019, particularly at flowgates in eastern Nebraska, southwestern Missouri, southeast and Northeast Kansas, as well as eastern Oklahoma, and northern and western Missouri. SPP's external market monitor recommends evaluating the processes and mechanisms between SPP and MISO through a joint study addressing the inefficiencies between the two markets. As MISO's wind penetration continues to increase, SPP's M2M flowgates will continue to be affected and potentially lead to an increase in the M2M payments from MISO. The M2M coordination study estimates a reduction of $35 million in annual congestion costs by automating processes that promptly identify and activate constraints in SPP and MISO's M2M systems.

In MISO and SPP's Joint Transmission Interconnection Queue (JTIQ) Study (MISO and SPP 2022), the system operators recommend a five-project transmission portfolio that relieves constraints in both markets, enables the interconnection of large amounts of renewable generation near the Midwest-Plains seam, and provides other significant benefits. The portfolio relieves 48 reliability constraints across both markets. The JTIQ Portfolio resolves constraints that allow MISO to interconnect over 28 GW of additional generation near the seam, while SPP estimates it would be able to interconnect over 53 GW of additional generation. The JTIQ study suggests that building additional transmission connections between SPP and MISO will reduce grid constraints and congestion costs borne by consumers and improve performance.

Constraints and congestion costs in the West are growing as the generation resource mix changes and demand grows

Hildebrandt et al. (2021) describe the impact of congestion in CAISO. Transmission constraints and greenhouse gas compliance costs result in higher prices in CAISO than in the areas of the Northwest, Mountain, and Southwest that participate in the WEIM. CAISO's *2020 Annual Report on Market Issues and Performance* identifies congestion in both the day-ahead and 15-minute markets in 2020. Locational price differences because of congestion in both the day-ahead and 15-minute markets increased in 2020, particularly as a result of constraints associated with major transmission congestion on lines between Northern and Southern California and on those connecting CAISO and the Northwest.

Congestion on interties across all markets (day-ahead, 15-minute, and 5-minute) increased by 74% from $152 million in 2019 to $263 million in 2020. This increase was primarily due to increased congestion on the two major interties linking CAISO with the Pacific Northwest, where total congestion charges tripled to $236 million in 2020 relative to 2019 as a result of increased import congestion frequency on the interties during the third quarter. In California overall, congestion resulted in higher prices in Southern California load zones, and lower prices in the Northern California load zone.

Emerging trends in load and generation changes will have a large impact on future interregional transmission capacity utilization in the Western Interconnection. The WECC *2028 Scenario Reliability Assessment* (Bailey and Mignella 2020) examines utilization along transmission paths in a 2038 reference case and four additional scenarios. The most highly utilized paths may need to be expanded if existing transfer capacity cannot meet future generation and demand needs. Many paths are expected to be highly utilized in the near- to mid-term, but the level of utilization of these paths is expected to increase significantly by 2038. Because of the displacement of coal generation, the Western Interconnection becomes more dependent on generation in the western Mountain and the Southwest regions to meet energy needs, and the eastern Mountain region switches from a net exporter to a net importer.

Demand in California continues to be a significant factor impacting the Western Interconnection. Transmission paths with high utilization include those that facilitate transfers from the western Mountain and Southwest regions to California and the eastern Mountain region and those that support transfers from the Northwest to California. The increase in solar generation in California has resulted in bidirectional flows on some of these congested paths, sending energy in the opposite direction when solar production within California is high. Path congestion occurs during periods of heavy ramping or during energy deficiency periods in California. While periods of congestion are shorter now given the bidirectional nature of power flows, they are of increased criticality for reliability (Lauby 2022). See Section IV.c. Qualified Paths for a more detailed discussion on congested paths.

California expects to interconnect offshore wind projects within the next several years. CAISO evaluates transmission needs for both the Humboldt and Morro Bay wind energy areas, located in the northern and central parts of the California coast, respectively. The Humboldt area has especially limited transmission infrastructure, and CAISO projects the need for two 500 kV AC lines and an HVDC line. CAISO is considering both overland and undersea options for the Humboldt HVDC cable (CAISO 2022b). Similar discussions are ongoing about interconnection needs for potential offshore wind development off the Oregon coast in the Northwest (NorthernGrid 2023).

Texas anticipates major east–west in-state congestion as demand grows

ERCOT assesses transmission congestion for a range of future scenarios in its *Long-Term System Assessment* (ERCOT 2022c). The assessment finds that projected growth in renewable energy and electric vehicle adoption results in a shift in scarcity hours to later in the day, and that the system faces transmission limitations both in the parts of Texas with significant renewable generation capacity, like West Texas, as well as on paths into demand centers, like Houston (ERCOT 2022c). The West Texas Export Interface represents the most significant congestion constraint on ERCOT's system (ERCOT 2022d). To alleviate this challenge, ERCOT is considering increased capacity in the West, including a 1.5 GW HVDC line, as well as improvements closer to demand centers (ERCOT 2022b; ERCOT 2022c). ERCOT also notes that the Dallas-Fort Worth area experiences substantial congestion in the Current Trends scenario because of local load growth and new generation to the Northwest (ERCOT 2022c). Other congestion challenges are anticipated throughout the state based on expected retirements, new capacity, and changes in demand patterns.

Alaska has limited transmission transfer capacity between generation and major load centers

Alaska's Railbelt power system has two critical interties with limited transfer capacity. The Alaska Intertie, a 78 MW-rated transmission tie, interconnects service regions to the north with southern utilities, and the Kenai Intertie, a 75 MW-rated transmission tie, interconnects the Kenai Peninsula to service areas to the north (Denholm et al. 2022b). Service regions interconnected through the interties maintain sufficient generation reserves and can operate largely independently due to limited transfer capacity and the potential for intertie failures to lead to system-wide transmission outages. AEA's *Railbelt Transmission Plan* finds the need to increase transfer capacity for both the Alaska Intertie and the Kenai Intertie (AEA and EPS 2017). Most recently, AEA (2022) describes that planned deliverable capacity improvements to a hydroelectric generation facility on the Kenai Peninsula in Alaska providing roughly 10% of total annual electrical energy used by Railbelt electric utilities will require transmission upgrades to reduce constraints and increase capacity exports from the Kenai Peninsula to the north.

Outside of the Railbelt service region, rural Alaskan communities are served largely by stand-alone microgrids. Across the state, there are more than 150 isolated microgrid systems that are not interconnected with the Railbelt or other rural utilities (Lovecraft et al. 2023). The vast majority of these systems rely on imported diesel fuel to meet electrical, space and water heating, and transportation requirements. Conditions in many rural villages, however, can make road transport of diesel fuel infeasible, causing diesel prices in areas requiring air or barge fuel delivery to be up to four times more expensive than fuel delivery in areas within Alaska with road transport access (Allen et al. 2016).

EPA (2020) notes that one method to reduce diesel consumption in rural Alaska is to construct electrical interties between isolated communities. Multiple studies have also been conducted to assess the potential for new transmission to interconnect rural communities to the larger Railbelt transmission system. A recent example includes a technical feasibility assessment of the development of a Roadbelt Intertie to interconnect islanded road system power utilities east of the Railbelt system, creating an additional transmission parallel to the existing Alaska Intertie (Ahtna and EPS 2020). The analysis demonstrates the project is feasible and has the potential to increase power transfers over time with the integration of new generation sited along the corridor. Stakeholder feedback suggests the project would potentially reduce power costs for rural communities, support regional economic development opportunities, increase U.S. Department of Defense facility resilience, and increase electric power reliability throughout the Alaska road system. Ahtna and EPS (2020) note that stakeholders in Alaska have studied the potential for increased transmission interconnection east of the Railbelt for over three decades and references 13 studies conducted since 1989 that relate to the proposed Railbelt Intertie.

Isolated transmission systems in Hawaii are reaching capacity

Hawaii's six main islands each have their own electric grid without any electrical interconnections between islands. Utility service providers for Hawaii island, Oahu, Maui, Lanai, and Molokai find existing transmission infrastructure on each island is approaching capacity limitations and will require additional transmission capacity as the islands continue to integrate renewable resources through ongoing and future procurement necessary to meet state clean energy goals (Hawaiian Electric 2021). KIUC (2023a) anticipates that Kaua'i will also require additional transmission to support future reliability needs and to mitigate outages associated with insufficient transmission capacity in its remote North Shore region.

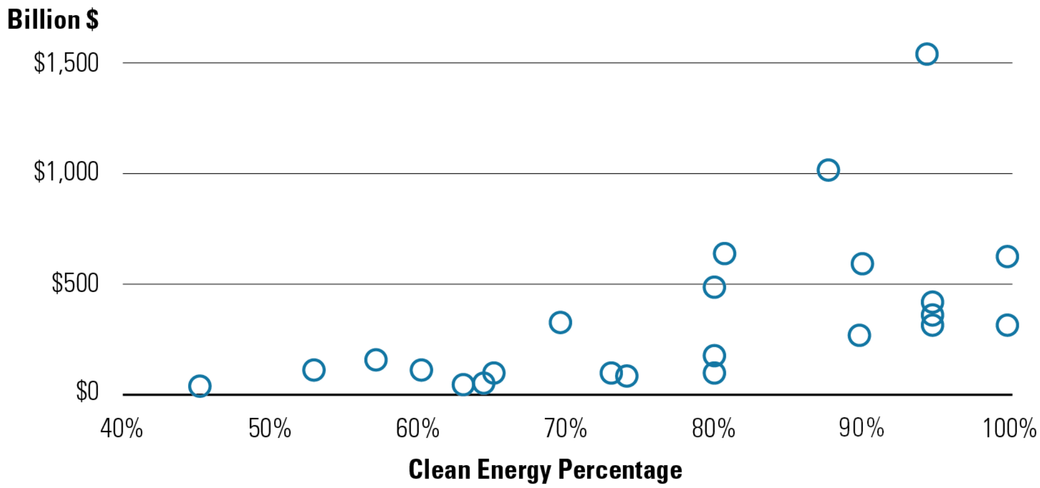
V.c. Generation and Demand Changes

New transmission will be needed to access many clean energy resources

Many reports surveyed cite access to clean energy resources for electricity production as a significant driver of transmission need. Numerous sources, including Brinkman et al. (2021), Bloom et al. (2020), Novacheck et al. (2021), Ardani et al. (2021), Cole et al. (2021), Clack et al. (2020b), FERC (2020), MISO (2022a), MISO and SPP (2022), Xu et al. (2021), and Pfeifenberger (2021), discuss the need for expanded transmission infrastructure at the national and international levels to take advantage of the diversity of generation resources.

Increasing the diversity of both resource fuel-type and resource geographic location improves the electric system's ability to produce affordable, reliable energy while increasing the operational flexibility and reliability of the grid. The reports reviewed also note other benefits of clean energy generation integration, such as lowered electricity prices and system costs, avoided climate damages, and air quality improvements for frontline communities.

Several studies cite a need for significant transmission expansion as clean energy penetration increases. Most of these studies, including NERC (2021), indicate that expanding transmission will especially improve VER integration. Transmission planning entities are developing long-term assessments of regional transmission upgrades, sometimes stretching 15 to 20 years into the future. These plans are motivated by shifts toward greater renewable energy generation amid fossil fuel generation retirements, changes in demand patterns, and a need to increase intra- and interregional capacity, especially as new generation may not be located near retiring generation or load centers. Building transmission across regions and transmission between regions enables the system to take advantage of the geographic and temporal diversity of energy generation, particularly from wind and solar resources, for which abundant production in one region can help compensate for low production in another in times of need. Figure V-6 shows growing transmission investments associated with increasing clean energy generation.



Source: Department of Energy (DOE 2022a), modified by author in June 2023.

Figure V-6. Summary of transmission investments estimated by several studies that enable differing levels of clean energy generation.

In many cases, renewable generation increases will require upgrades to transmission capacity, which can involve modifying existing lines in addition to or instead of new construction (ISO-NE 2022b). Clack et al. (2020b) demonstrate that expanding transmission infrastructure to access low-cost renewable energy is a reliable, cost-effective way to reduce emissions, increase consumer savings, and stimulate electric-sector job creation. The authors find that significant amounts of new high-capacity transmission will be required regardless of the cost of renewables. In contrast, Phadke et al. (2020) find that low-cost generation technologies can reduce the amount of interregional transmission needed to connect high-quality renewable resource areas to load regions, which are often distant from one another. The authors explain that improved technology can access lower-quality resources and storage sited closer to load (Phadke et al. 2020).

Multiple long-term transmission plans conducted by regional planning entities identify the need to move new renewable energy generation from remote or distant areas to load centers (CAISO 2022b; ERCOT 2022b-d; MISO 2022a; NYISO 2022a). Retiring fossil fuel generation often is located closer to population centers, but renewable generation often is located far from retiring generation facilities and therefore cannot rely on the same transmission infrastructure. ERCOT (2022b) notes that 60% of the planned inverter-based resource additions to ERCOT's system are located in West Texas, which is a significant distance from demand centers in the eastern portion of the state. MISO (2022a) describes similar challenges as some planned renewable generation in the Midwest lacks adequate connection to demand centers. Like ERCOT, MISO is considering HVDC options. Tranche 1 of MISO's LRTP also proposes 18 new 345 kV lines that improve system-wide reliability and enable greater renewable penetration while delivering greater benefits than costs (MISO 2022a).

National studies, such as Ardani et al. (2021), Bloom et al. (2020), and others, also find a need for significant transmission expansion with increasing clean energy penetration. In a decarbonization scenario targeting a 95% reduction in emissions on the U.S. electric grid from 2005 levels by 2035, Ardani et al. (2021) show that by 2050, transmission capacity expands by 60% (86,000 GW-mile [GW-mi])[44] relative to a reference scenario. Additionally, Cole et al. (2021) analyze scenarios of a wide range of power system futures and generally find that scenarios with higher levels of emission abatement correlate with higher levels of renewable generation deployment and increased levels of transmission development.

Clack et al. (2020b) find modeling scenarios with strong carbon-reduction policies result in approximately 140,000 GW-mi of new interstate transmission, whereas scenarios with weak carbon-reduction policies for cases with high solar and high wind generation deployment result in approximately 100,000 GW-mi and 70,000 GW-mi of new transmission, respectively. Clack et al. (2020b) also show that the amount of transmission capacity required for integration varies with the type of technology. Moving from weak to strong carbon cases under the high solar deployment case results in greater incremental transmission investment compared with moving from weak to strong carbon cases under the high wind generation deployment case. Presumably, this difference is because increased solar generation deployment in the Southeast requires additional transmission capacity to export excess solar energy production during the daytime and to import wind energy production at night.

Xu et al. (2021) investigate the renewable generation and transmission requirements needed to achieve 70% clean energy for the U.S. electric grid by 2030 by modeling different transmission designs. The authors model four distinct transmission designs that include AC only and combined AC and HVDC transmission upgrades. In all cases, AC capacity relative to current capacity increases from about 23% to 36%. The broader reach of the design with a new 16-line HVDC network connecting all three interconnections with no change in existing HVDC converter station capacity enables southeastern U.S. states to import power from elsewhere in the country. Regardless of transmission design, the authors find that certain U.S. transmission corridors require large capacity upgrades. These common upgrades, approximately 56 terawatt-miles (TW-mi), make up at least half of upgrades for each design. Regional upgrades common across all transmission designs are found in the Southeast, Midwest, and Texas. The most common interregional transmission needs are found between the Plains and Delta regions and between the Southeast and Florida. An HVDC network connecting the Eastern and Western Interconnection seam can also reduce the cost of resources required to meet clean energy goals. For example, the need for transmission upgrades in the Eastern Interconnection is reduced because the Western Interconnection exports more clean energy (primarily solar) to the Eastern Interconnection (Xu et al. 2021).

In a scenario with constrained carbon dioxide emissions (80% reduction in carbon emissions from 2005 levels in the United States and Mexico, and 92% reduction in Canada by 2050), Brinkman et al. (2021) find even more transmission is necessary because variable resource costs

[44] GW-mi is not a commonly used unit in the industry, but is the unit used by capacity expansion modeling results. For comparison, a 100-mile, 345 kV rated transmission line has an estimated carrying capacity of 860 MW, equivalent to 86 GW-mi (NRRI 1987). A 200-mi 500 kV line has a carrying capacity of 1,320 MW, equivalent to 264 GW-mi (NRRI 1987). *See* Table VI-2 for a comparison of carrying capacities and nominal voltage ratings for different length transmission lines.

are higher, forcing transmission buildout to more resource-rich regions farther from load centers. The authors note that their findings do not demonstrate that it is impossible to achieve renewable contribution levels or reliable future grids without extensive new transmission builds, but rather that those scenarios, if feasible, would come at a higher cost. In their modeling to estimate the system cost of electricity in a 100% renewable U.S. power system, Brown and Botterud (2020) conclude that transmission capacity expansion and better coordination between regions can reduce the cost of decarbonization by almost half compared with a case with no interstate or interregional transmission investments, reinforcing the idea that decarbonizing without increasing transmission will be more costly.

In a WECC assessment of the requirements to meet clean energy goals by 2040 within the Western Interconnection, Bailey (2022) emphasizes that transmission constraints are of significant concern at a 100% clean energy level and additional transmission investments should be considered early because new lines take many years to plan, site, approve, and build. Larson et al. (2021) argue that planning, siting, and construction of new lines should be a priority in the 2020s to meet the large need for new transmission projected for the 2030s.

CAISO's (2022b) *20-year Transmission Outlook* identifies specific 500 kV AC and HVDC lines, transformers, substations, and converter stations required to upgrade California's existing bulk transmission footprint and to deliver new offshore wind development, out-of-state wind resources, and solar generation. The recommended projects help to avoid overload and voltage collapse scenarios forecasted in CAISO's models. CAISO notes that given its interconnection queue length, transmission planners are facing obstacles to adding necessary resources to the grid.

Hildebrandt et al. (2021) identify a series of transmission system improvements to integrate the expected generation resources needed to meet the goals of California's Senate Bill 100 (California Legislature 2018), which sets a target that 100% of California's retail electricity be met by renewable and zero-carbon sources by 2045. Hildebrandt et al. (2021) estimate the cost of transmission investments to integrate renewable resources at $30.5 billion, comprising $10.74 billion in upgrades to the existing CAISO footprint, $8.11 billion for offshore wind integration, and $11.65 billion for out-of-state wind integration. The authors report that accommodating 4.7 GW of wind resources from Wyoming and 5.2 GW from New Mexico will require additional incremental transmission builds. Hildebrandt et al. (2021) also show the importance of addressing transmission infrastructure needs in California, stating that rapid increases in renewables are outpacing projections. For example, CAISO's 2020–2021 transmission plan is based on the addition of 1,000 MW per year of new resources, while the forthcoming 2022–2023 transmission plan is expected to be based on 4,000 MW per year.

Similarly, Simonson et al. (2021) note the high number of solar, wind, and storage projects in generation interconnection queues seeking to interconnect to the grid in Utah in the Mountain region, and the potential for additional future renewable resource development due to municipal and county renewable energy goals within the state. The study finds that anticipated renewable generation development, in combination with load growth, created the need for the Utah transmission system to accommodate between 1.7 and 2 GW of new resources by 2025, between 3.5 and 5.1 GW by 2030, and between 5.5 to 9 GW of new capacity by 2040. The authors note that transmission buildout in the state will not only serve to accommodate resource interconnection but is also necessary to reduce congestion and constraints on key paths.

In MISO's *Renewable Integration Impact Assessment*, Prabhakar et al. (2021) conclude that renewable penetration beyond 50% in the MISO region can be achieved with coordinated action. The assessment identifies new and changing risks and system needs, including insufficient transmission capacity. Furthermore, transmission infrastructure investments, especially the higher voltage lines, increase with increasing renewable penetration. Expansion of new transmission lines rated 161 kV and below is highest at the 30% renewable generation level at 1,700 circuit-miles, decreasing to 500 circuit-miles at 50% renewable generation. On the other hand, expansion of new transmission lines rated 230 kV and higher ranges from 700 circuit-miles at 20% renewable generation to 6,000 circuit-miles at 50% renewable generation. In addition, new HVDC lines were identified at 30% renewable generation levels and higher.

Dimanchev et al. (2020) note that meeting existing state climate policy targets in New York and New England will likely require the nearly complete decarbonization of electricity generation. To that end, consideration is being given to expanding imports of hydropower from neighboring Québec, Canada. According to the study, in a low-carbon future, it is optimal to shift the utilization of the existing hydropower and transmission assets away from facilitating one-way export of electricity from Canada to the United States and toward a two-way trading of electricity to balance intermittent U.S. wind and solar generation (Dimanchev et al. 2020). The authors find that doing so can reduce power system costs by 5%–6% depending on the level of decarbonization. The cost-optimal use of Canadian hydropower is as a complement, rather than as a substitute, to deploying low-carbon technologies in the United States. Expanding transmission capacity enables greater utilization of existing hydropower reservoirs as a balancing resource, which facilitates a greater and more efficient use of wind and solar energy.

Jones et al. (2020) similarly note in a regional analysis conducted for a Massachusetts study that Canadian hydropower is an essential element of regional balancing. In their study, bidirectional flow of electricity enabled the Québec hydropower system to transition into the role of a "battery," storing excess wind and solar generation for the New England region. The use of a hydropower system as storage depends on the timing of renewable production and demand on both sides of the U.S.-Canada border (Jones et al. 2020). Total net-imports into Massachusetts from Québec declined after 2035 in the analysis. The study estimates that an additional 4.1 to 7.1 GW of new transmisison capacity between Québec and New England would be required.

In the Southeast, utility planning and state regulatory processes have also highlighted the need for additional transmission to accommodate a shift in the generation fleet and to meet decarbonization targets. Duke Energy's *2022 Carbon Plan*, for example, has identified the need for significant transmission investment on an aggressive timeline to accommodate incremental generation resource additions and coal plant retirements necessary to meet carbon emission reductions and carbon neutrality targets established by North Carolina Session Law 2021-165 (Duke Energy 2022). The North Carolina Utilities Commission's *Carbon Plan* order urges Duke—in light of the magnitude of potential future transmission expansion—to be vigilant in its participation in the Southeast Regional Transmission Planning. and coordination with PJM to explore all possible efficiencies (NCUC 2022).

In Alaska, Denholm et al. (2022b) assesses the techno-economic feasibility of an 80% renewable portfolio standard within the Railbelt region. The study finds that additional transmission will likely be required to connect new renewable resources necessary to reach an 80% renewable portfolio standard. Additionally, all scenarios considered identify the need to significantly upgrade the Alaska Intertie interconnecting utilities in the Railbelt's northern footprint with those located south of the intertie. Allen et al. (2016) describes solutions for integrating clean energy resources in rural areas outside of Alaska's Railbelt region, which have historically been powered by localized diesel-fired generation, including additional transmission interconnection between rural utilities where feasible, among other solutions. The report notes, however, that in instances where geography and distance prevent interconnection feasibility, the interconnection of variable renewable energy in rural villages may require a suite of alternative transmission solutions, including flexible load and storage, to capture any excess generation and prevent curtailment.

In Hawaii, Hawaiian Electric (2023a) finds that transmission network expansion is critical for Hawaii island, Oahu, Maui, Lanai, and Molokai to be able to integrate sufficient renewable resources required for the state to reach its 100% renewable by 2045 renewable portfolio standard target. In addition, utility service providers continue to work with communities and landowners to identify renewable energy zones that are prime for renewable resource development but may be far from existing transmission infrastructure or require robust transmission upgrades to accommodate the generator interconnection (Hawaiian Electric 2023a). Hawaiian Electric (2023b) also anticipates reliability concerns due to high levels of inverter-based renewables integration, noting future systems with increased inverter-based resources will experience lower physical inertia and more complex dynamics during system events. To address potential concerns, Hawaiian Electric (2023b) finds that grid-forming inverter-based resource[45] integration is a critical component to reduce the adverse impacts (e.g., load shedding) of incorporating higher levels of renewable generation. Hawaiian Electric (2023a) notes promising performance of grid-forming resources on the island of Kaua'i.

Reduced curtailment of available economic generation resources can be achieved with additional transmission

Various reports reviewed as part of this literature review, including Brown and Botterud (2020), Clack et al. (2020b), Xu et al. (2021), Bailey (2022), and FERC (2020), cite transmission expansion as an effective means of avoiding or reducing generation curtailment. Several reports maintain that curtailment is caused primarily by generation oversupply and transmission constraints.

[45] Historically, inverters were not able to operate independently of the power grid they were connected to and could not provide essential services to bring the power grid back online following a disturbance. These inverters are referred to as "grid-following," given their dependence on the grid. "Grid-forming" inverters can operate independently and provide essential services to help the grid ride through a disturbance. See Lin, et al. (2020) for more information about grid-forming, inverter-based resources.

Curtailment is often cited as a concern, as it may challenge objectives to efficiently integrate renewables to reach electric-sector decarbonization goals, to realize the full benefits of renewable generation investments, and to achieve further pollution reduction. Xu et al. (2021) note, however, that some amount of curtailment is inevitable—even with a perfect transmission network—because of the patterns of solar and wind availability.

In a study examining the potential economic value of increasing power transfers between the Eastern Interconnection and Western Interconnection, Bloom et al. (2020) model four different transmission designs that include HVDC transmission expansion co-optimized with generation investments and AC transmission investments. The authors report that the curtailment of renewable generation ranges from 11% to 15%, with congestion on AC transmission lines as the main driver. They note, however, that understanding the tradeoffs among curtailment, transmission, and other options requires additional analysis. Pfeifenberger (2021) quantifies curtailment reductions, estimating that for grids with 10%–60% renewable generation, regional diversification through the transmission grid results in curtailment reductions ranging from 45% to 90%.

Ardani et al. (2021) further state that curtailed solar and wind represent low-cost, zero-carbon power that can be used to supply new demand or produce low-carbon fuel. Using this curtailed energy, however, will require co-locating solar resources and low-carbon fuel production, developing adequate transmission connections, or identifying new demand resources that can make economic use of the variable curtailed solar. The report also notes that curtailment occurring during the operation of combustion turbines fueled by renewable energy sources is an indication of transmission congestion, which demonstrates the critical role of transmission in achieving a least-cost mix of resources.

Clack et al. (2020b) find that expanding continental-scale transmission across the eastern and western United States, as well as increasing ties to ERCOT and Canada, can also help reduce curtailment through greater geographic diversity of resources. Additionally, the authors note that electrification could help reduce curtailment if resource dispatch and wholesale electricity markets are coordinated.

Prabhakar et al. (2021) demonstrate transmission solutions substantially decrease wind energy curtailments at 40%–50% renewable penetration levels in the Midwest and Delta regions. The report notes that because transmission solutions have a lower effect on curtailment reductions at 50% renewable penetration level, transmission solutions have potentially diminishing returns at higher penetration scenarios.

Generation curtailments that are due to transmission constraints can also have reliability impacts. Goggin and Zimmerman (2023) and Massie and Toth (2023) suggest that additional interregional transmission capacity could have mitigated Winter Storm Elliott's impacts in the Southeast. Massie and Toth (2023) note that although wind generation in the Plains, Midwest, and Mid-Atlantic remained strong and consistent throughout Winter Storm Elliott, transmission limitations led to significant curtailment. Approximately 3 GW of wind curtailments occurred in SPP while TVA customers in the Southeast faced blackouts, and Massie and Toth (2023) suggest that additional transmission could have reduced these blackouts for TVA customers.

Offshore wind potential is driving transmission needs, but offshore transmission networks require specific planning considerations to meet those needs

Offshore wind is poised to play a significant role in the country's decarbonization as it expands beyond the existing 42 MW of operational offshore wind capacity. As of May 2022, the project development and operational pipeline of wind energy has increased to 40,000 MW of planned offshore wind capacity (Musial et al. 2022). Shields et al. (2022) note that meeting the federal goal of 30 GW of offshore wind energy by 2030 could require 2,100 turbines and over 11,000 kilometers (km) of transmission cables.

Several aspects of offshore wind transmission can help unlock the country's significant wind energy potential. Offshore transmission planning is siloed (Pfeifenberger et al. 2023; Bothwell et al. 2021) and leads to transmission development on a piecemeal basis, resulting in inefficient outcomes. That is, transmission planning that accommodates for future offshore wind capacity installation rather than planning on a project-by-project basis can ensure a networked, more cost-effective solution in the long run. Additionally, interregional transmission coordination (Pfeifenberger et al. 2023; Douville et al. 2023; Bothwell et al. 2021) can be stymied by disparate state policies, as well as cost allocation and permitting issues. Technology development, integration, and standardization of HVDC transmission can unlock solutions that reduce environmental impacts and are more cost-effective (Pfeifenberger et al. 2023), while helping to advance the technological readiness of floating offshore wind (Douville et al. 2023). Finally, transmission infrastructure along the nation's coasts is insufficient to accommodate utility-scale injection of offshore wind. Shared offshore transmission will need to be developed and connected to the onshore system, which will require further analysis of topologies and their associated costs, benefits, and siting options (DOE 2023a).

Several studies discuss the unique transmission challenges associated with offshore wind integration in bringing generated power through the ocean to onshore terminals where it will be delivered to load. Looking at examples on the Atlantic is relevant, given that most of the 30 GW of offshore wind energy by 2030 is projected to be developed along the Atlantic Seaboard (Bothwell et al. 2021). Pfeifenberger et al. (2020a; 2020b) evaluate offshore transmission planning approaches for New England and New York, respectively. They find that an offshore grid designed and built with the capability of a networked system will provide more benefits and will better facilitate the integration of offshore wind resources compared with each offshore wind resource connecting to the onshore grid through a dedicated generator lead line. Pfeifenberger et al. (2020a; 2020b) find that designing and building the offshore grid with the capability of a networked system will improve reliability and reduce curtailments when transmission outages occur.

NYISO (2022a) acknowledges that the pace of renewable energy growth requires an increase in transmission development or there will be significant transmission constraints in New York. The most significant increase in future renewable generation curtailments will be experienced by offshore wind projects connected to Long Island where there is inadequate transmission capacity. The Long Island Authority Board of Trustees identified a transmission need for offshore wind to meet state climate goals (NYISO 2022a). In addition, the New York State Public Service Commission issued an order stating that offshore wind goals are driving the need for additional transmission facilities to deliver at least 3,000 MW of offshore wind output from Long Island. Additional offshore wind injections will require local onshore transmission and distribution system upgrades on Long Island. Without further investment in transmission, Long Island could experience persistent and significant limitations to deliver renewable power to customers (NYISO 2022a).

ISO-NE, like other transmission planning authorities on the Atlantic coast, is expecting additions of significant New England offshore wind generation in the coming years. ISO-NE discusses a tradeoff between smaller and larger offshore wind interconnections (ISO-NE 2022b). For example, smaller interconnections involve lower transmission upgrade costs but higher generator lead costs, along with a greater number of HVDC converters and offshore connections. Conversely, larger interconnections are the opposite, with lower numbers of converters and connections but higher transmission upgrade costs (ISO-NE 2022b).

Pfeifenberger et al. (2020a) indicate that New England had contracted for over 3,000 MW of offshore wind generation at time of publication. A subsequent 3,600 MW of offshore wind generation could still be developed under the status quo, with each developer constructing a generator tie-line to an onshore point of interconnection. However, this existing approach is likely to require substantial onshore system upgrades far sooner than assumed. Selected projects connecting to the transmission system on Cape Cod, Massachusetts, already face up to $787 million in onshore transmission upgrades. Continuing this approach in the next set of generation procurements could lead to an additional $1.7 billion in onshore upgrades (Pfeifenberger et al. 2020a). This conclusion emphasizes the possible need for new infrastructure and coordinated planning.

ISO-NE's *First Cape Cod Resource Integration Study* (2021) identifies the transmission upgrades necessary to enable the interconnection of proposed new offshore wind resources to Cape Cod. This study finds that a new 345 kV line would enable another 1,200 MW of offshore wind generation to interconnect. This system upgrade would supplement the already-estimated 1,600 MW of proposed Cape Code offshore wind generation that has completed its interconnection studies. This 2,800 MW of total new offshore wind generation demonstrates the significant economic potential of offshore wind generation. At the same time, it is clear that the anticipated interconnections for offshore wind generation are likely to be much higher than assumed when planning the area's current grid infrastructure. In response to the growing interest in offshore wind generation, ISO-NE has developed a process for identifying common infrastructure needs and minimizing potential interconnection queue backlog resulting from the influx of proposed offshore wind generation.

Pursuing proactive, coordinated transmission planning solutions to offshore wind integration can reduce onshore grid upgrade costs, increase reliability, and reinforce existing regional onshore grids (Pfeifenberger et al. 2023). Research by Pfeifenberger et al. (2023) and Burke et al. (2020) also notes that long-term planning can improve efficiency and reduce environmental impacts by reducing the number of necessary points of interconnection, miles of transmission cables, and other physical infrastructure.

Given the complexities of integrating offshore wind along the Atlantic coast, the Department initiated the Atlantic Offshore Wind Transmission Study in 2021 to analyze how different coordinated transmission solutions enable offshore wind energy deployment along the U.S. Atlantic Coast (*see* accompanying text box). Preliminary analysis indicates that connecting large volumes of offshore wind along the Atlantic Coast over the next several decades provides a unique opportunity to use interregional transmission links to reduce electricity production costs and bolster reliability and resilience onshore.

DOE Work on Offshore Wind Transmission

DOE is in the process of completing the Atlantic and West Coast Offshore Wind Transmission Studies. The studies evaluate multiple pathways to reach offshore wind goals through coordinated transmission solutions along the U.S. Atlantic and Pacific coasts under various combinations of electricity supply and demand while supporting grid reliability and resilience and ocean co-use. Researchers from the National Renewable Energy Laboratory and the Pacific Northwest National Laboratory are conducting these studies by creating multiple scenarios of interstate, interregional transmission topologies between 2030 and 2050.

National Renewable Energy Laboratory, Atlantic Offshore Wind Transmission Study, https://www.nrel.gov/wind/atlantic-offshore-wind-transmission-study.html.

Working in close coordination with the Atlantic Offshore Wind Transmission Study, DOE and the U.S. Department of the Interior published an interim draft of *An Action Plan for Offshore Wind Transmission Development in the U.S. Atlantic Region* in September 2023. Key recommendations from the Action Plan involve improved environmental review and permitting frameworks, strong state leadership, empowerment of permitting agencies, thoughtful cost allocation practices, and consideration of NIETCs. Examples of Action Plan recommendations relevant to assessing and addressing transmission need include evaluating point-of-interconnection capacities and locations, clarifying NERC reliability standards around offshore transmission, considering interregional transfer capability minimums, and collaborating on federal-state aligned offshore transmission siting (DOE 2023b).

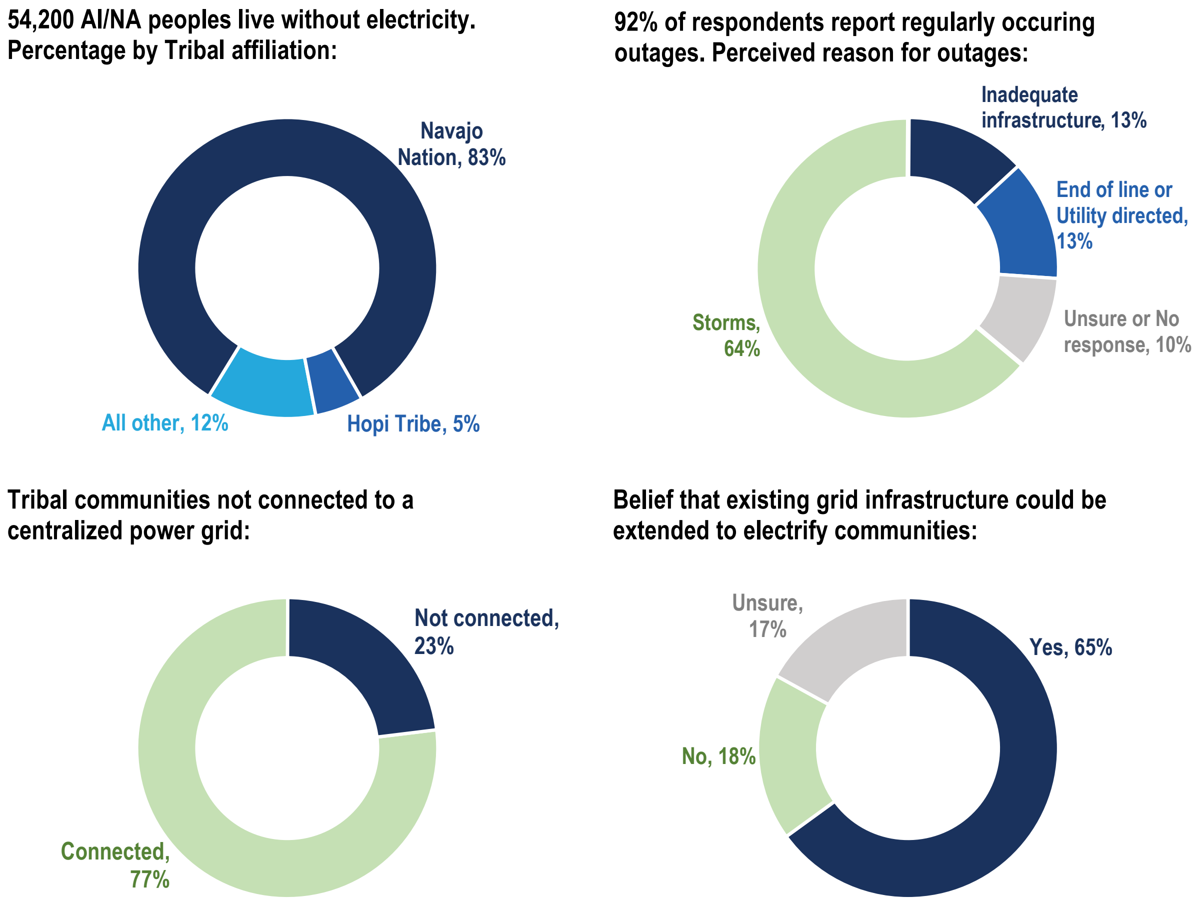
Given the topography of the U.S. Pacific coast, planners and researchers are looking at the development of floating offshore wind along the California and Northwest coasts. Grid planners in California and Oregon are investigating ways to integrate large offshore wind generators (CAISO 2022b; NorthernGrid 2023). Evolved Energy Research (2021) considers the complexities of integrating offshore wind along the Pacific Coast. The authors note that a substantial portion of investment in offshore wind in the Northwest is needed to meet both Oregon's current 2050 economy-wide target of 80% emissions reductions below 1990 levels and to enable exports of low-cost, high-capacity-factor clean electricity to other Western states (Evolved Energy Research 2021). The 20 GW of offshore wind projected to be built over 15 years would require a rapid scale-up of new supply chains and production capacity. A regionally integrated power grid is critical to enabling Oregon to take advantage of out-of-state clean energy resources, export power to other states, and efficiently plan for grid reliability. Regional grid integration will also be key to efficient decarbonization throughout the West.

Tribal lands have unique energy and transmission needs

Indian Tribes have expressed a significant need and interest in developing their own energy resources, implementing energy efficiency and renewable energy technologies, stabilizing energy costs, and spurring local economic development, especially when jobs can be provided to Tribal members. Lack of tribe-specific data has historically prevented quantifying the current energy state in Indian Country and hampers justifying additional resources, however (Johns et al. 2022).

The Department is currently conducting a survey of Tribal access to reliable electricity as directed by the Fiscal Year 2021 Consolidated Appropriations Act. Preliminary survey results suggest that over 54,000 American Indian and Alaska Native (AI/NA) peoples do not have access to electricity today, most notably the Navajo Nation and Hopi Tribe (Johns et al. 2022). Among those who do have access to electricity, respondents overwhelmingly (92%) reported regular electricity outages, often because of inadequate infrastructure or because they are serviced by a single power line that lacks redundancy. Nearly a quarter (23%) of all survey respondents do not have access to a centralized power grid, but many of those do have access to electricity via a local microgrid. The large majority (65%) of respondents believe that existing grid infrastructure could be extended to Tribal communities to provide more reliable electricity. Figure V-7 summarizes these preliminary findings (Johns et al. 2022).

Indian Country contains vast untapped energy resources. While a wide variety of energy resources exist on Tribal lands, increasing vulnerabilities due to climate change have resulted in a rising demand for clean energy generation (Jones et al. 2022). Renewable energy technologies provide opportunities for diversification, energy independence, environmental sustainability, and new revenue streams for Native American Tribes, Alaska Native villages, and Alaska Native corporations (Milbrandt, Heimiller, and Schwabe 2018). Many Tribal lands are located in areas that have abundant renewable energy, such as wind, solar, and biomass. Over 9% of the nationally available renewable energy resource is found within 10 miles of federally recognized Tribal lands (Brooks 2022). Transmission is key in accessing these potential generation resources.



Source: Department of Energy (Johns et al. 2022).

Note: "AI/NA" stands for American Indian and Alaska Native.

Figure V-7. Preliminary survey results demonstrating lack of reliable access to centralized electricity on Tribal lands.

In Milbrandt, Heimiller, and Schwabe (2018), the authors estimate the technical and economic potential for renewable energy development on Tribal lands to support American Indian Tribes and Alaska Natives in decision-making as they evaluate technologies, potential scales of development, and economic viability. The resources analyzed include wind, solar photovoltaic and concentrating solar power systems, woody biomass, biogas, geothermal, and hydropower. The analysis shows that the utility-scale technical potential of these resources on Tribal lands is approximately 6.5% of the total national technical potential. By comparison, federally recognized Tribal lands make up approximately 5.8% of the contiguous U.S. land area (Milbrandt, Heimiller, and Schwabe 2018).

Milbrandt, Heimiller, and Schwabe (2018) find the economic potential[46] for Tribal land-based wind exceeds 1 GW, which could produce more than 3 TW-hour (h) of electricity generation annually. For utility-scale photovoltaic systems, there is more than 61 GW of economic potential, which could produce nearly 116 TWh of electricity generation annually. There is potential for distributed wind and solar in almost all Tribal areas; however, in low-resource areas the resulting levelized cost of energy is high and might not be competitive with grid electricity prices. Broadly, Tribal lands in the western United States and the Plains regions contain high-quality resource potential for wind, even at lower turbine hub heights. In the eastern and southeastern United States, wind opportunities are more limited. Increased solar resource availability makes distributed solar photovoltaic systems more productive for Tribes in the southern United States. Other renewable technologies did not show positive economic potential on Tribal lands based on the set of assumptions used in Milbrandt, Heimiller, and Schwabe (2018).

Resources that did not show economic potential in Milbrandt, Heimiller, and Schwabe (2018) could be revisited as the relative costs of renewable energy technology and market prices change. This constantly changing cost profile is particularly important in determining the relative value of renewable energy compared with other replacement sources of energy (Milbrandt, Heimiller, and Schwabe 2018). Future improvements to economic potential assessments on Tribal lands include incorporating both in-region and out-of-region transmission costs and other policy drivers such as energy independence, reliability, environmental benefits, renewable portfolio standards, and any sensitivities to tax-oriented policies.

Access to the transmission system is required to bring the economically viable generation resources to market. Where some Tribal lands are well covered by the transmission system, some have limited or no access to high-voltage lines. The Department has funded the Geospatial Energy Mapper to locate potential areas of low-carbon energy development. This tool also includes an interactive map of the existing transmission system and Tribal lands to see where overlaps do and do not exist (*see* accompanying text box). Figure V-8 shows the transmission system near the Tohono O'odham and the Houma Tribal lands—two areas with very different transmission coverage—using the Geospatial Energy Mapper tool. Similar maps could be made using the tool for anywhere in the contiguous United States.

In addition to transmission access, there are significant financial, infrastructure, and human capacity barriers that hinder Tribal energy development. Federal Indian law and jurisdictional uncertainties and complexities limit private investment and impede energy development on Tribal lands. Complicated Federal application processes and funding gaps limit access by American Indian and Alaska Native communities (Jones et al. 2022).

[46] Whereas *technical potential* defines the amount of energy of a particular resource that could be converted into electricity given current technologies, the *economic potential* defines the amount that is financially viable to convert given technology costs and projected project revenue.

DOE Work on Mapping Energy Resources

The Department has 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 clean power generation and potential energy transmission corridors in the United States.

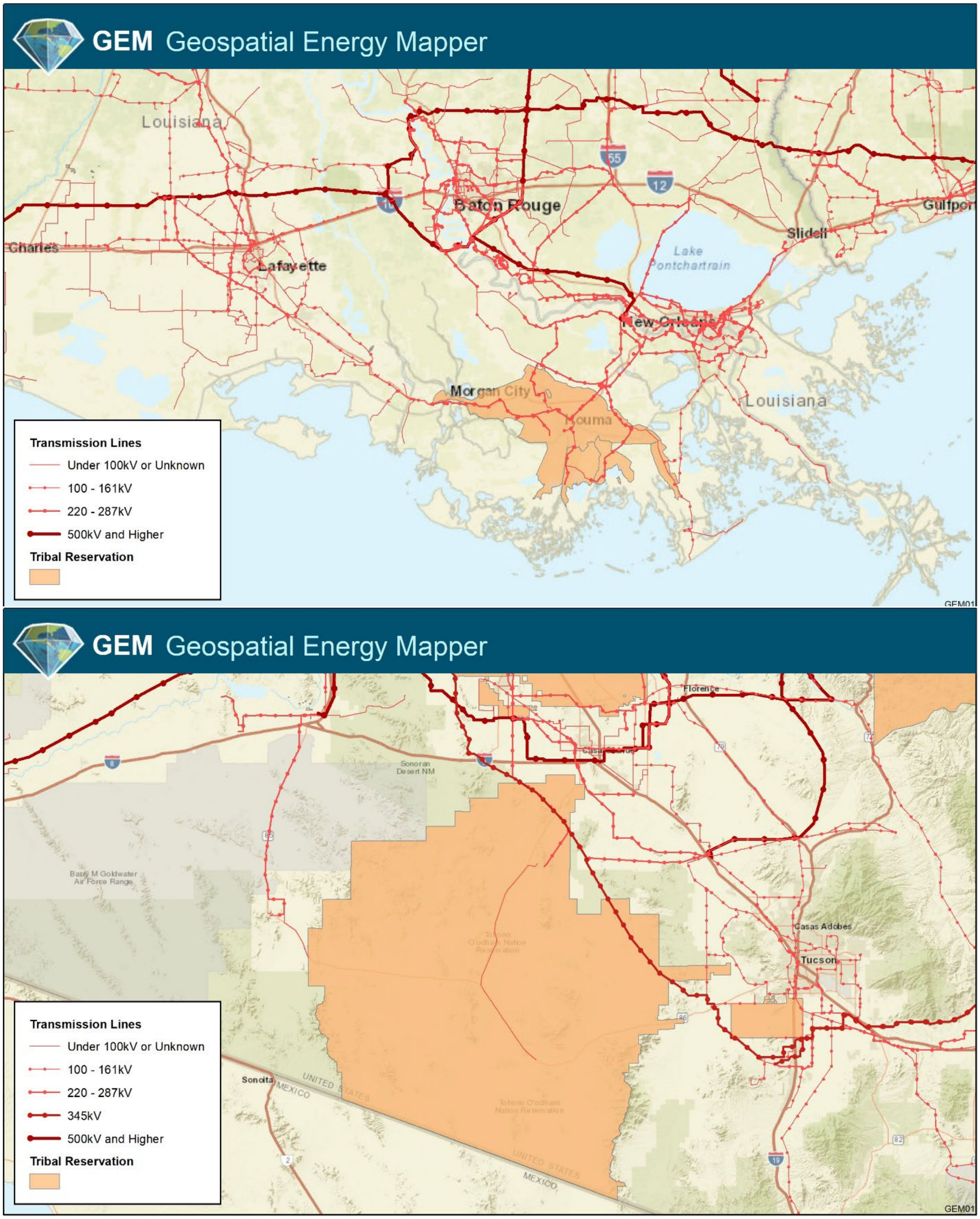
Argonne National Laboratory, Geospatial Energy Mapper (GEM), https://gem.anl.gov/.

Load growth will require more transmission

Load growth necessitates additional transmission capacity to transfer more power to consumers. In instances when load growth occurs in existing load centers, capacity expansion of existing transmission infrastructure through line upgrades or rebuilds, or through advanced transmission technologies, can help meet electricity needs. In cases where load growth may occur in areas far from existing load centers, potentially due to growth in emerging industries, new transmission wires may be required to deliver electricity. System operators are preparing for significant load growth in the coming decade, including in regions where important advances in energy efficiency resulted in near historic flat electricity demand (Gledhill 2021; ERCOT 2021b; PJM 2023a).

Several studies identify emerging industries with high electricity use—such as data centers, chemical production, hydrogen production, and direct air capture—and electrification of end-use devices as another major driver of transmission investments. Electrifying technologies and systems that currently run on fossil fuel sources are important in enabling economy-wide decarbonization to mitigate the impacts of climate change and improving local air quality that impacts human health, particularly for frontline communities.

ISO-NE's *Future Grid Reliability Scenarios* study (ISO-NE 2022a) notes that, in addition to changes in electricity supply, regional goals and legislation regarding heating and transportation will also change the way electricity is used throughout New England over the next decade and beyond. Heating and transportation will become further electrified. Policy initiatives to replace building heating systems currently powered by wood, oil, propane, or natural gas to electricity will have a significant impact on the power grid. Replacing these building heating systems with electric-powered air-source or ground-source heat pumps will significantly increase the total demand on the New England grid. The replacement of gas and diesel-powered vehicles with electric vehicles will also increase overall system demand. Heating and electrification demand envisioned by one of ISO-NE's future scenarios is an exponential increase from current trends. In addition to the overall increase in demand, daily electrical system demand patterns will also change.



Source: Created by Jim Kuiper at Argonne National Laboratory using the Geospatial Energy Mapper tool (2022).

Figure V-8. Overlap of the existing transmission system with the Houma (top) and Tohono O'odham (bottom) Tribal lands.

An increase in electrification could present reliability risks without proactive transmission planning (NYISO 2022b; PJM 2022). NYISO's *Reliability Needs Assessment* observes that New York reliability risks are anticipated to increase during winter months by mid-2030 as the grid is becoming winter-peaking due to space heating and transportation electrification (NYISO 2022b). PJM notes that demand growth in the winter is anticipated to more than double compared with summer demand growth due to increased electrification, causing a shift in seasonal and hourly risk in the winter (PJM 2022). Some major metropolitan areas are anticipated to experience significant load growth caused by shifts in local decarbonization policies that will impact the transmission and distribution networks. In New York City, for example, reliability margins are already at risk due to limited generation and transmission, while peak demand is expected to rise significantly due to commercial and residential growth (NYISO 2022b). Because of New York City's narrow reliability margins, it is possible that increased demand, significant delays in projects in Champlain Hudson Power Express development, or additional generator deactivations could all create deficiencies (NYISO 2022b).

Brinkman et al. (2021) simulate a scenario representing the electrification of heating, transportation, and other end-use energy demands in North America, such that electricity loads in 2050 are nearly double those in 2020. The result is significantly more transmission investments, with the greatest increase in investments at the intranational level. Under this scenario, transmission expansion within the contiguous United States is approximately 195 GW, over three times the business-as-usual scenario. Expansion between the United States and Mexico is approximately 8 GW and between the United States and Canada is approximately 20 GW.

FERC (2020) similarly reports on Brattle Group estimates that increased future electrification efforts will stimulate substantially more transmission investment compared with historical levels. The Brattle Group study quantifies these transmission needs, finding that the United States will need an average transmission investment of $3–$7 billion per year through 2030 due to electrification, in addition to maintenance and renewable integration investments.

Clack et al. (2021) points out that investments in the distribution system, and not just the transmission system, will be crucial in high electrification futures. In Clack et al. (2021), the largest share of cost in 2050 is distribution system investments, which are required to address system needs due to economy-wide electrification. In Hawaii, Hawaiian Electric (2023a) finds that new housing and electrification of load required to meet statewide housing and decarbonization goals in Hawaii may require modernization of the distribution system.

V.d. Alternative Transmission Solutions

Alternative transmission solutions can be deployed on the existing grid to increase transmission capacity, improve operational flexibility, and manage congestion and curtailment. Alternative transmission solutions like energy storage; DERs; advanced transmission technologies, including GETs and advanced conductors and cables; and microgrids are example technologies that can serve some of the same purposes as traditional transmission solutions, but these technologies are unlikely to meet the full scope of national transmission need on their own and do not obviate the need for new transmission infrastructure.

Strategic planning to site storage and generation close to load centers could also help mitigate the need for traditional transmission solutions. For example, DERs could help meet demand locally. Demand response is another technology with the potential to limit electricity demand when transmission is constrained. Implementing these generation- and demand-based solutions requires careful planning from utilities, state, and local officials to ensure resource adequacy and minimize risks but can provide significant value that outweighs costs when properly deployed. These alternative transmission solutions are discussed in more detail below.

Energy storage can aid the transmission system by balancing generation and load

Energy storage can serve as a grid asset to support higher degrees of variable energy on the system by shifting load across hours or days, smoothing seasonal peaks, and providing grid services. Prabhakar et al. (2021) find that pairing storage with renewables and transmission helps optimize grid operations in the Midwest and Delta regions. Without adequate transmission capacity, however, storage might not contribute sufficiently to achieving penetration targets. Similarly, Kemp et al. (2023) find that hybrid variable renewable energy-plus-storage plants can help reduce the need for transmission when sited near congested load centers, particularly when hybrid plant characteristics allow for the ability to charge from the grid and include storage technology with lower degradation costs.

In their storage sensitivity modeling, Prabhakar et al. (2021) indicate that even with large additions of storage to the MISO system, there is a limited change to transmission needs. More specifically, their modeling shows that beyond an incremental 12.1 GW of 6-hour storage at 40% renewable penetration, there is little change to transmission needs. In contrast, Bailey (2022) finds that adding battery storage resources can help offset the need for new transmission expansion in integrating renewables onto the grid.

Furthermore, Clack et al. (2020b) demonstrate that storage complements transmission by increasing the utilization of transmission lines. Jorgenson et al. (2022) also find that storage increases utilization of some transmission lines, as demonstrated by reductions in observed congestion, while reducing the congestion observed on other lines. Exactly how storage impacts nearby transmission by increasing or decreasing usage depends on the local conditions.

For instance, in New England, large quantities of new energy storage, primarily batteries, could be used as a solution to maintain grid reliability in a renewable-dominant landscape (ISO-NE 2022a). The ISO-NE (2022a) analysis finds that modeling storage with the objective of price arbitrage does not fully address the needs of the overall future power grid. Current reliability models may not be able to capture long dispatch periods and the reserve services that storage is able to provide, which will become increasingly important with larger VER penetration.

Allen et al. (2016) finds that thermal and battery storage have the potential to facilitate efficient renewable energy integration into rural Alaskan systems. In the absence of sufficient transmission interconnection, certain rural utilities have found storage able to provide a buffer for variable wind resource integration on system frequency and voltage levels. In Alaska's

Railbelt region, AEA and EPS (2017) find that battery storage deployment near Anchorage would help alleviate short-term overloads in the event of a Kenai Intertie transmission outage. The report notes that storage dispatch would provide time for generators to the north of the intertie to redispatch following a contingency event as well as reduce or eliminate the need for load shedding.

High penetrations of distributed energy resources can shift regional transmission needs

Clack et al. (2020a; 2020b; 2021) and other studies comment on the role of DERs[47] in a clean electricity system. Clack et al. (2020a) use a model that allows for the incorporation of a detailed representation of the distribution system and disaggregation of DER technologies, providing insights into the interface of the distribution and transmission systems. Their model enables comparisons between scenarios with a traditional planning approach augmented with DER co-optimization and scenarios that exclude DER co-optimization.

Clack et al. (2020a) also evaluate the potential value of DERs in lowering costs across the electricity system and promoting clean electricity goals. The study models four scenarios—a business-as-usual scenario with and without DER co-optimization and a clean energy standard scenario also with and without DER co-optimization. The authors find that transmission expands at a similar rate in all scenarios until 2035. In the clean energy standard scenarios, transmission expands rapidly after 2035, when significant changes in generation resource mix required to meet clean energy goals start to occur. Additionally, the study finds that DER co-optimization results in key geographic differences in the location of transmission builds. Compared with scenarios without DER co-optimization, scenarios with DER co-optimization require higher transmission buildout in the states in the Southeast to help integrate VERs. A similar trend, although to a lesser extent, occurs in the states in the Southwest that have higher solar generation. States in the northeastern regions require a higher buildout of transmission in scenarios without DER co-optimization to support utility-scale generation developed in those scenarios. In general, total transmission expansion is similar in the two business-as-usual scenarios. In the clean energy standard scenarios, total transmission expansion is slightly higher in the scenario with DER co-optimization. Incorporating DER co-optimization results in 85,000 GW-mi of new transmission builds, compared with 75,000 GW-mi without DER co-optimization. The study notes that the model does not simply replace transmission with DER, but rather removes transmission that is no longer economical and builds transmission in areas where it is more economical and supports grid decarbonization.

Investments in the distribution system are also crucial. Co-optimizing distribution system improvements with utility-scale generation contributes to significant reductions in distribution system costs. Co-optimizing the expansion of the distribution grid and development of DERs reduces total resource costs—mostly distribution system costs—by $109 billion by 2030 and by

[47] While each study referenced here may have slightly different definitions, a *distributed energy resource* is defined here as any electricity generation resource connected to distribution system facilities with a nominal rating of less than 100 kV.

$515 billion by 2050 nationwide, compared with a scenario that considers only utility-scale solar generation (Clack et al. 2021).

Clack et al. (2021) process a scenario with utility-scale and distribution system co-optimization in which DERs can grow to meet net-zero emissions in the U.S. economy by 2050. They find that all states except Montana and Oregon significantly increase interstate transmission capacity. The largest new transmission buildout is in the northeastern United States, whereas the Western Interconnection has lower buildout. Although transmission buildouts are still required, Ardani et al. (2021) demonstrate that because DERs can provide the same services as utility-scale solar generation, they offset the need for generation and transmission resources to maintain resource adequacy.

Hawaiian Electric (2023a) finds that alternative transmission solutions, including DERs, can cost effectively manage the buildout of new transmission required to meet clean energy targets on Hawaii island, Oahu, Maui, Lanai, and Molokai. Forecasted deployment of DERs, however, will require an increase in hosting capacity in some areas, particularly in the longer term. The study also finds the need to address system stability risks created by increased DER integration, such as momentary cessation.

Grid-enhancing technologies can improve the operational efficiency of existing transmission systems

GETs include a suite of solutions capable of managing transmission congestion and increasing line utilization rates by expanding existing transmission system capacity and improving operational efficiencies. GETs generally fall under software and hardware-based solution categories, which can be deployed to improve transmission system operations (DOE 2020b). Software solutions generally serve to enhance control and protection systems, advanced optical sensing and metering tools, real-time contingency analysis tools, and artificial intelligence-assisted operator decision-making processes. Hardware solutions typically serve to improve physical assets and the infrastructure responsible for carrying, converting, or controlling electricity.

GETs include dynamic line ratings (DLRs), power flow controllers (PFCs), dynamic transformer ratings, and topology optimization, among others (DOE 2022b).[48] Beyond congestion relief and increasing line utilization rates, GETs provide several system benefits, including situational awareness to enable safer real-time operations, asset deferral while longer-term solutions are implemented, increased grid resilience, and asset health monitoring (DOE 2022b).

GETs deployment can improve the reliability of the existing transmission system and can do so more economically than traditional transmission expansion in certain scenarios because GETs deployment often involves lower capital costs compared with new transmission line construction (DOE 2022b). GETs deployment can also complement traditional transmission expansion by reducing or avoiding impacts due to outages required for new transmission upgrades and new transmission line interconnection (Tsuchida et al. 2023).

[48]Energy storage is also sometimes identified as a GET, although it is discussed separately in this Needs Study.

DLRs use sensing devices and algorithms to collect real-time weather data and/or other information on ambient conditions that affect the operation of a transmission line and calculate the ampacity[49] of a conductor more accurately. More accurate consideration of ambient conditions can enable operators to model the true thermal limits of the line more effectively at any given moment using near real-time conditions. Use of DLRs often yields greater capacity than using static line ratings, which do not account for real-time ambient conditions, and thus provides an opportunity to safely use the existing transmission system more efficiently (DOE 2022b). Potomac Economics (2021a) identifies concerns with the use of conservative static line ratings in the Midwest and Delta regions and estimates that the use of ambient-adjusted line ratings would generate significant benefits. As a result, Potomac Economics (2021a) recommends that MISO improve the flexibility of its systems and processes to enable the use of more dynamic and accurate line ratings.[50]

Like DLRs, dynamic transformer ratings monitor transformer operating temperature to more accurately determine power limitations based on thermal thresholds and can therefore unlock additional transmission capacity with greater accuracy of ratings (DOE 2022b). Transformers are typically rated using criteria that do not exceed a static current rating and a dynamic measure of transformer ratings. The criteria account for variables such as ambient temperature, amount of electrical current delivered to the transformer, age of the transformer, and type of cooling systems installed (DOE 2022b).

PFCs are a set of technologies that reroute power away from overloaded, congested lines onto underutilized, less congested lines in the transmission network. PFCs operate by adjusting physical properties of the line. Along with DLRs and other GETs, PFCs provide another important tool for optimizing the use of the current network (DOE 2022b). Topology optimization software serves a similar function as PFCs by identifying reconfigurations in the grid to route power flows around congested or overloaded transmission elements. Both PFCs and topology optimization software can more evenly distribute power flows across the transmission network, which can increase the capacity of the existing grid (DOE 2022b).

Both DLRs and PFCs are the focus of the 2022 DOE study: *Grid-Enhancing Technologies: A Case Study on Ratepayer Impact*. This study models the impact of GETs in New York under three generation scenarios: a scenario with the renewable generation currently in service in NYISO; a second scenario with 3 GW of additional solar generation capacity and 4 GW of additional wind generation capacity that was in the NYISO Interconnection Queue at the time of the study; and a third scenario with the required renewable generation to achieve 70% renewable generation by 2030. The report outlines customer benefits that could be realized by implementing DLRs and PFCs in these scenarios, including annual avoided curtailment savings ranging from $1.7 million from using DLRs to $9.1 million from using DLRs and PFCs, and adding a new substation. Although the study finds that more traditional upgrades, such as line reconductoring and adding a new substation, could yield the highest savings in avoided curtailment, these upgrades come with an added cost and take longer to deploy. GETs can yield high curtailment savings at a lower cost than traditional transmission solutions in some cases in the near term, and therefore

[49] The maximum amount of current that a wire can safely carry.

[50] Ambient-adjusted rating uses ambient air temperature to adjust line ratings over time.

can be a more efficient use of ratepayer funds (DOE 2022b). The study also outlines recommendations for the further deployment of GETs across different parts of the system.

Advanced conductors and cables can increase transmission transfer capacity

The use of advanced conductors and cables in both new transmission infrastructure projects and existing infrastructure rebuilds and upgrades can significantly increase transmission transfer capacity compared with conventional conductors and cables. Advanced conductors generally refer to electrical conductors that utilize carbon and/or composite cores rather than steel cores typically used in conventional conductors.[51] Carbon and composite core characteristics allow for lower transmission line losses, up to two times the amount of carrying capacity compared with conventional conductors, lower weight, and low sag at higher temperatures, which can address transmission line thermal limitations (DOE 2020b). Recent types of advanced conductors include aluminum conductor composite reinforced, aluminum conductor composite core, and aluminum conductor carbon fiber reinforced conductors. DOE (2020b) also notes that high-temperature superconducting equipment, when used in transmission lines, is capable of transmitting power with little to no electrical losses at lower temperatures and can provide up to 10 times the maximum current-carrying capacity of conventional cables with the same cross-sectional area.

DOE (2020b) finds that advanced conductors and high-temperature superconducting equipment deployment can serve to increase transmission system transfer capacity and can be a particularly efficient and cost-effective method of increasing transmission capacity of the existing system when used to reconductor or replace existing transmission lines. Caspary and Schneider (2022), for example, find an estimated 200,000 miles of existing transmission lines will require replacement over the next decade across NERC regions. The report finds that advanced conductor deployment to address 25% of this aging infrastructure need could increase existing transmission capacity to facilitate up to 27 GW of generation capacity annually over the next decade. The report also finds that increasing transmission capacity by replacing aging transmission lines with advanced conductors would generate at least $140 billion in consumer energy savings over a 10-year period.

Microgrids can bolster the resilience of the transmission system

Integrating microgrids into the grid improves the efficiency and effectiveness of the transmission system (DOE 2020b). Microgrids further serve as an effective platform for integrating DERs and reducing costs while bolstering the resilience of the Nation's electricity system. The value of microgrids has grown with FERC Order 2222, under which the DERs that are aggregated and optimized in microgrids can participate in wholesale energy markets and can realize more of their maximum potential benefits.

The full value of microgrids can be categorized into bulk system services (generation capacity, contingency reserves, etc.), transmission and distribution services (congestion relief, upgrade

[51] The most commonly deployed conventional overhead conductor is the Aluminum Conductor Steel Reinforced conductor.

deferral, etc.), and customer services (demand charge management, reliability, etc.). One utility has characterized 14 unique value streams in planning and using microgrids for benefits now and into the future (Lightner et al. 2020). As of mid-2019, 19 states and the District of Columbia had either adopted or were actively exploring adoption of performance-based ratemaking structures to incentivize utilities to use resources beyond traditional generation to meet capacity needs and achieve high rates of reliability (Wang and Crawford 2019), which microgrids could potentially provide.

With expanding deployments of DERs, microgrids play an increasingly important role as an alternative transmission solution to provide power to meet local loads while supporting grid performance objectives (e.g., reliability, resilience, ancillary services). By doing so, microgrids help defer or avoid the need to build new power lines and can allow communities to have greater control over energy resources. DOE envisions microgrids as building blocks of the future grid that will accelerate the transformation toward more distributed and flexible architecture in a socially equitable and secure manner (DOE 2021).

In Hawaii, Hawaiian Electric is currently working with the National Renewable Energy Laboratory and the Hawaii Natural Energy Institute to identify opportunities for the development of microgrids across Oahu to improve electrical infrastructure resilience (Hawaiian Electric 2023a).

V.e. Siting and Land Use Considerations

Siting transmission can be a major challenge

Multiple studies specify siting of high-voltage lines as a major challenge to transmission expansion, indicating that developers often must navigate multiple state processes and local and federal government requirements. As detailed in FERC (2020), developers are often required to navigate multiple state processes as well as federal and local requirements. To obtain a Certificate of Public Convenience and Necessity,[52] developers of multistate projects must demonstrate that their project is in the public interest in each state. Criteria used to make determinations may differ in each state and may even be inconsistent. For example, some states may focus on intrastate benefits and costs only, while others may also take into account or even require interstate, regional, or national benefits and costs. Further, some states may require broad environmental and economic benefits and costs, while others may consider specific policy goals. The Department funds the Regulatory and Permitting Information Desktop (RAPID) toolkit as a resource to catalog these many differences (*see* accompanying text box).

[52] Certificates of Public Convenience and Necessity go by different names in each state but are generally granted by state public service commissions to indicate than an infrastructure project is deemed in the public interest and therefore is entitled to specific rights, such as eminent domain or rate-basing costs among all customers.

DOE Work on Transmission Permitting

The Department funds the Regulatory and Permitting Information Desktop (RAPID) Toolkit, which provides information about federal, state, and local permitting and regulations for utility-scale renewable energy and transmission projects. Developed and maintained by the National Renewable Energy Laboratory, the toolkit makes permitting information easily accessible from a single site by providing links to permit applications, processes, manuals, and other related resources.

National Renewable Energy Laboratory, The RAPID Toolkit: Facilitating Utility-Scale Renewable Energy Development, https://www.nrel.gov/state-local-tribal/blog/posts/the-rapid-toolkit-facilitating-utility-scale-renewable-energy-development.html.

As stated in Xu et al. (2021), differences in planning and permitting processes of the state and local authorities along the path of a transmission line makes siting transmission a major hurdle. FERC (2020) and Xu et al. (2021) further indicate that obtaining approvals in each state also may be difficult because many states focus on intrastate burdens and benefits. For example, a transmission line that does not directly connect resources within a state might not receive permits required to traverse the state.

Additionally, developers face hurdles during the planning process, wherein differing drivers of transmission needs or siloed consideration of the multiple benefits of transmission may exclude valuable projects or complicate their path to construction. Conflicts also arise over cost allocation, as quantifying and determining who receives the benefits is especially challenging. FERC (2020) adds that the planning and permitting process might further complicate transmission development because in addition to state laws, the project may also be subject to local and federal review. For example, local review may be required for authorizations such as zoning permits and high-voltage transmission lines that cross federal lands may require permits from federal agencies that have different information needs and decision criteria. Overall, NERC (2021) describes high-voltage transmission expansion as time consuming and often involving significant siting challenges.

Co-location of transmission corridors is possible in some cases

Several studies (FERC 2020; Xu et al. 2021; Blaug and Nichols 2023; NGI Consulting et al. 2022) suggest co-locating transmission in transportation corridors could help mitigate some siting and land acquisition issues. Use of existing rights-of-way can limit the amount of greenfield development, keeping new development in areas that have already been disturbed (Blaug and Nichols 2023). Co-location of transmission along highways specifically has the added benefit of enabling electric vehicle charging stations, which will be necessary in high electrification scenarios (NGI Consulting et al. 2023). Several states have moved forward with co-location strategies for transmission lines (FERC 2020; NGI Consulting et al. 2022).

Co-locating transmission lines within existing rights-of-way may be feasible if linear infrastructure corridors near the route of a proposed transmission line exist and contain excess space. Rights-of-way refer to the land surrounding infrastructure equipment that is required for operation (NERC 2022b) and must be kept free of excess vegetation and the built environment that may negatively impact operations. High-voltage transmission lines require a corridor that can be as wide as 65 meters to accommodate the construction and placement of multiple cables (National Grid 2017; PSCW 2011). The right-of-way that must be retained for operation and maintenance can be narrower than that needed during construction.

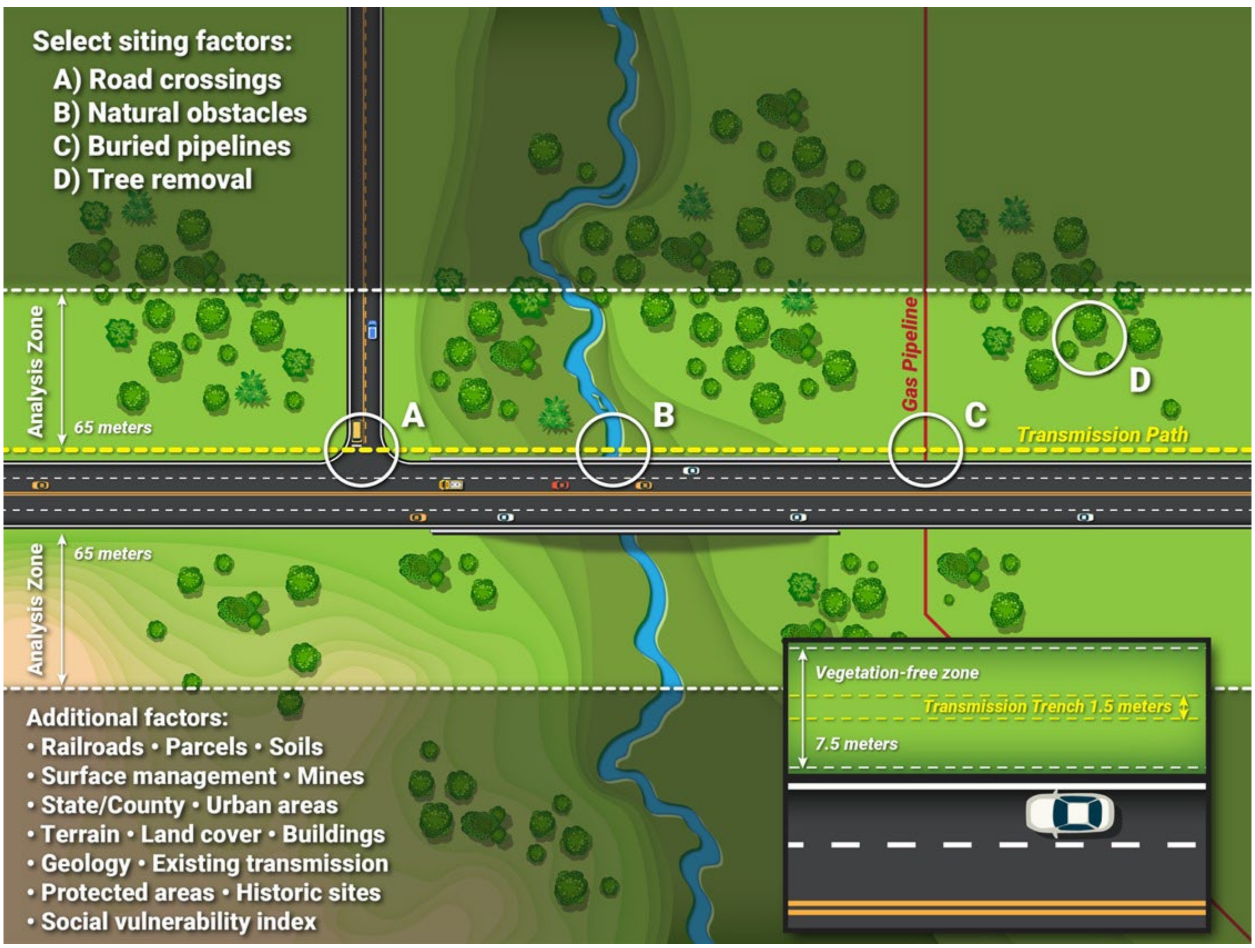
In 2022, researchers at the National Renewable Energy Laboratory (NREL) assessed the feasibility of siting undergrounded transmission lines along highways. This analysis relied on readily available datasets to develop a methodology for assessing highway rights-of-way and did not include any fieldwork that would help to further validate the assessment. High-level outcomes and detailed methods of the NREL effort are documented here and in the Supplemental Material, respectively. The assessment provides a detailed quantification of siting criteria that may impact the development of underground electric transmission lines along the contiguous U.S. interstate system. The analysis focuses on areas within the rural and rural-urban interfaces but does not assess criteria for large cities within metropolitan statistical areas. Specific routes assessed can be found in Figure V-9.

Source: Produced by National Renewable Energy Laboratory. Data from U.S. Department of Homeland Security Geospatial Management Office (GMO 2022)

Figure V-9. Highway right-of-way routes assessed by National Renewable Energy Laboratory. Routes are partitioned by dominant direction.

The analysis uses high-resolution spatial datasets that capture many siting considerations—such as land use conflicts, vegetation cover, terrain, sensitive wildlife habitats, soil composition, and infrastructure intersections—to characterize each acre of land extending 65 meters on either side of major highways. The analysis uses this 65-meter swathe as a conservative estimate of construction width required if several lines were installed (National Grid 2017) and is considered a temporary disturbance of the landscape. In practice, a much smaller, roughly 7.5-meter, permanent right-of-way would be required for each buried transmission line. Figure V-10 presents a conceptual graphic of the analysis conducted for each highway right-of-way.

The NREL analysis provides a first national-scale assessment of relevant siting criteria for direct burial transmission along highway corridors. While the analysis provides unique insights for siting, it does not attempt to evaluate tradeoffs between routes—whether those tradeoffs are economic, social, or technical in nature—and does not select optimal routes. Several high-level outcomes of the analysis are presented next.

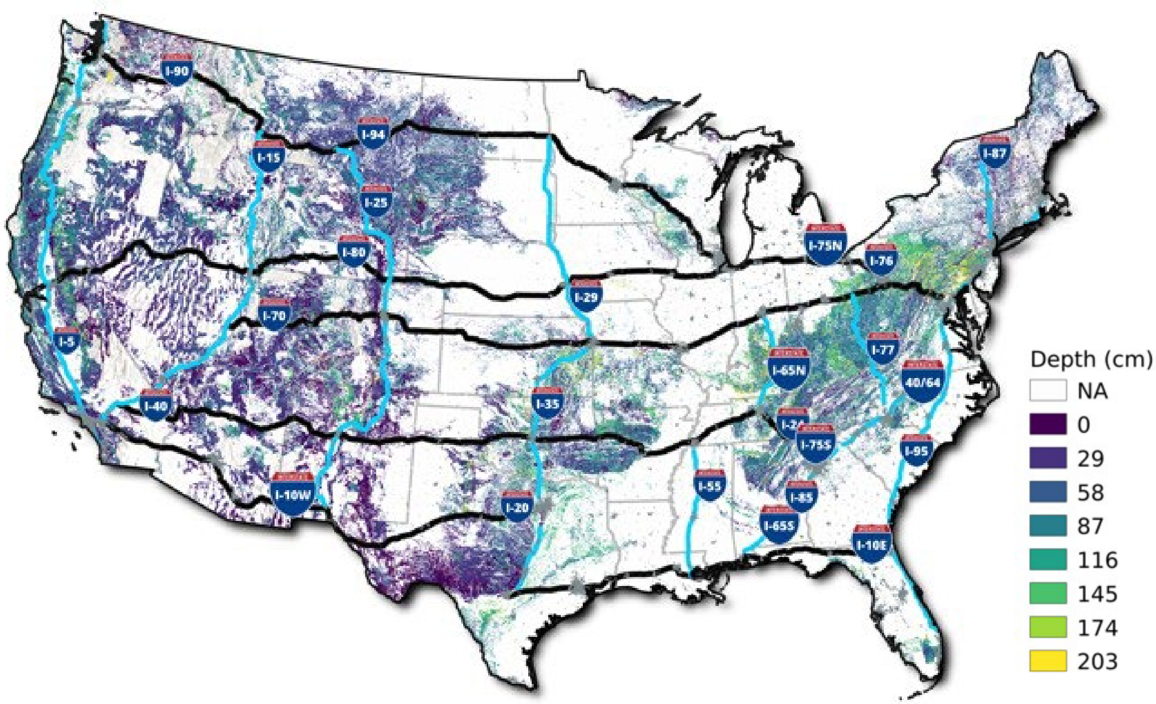


Source: Produced by National Renewable Energy Laboratory.

Figure V-10. Conceptual graphic of the National Renewable Energy Laboratory right-of-way spatial analysis.

It can be costly to site underground transmission along rugged terrain or shallow bedrock depth. Depth to bedrock data provides insight on where undergrounding transmission lines may not be economically feasible. While mountainous areas have both highly rugged terrain and shallow bedrock depth, even relatively flat regions of the country can also have shallow bedrock. Figure V-11 shows the minimum depth to bedrock within the contiguous United States. Highways in the Mountain and Southwest regions have particularly shallow bedrock, as do portions of Texas, the Southeast, the Mid-Atlantic, and New York.

Care must be taken when designing a power line that crosses other infrastructure, such as gas pipelines or roads, to be sure that all can operate safely and without interference. Co-located transmission lines that intersect other infrastructure corridors may require advanced installation techniques, further increasing installation costs. In general, the number of intersections that a highway crosses increases as the route nears major urban centers regardless of where it is located, as shown in Figure V-12. Sections of highway in the Delta (I-10, I-40, I-55), Florida (I-10), Southeast (I-24, I-85), and Midwest (I-39, I-75, I-90, I-94) regions have the lowest number of intersections with other infrastructure.



Source: Produced by National Renewable Energy Laboratory. Data from Natural Resources Conservation Service (NRCS 2019), Geospatial Management Office (GMO 2022).

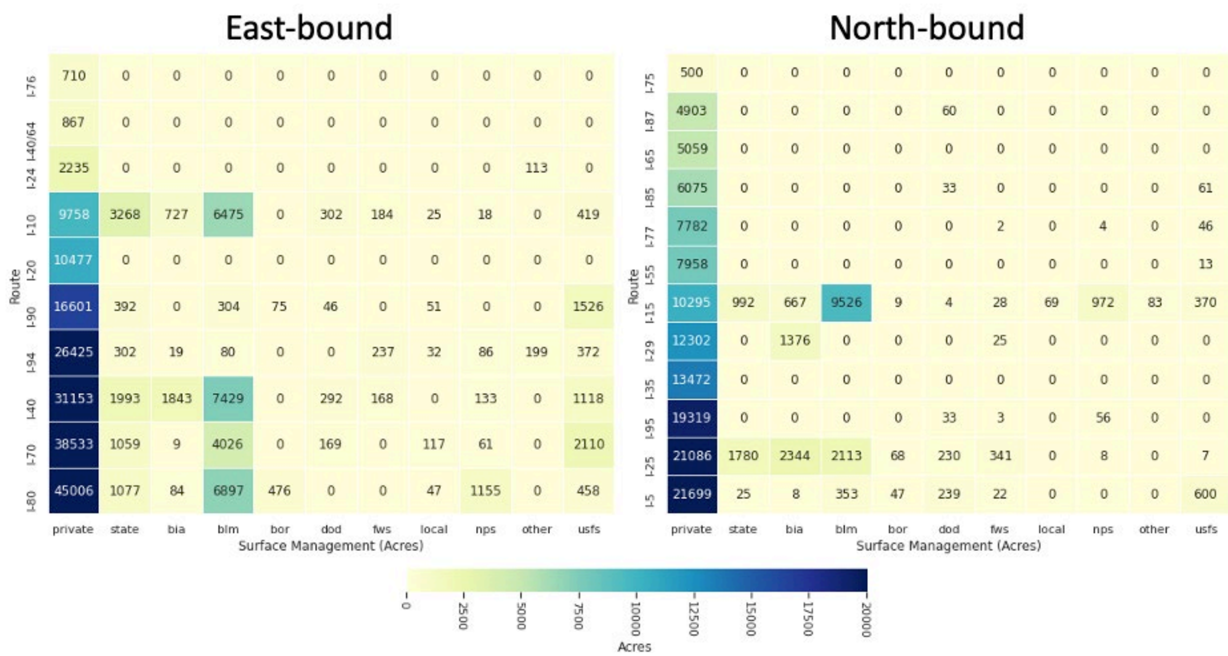
Figure V-11. Minimum depth to bedrock along major highway corridors.

Source: Produced by National Renewable Energy Laboratory. Data from Geospatial Management Office (GMO 2022).

Figure V-12. Highway segments and the count of intersections with other roads, natural gas pipelines, and railroads.

The land alongside interstates is predominantly owned or managed by private entities. Private owners have varied interest in leasing their land to transmission developers, and finding several consecutive owners willing to lease their land for transmission development along a single route can be difficult. Siting along federally managed lands reduces the number of landowners a developer must work with to procure rights-of-way (FERC 2020) but requires a National Environmental Policy Act (NEPA) review to develop. Only a few interstates—notably those east/west routes in the Mountain and Southwest regions (I-10, I-40, I-70, I-80, I-15)—contain significant tracts of state or federally managed lands, as seen in Figure V-13.

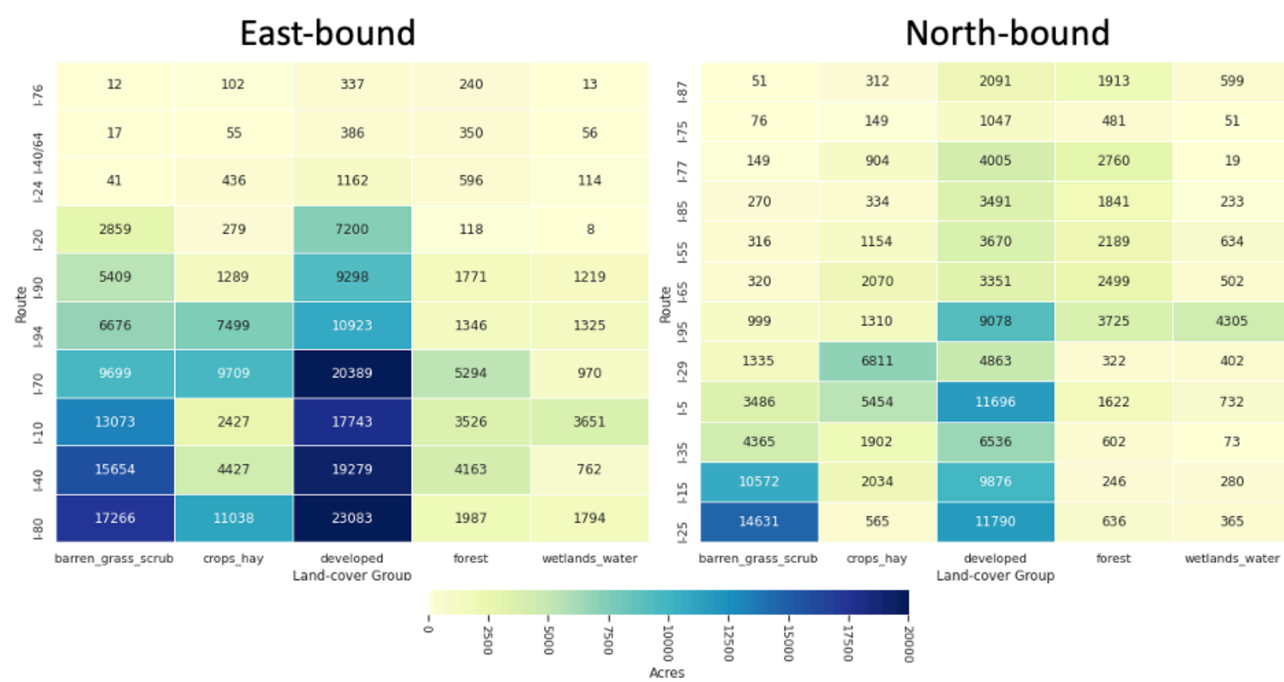
In addition to being predominantly privately owned, the majority of land abutting each interstate is considered "developed," to varying densities of development. Aside from developed land, there are also significant amounts of barren grassland, forests, crops, and wetland along some interstates. Siting transmission is easiest along continuous tracts of open land that limit environmental degradation. Figure V-14 shows the number of acres within each land use/cover grouping by highway route.



Source: Produced by National Renewable Energy Laboratory. Data from Environmental Systems Research Institute, Inc. (ESRI 2018).

Note: Acronyms in the x-axes of these charts refer to Bureau of Indian Affairs ("bia"), Bureau of Land Management ("blm"), Bureau of Reclamation ("bor"), Department of Defense ("dod"), Fish and Wildlife ("fws"), National Parks Service ("nps"), and U.S. Forest Service ("usfs").

Figure V-13. Surface management acres within highway right-of-way by route.



Source: Produced by National Renewable Energy Laboratory. Data from Earth Resources Observation and Science (EROS 2016).

Figure V-14. Land use/cover acres within each highway right-of-way route.

In areas with high levels of existing infrastructure development, transmission siting efforts should account for the cumulative impacts to public health, the environment, cultural resources, or existing social burdens that new transmission infrastructure may magnify (Federal Interagency Working Group on Environmental Justice and NEPA Committee 2016). The NREL analysis highlights that expanding many highway rights-of-way to accommodate transmission could impact already vulnerable communities by considering the Centers for Disease Control Social Vulnerability social vulnerability index (ATSDR 2023) along each highway route. Highways in the Florida, Southeast, Delta, Texas, Southwest, and California regions run through communities with high social vulnerability indices. Sections of highway with the lowest social vulnerability indices are found in the Midwest, Plains, and Mountain regions. The social vulnerability index of communities along all major interstates are shown in Figure V-15.

FERC (2020) and NGI Consulting et al. (2022) identify several regulatory and economic barriers to such co-location. Some state laws prohibit or in other ways restrict the co-location of transmission in highway rights-of-way. Co-location may also increase costs if the highway does not run in the direction compatible with the project. Further, electrical interference can affect the protection systems of oil and gas pipelines and accelerate corrosion, and the induced currents from high-voltage lines can also affect railroad signaling systems. These issues could limit co-location of transmission in pipeline or railroad rights-of-ways.

Source: Produced by National Renewable Energy Laboratory. Data from Agency for Toxic Substances and Disease Registry (ATSDR 2023)

Figure V-15. Highway right-of-way segments characterized by Centers for Disease Control Social Vulnerability Index.

Overhead lines are exposed to air, which serves to insulate the electrical conductors and to cool them. Underground lines often use a gas or fluid oil substrate for cooling within several layers of insulating material (PSCW 2011). The time required to locate and repair a fluid oil leak or electrical fault of an undergrounded transmission line can be more than 25 times as long for an overhead transmission line (National Grid 2017). Both construction and repair costs are higher for undergrounded transmission lines than overhead lines in general (PSCW 2011; National Grid 2017), but the design specifics of any individual project and desirable characteristics of undergrounded transmission lines may offset those concerns. Additional safety and security concerns arise when facilities are co-located; incidents related to one facility can affect the co-located facility due to the physical proximity.

Finally, the volume of soil that must be excavated for undergrounded cables is over 14 times that required for an equivalent overhead line, which only requires relatively shallow excavation for the tower structures intermittent along the length of the line (National Grid 2017). Given the volume of soil disturbed, trenching through farmlands, forests, wetlands, and other natural conservation areas can cause significant land disturbances (PSCW 2011). This is particularly important when designing transmission lines through ecologically sensitive areas.

Given these challenges, overhead power lines have electrical and environmental advantages that could result in fewer siting restrictions than undergrounded cables and could be more feasible to co-locate in some cases.

Transmission siting must balance competing land use interests

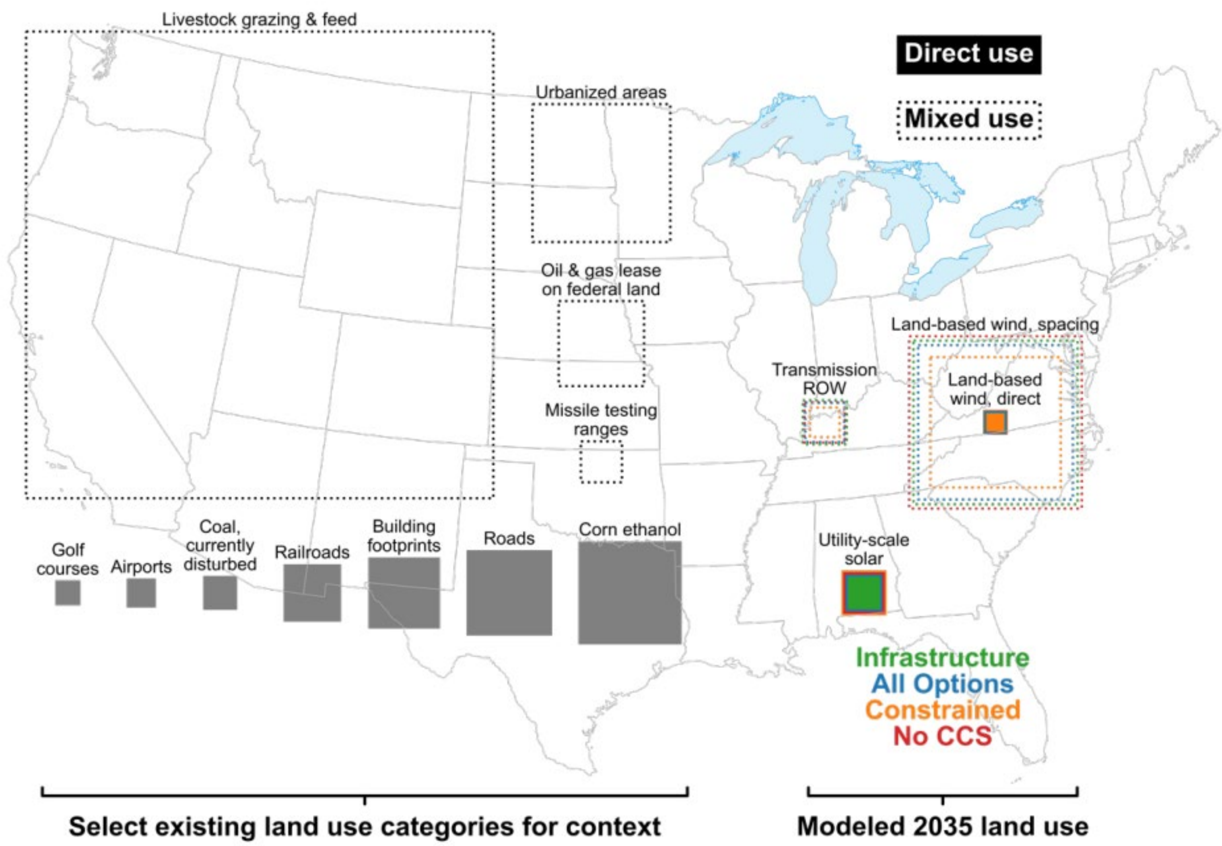
Land acquisition is described as a challenge in transmission development in Ardani et al. (2021). While the United States has large land area, there are often competing interests in the best use of those lands, including energy infrastructure development. Several land-intense energy, industrial, agricultural, and recreational activities are compared in Figure V-16.

Capacity expansion models, like those used in Section VI, try to capture this challenge by significantly increasing the input cost assumptions of transmission development. In their modeling, Cole et al. (2021) increase transmission costs by a factor of five in some scenarios to capture the challenges of siting new lines. These increased costs are meant, in part, to capture the capital cost increases of undergrounding significant portions of transmission lines.

DOE Work on Transmission Siting

The Department is proposing to amend its regulations for implementing Section 216(h) of the Federal Power Act and proposing to establish the Coordinated Interagency Transmission Authorization and Permits (CITAP) 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. The Department's Transmission Siting and Economic Development (TSED) Program, authorized by IRA Section 50152, is designed to build an equitable clean energy economy by accelerating and strengthening Tribal, state, and local transmission siting and permitting processes while promoting economic growth in communities impacted by major new or upgraded transmission lines.

Denholm et al. (2022a) consider land use associated with long-distance transmission rights-of-way under modeling scenarios that achieve a contiguous U.S.-wide 100% clean electricity system by 2035. Transmission can share much of its rights-of-way with other activities, such as agricultural fields or recreational paths, and are considered a "mixed use" activity. This contrasts with other "direct-use" activities, for which the land is solely utilized for the single activity. The primary scenarios in Denholm et al. (2022) result in land use footprint areas for transmission rights-of-way between 13,000 and 28,000 km^2. Figure V-16 illustrates total area occupied by long-distance transmission rights-of-way resulting from the study compared with other common land use activities. The transmission (mixed use) land area resulting from the 100% clean electricity system by 2035 scenarios are roughly equivalent to the footprint of missile testing ranges (mixed use), utility-scale solar (direct use), and currently disturbed coal lands (direct use). The resulting long-distance transmission right-of-way is less than the direct-use land currently used by railroads within the contiguous United States.



Source: National Renewable Energy Laboratory (Denholm et al. 2022a).

Figure V-16. Total area occupied by long-distance transmission rights-of-way compared with other land use activities.

Alaska and the Hawaiian Islands face unique challenges due to their land characteristics and population disbursement. EPA (2020) notes that in Alaska, the remote nature of much of the state, lack of roads, and high financing costs associated with transmission buildout are significant barriers to transmission development. Allen et al. (2016) describes the challenges associated with interconnecting isolated electric grids in rural Alaska due to the small size and geographic remoteness of many rural microgrids as well as harsh weather and terrain, which often make building and maintaining transmission between rural villages impractical. The report also finds that Alaska’s utilities rely heavily on state and federal grants to upgrade and maintain systems. While larger communities and cooperatives may be able to access capital more readily through federal agencies or financial assistance through local financial institutions, smaller rural utilities often have fewer options (e.g., limited to fuel loans from the state or fuel dealers), creating economic limitations, which can lead to underinvestment in infrastructure.

Land use challenges in Hawaii can also create barriers to transmission development. In Kaua’i, for example, transmission development activities must consider the potential impacts to habitats for endangered or threatened species, including seabirds, waterbirds, and the green sea turtle. Conservation measures to mitigate impacts due to transmission development can include powerline reconfiguration, static wire removal, and increased transmission line visibility with reflective or LED lighting to minimize collision on high-risk line segments (KIUC 2023b).

Community, stakeholder, and Tribal engagement is imperative

Electric transmission infrastructure projects have the potential to extend through public, private, and Tribal lands, as well as across multiple state and local government jurisdictions. Meaningful engagement with landowners, communities, stakeholders, and Tribes impacted by new or upgraded transmission project development early in the project is critical to ensure the alignment and support among a broad range of interests and to facilitate successful project completion. Transmission infrastructure can serve to bring location-constrained clean energy generation to load centers and accommodate the retirement of existing fosssil fuel-fired generators, often cited within communities with high energy burdens. Meaningful engagement practices can create a platform for discussion surrounding carbon emission reductions benefits while leading to more equitable siting decision-making.

Blaug and Nichols (2023) describe the conflicting interests between transmission developers and landowners and communities that can often lead to project opposition. In particular, the authors note landowner concerns can typically arise due to potential project impacts on property value, land aesthetic, and/or the surrounding environment, or due to questions regarding potential health impacts or lack of localized benefits. Traditional project development dynamics are typically at the root of many of these concerns, which include the developer's right to exercise eminent domain, as well as the historical procedures of landowner and community engagement only after key routing decisions have been made, leaving complex regulatory approval processes the main avenue for stakeholder participation.

Blaug and Nichols (2023) note the importance for developers to engage early and often in the development process as well as throughout the life of the transmission project to ensure landowners and communities are kept up to date and extended platforms for engagement that demand fewer resources and time compared with many regulatory approval processes. Similarly, Ung-Kono (2023) recommends frequent and sustained community engagement in the transmission development process, particularly in the form of in-person meetings within the communities potentially impacted by the project. In-person community meetings held early in the planning process can serve to build trust and create a collaborative environment where information can be exchanged freely beyond information provided traditionally through existing regulatory approval processes.

Transmission siting and land use activities also intersect with key energy justice issues. Ardani et al. (2021) suggest that community engagement is key to addressing siting concerns and making equitable siting decisions. Ardani et al. (2021) add that transmission infrastructure can raise local opposition because of perceived or real negative impacts on property and the environment. The authors emphasize that increased community engagement is crucial for addressing local concerns and making equitable siting decisions, as historically, marginalized communities have had a disproportionate share of the cost and burdens of transmission network expansion.

In the beginning stages of the transmission siting process, project sponsors may also consider utilizing tools such as EJScreen, EPA's environmental justice mapping and screening tool, the U.S. Census American Community Survey Data, and other environmental justice screening tools developed by various states to identify environmental justice communities and the potential impacts a transmission project may have on communities (Blaug and Nichols 2023). The authors note the importance of identifying key environmental justice communities and conducting outreach early in the development process to determine community needs and how to reduce potential impacts. For infrastructure related to transmission lines, which historically has prioritized placement in low-cost lands, high cumulative burden should be an indicator to avoid those areas. The Department has created a suite of tools to identify areas with increased vulnerability (*see* accompanying text box).

DOE Work on Energy Justice

The Council on Environmental Quality has developed the Climate and Economic Justice Screening Tool, an interactive map indicating community burdens in eight categories: climate change, energy, health, housing, legacy pollution, transportation, water and wastewater, and workforce development. The tool uses this information to identify disadvantaged communities that are experiencing these burdens.

Additionally, the Department has developed an Energy Justice Dashboard (BETA), which displays DOE-specific investments across the country overlaid on the several indicators of community burden described above. DOE is working to better understand how the Department's funding and investments are distributed to overburdened and underserved communities that have been left behind and unheard for too long.

Council on Environmental Quality, Climate and Economic Justice Screening Tool, https://screeningtool.geoplatform.gov/.

Dept. of Energy, Office of Economic Impact and Diversity, Energy Justice Dashboard (BETA), https://www.energy.gov/diversity/energy-justice-dashboard-beta.

Community benefits agreements created in partnership with environmental justice communities during engagement outreach can also be an effective tool in guaranteeing certain community benefits, such as local job creation and training, economic trust fund contributions or financial assistance, and unique revenue sharing or ownership configurations (Blaug and Nichols 2023; Ung-Kono 2023).

Federal agencies can also improve consideration of environmental justice issues as part of the NEPA review process for electric infrastructure projects. The Federal Interagency Working Group on Environmental Justice and NEPA Committee (2016) provide a set of recommendations for how federal agencies can improve engagement efforts while conducting environmental analyses for NEPA review. The report highlights the importance of early and meaningful engagement with potentially affected minority populations, low-income populations, and other populations that often have greater barriers to engagement during key stages of NEPA review. Specifically, the report recommends considering adaptive and innovative approaches to both public outreach engagement during the following stages: defining the affected environment, identifying potentially affected minority and low-income populations, assessing potential impacts to minority and low-income populations, assessing potential alternatives, determining whether potential impacts to minority populations and low-income populations are disproportionately high and adverse, and developing mitigation and monitoring measures.

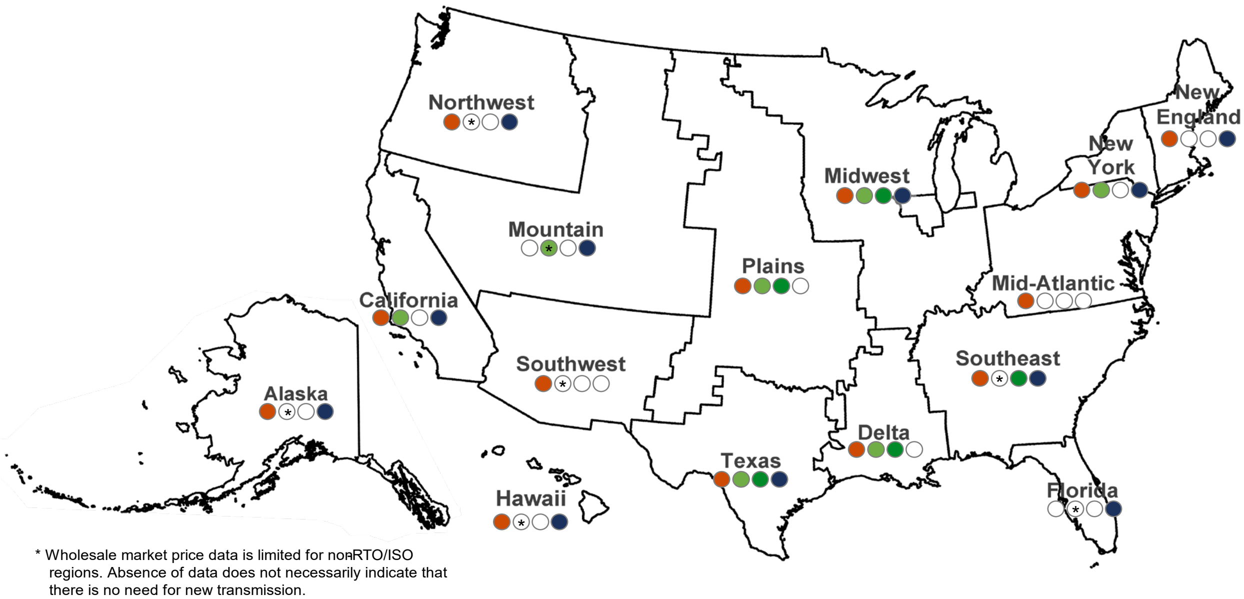
Additionally, the authors note that providing opportunities to discuss both process-specific information as well as the purpose and need of agency action early in the NEPA review process can help guide public input and efficient information collection to inform the decision-making process. Federal agencies may also consider information dissemination through electronic methods (e.g., virtual meetings, webinars, social media, and listservs) and in-person meetings to keep communities updated about procedural details. The report also notes the importance of maintaining relationships throughout the engagement process through a dedicated agency point-of-contact and the value of creating project-specific community advisory committees, or other established groups, which include representatives from potentially affected groups.

Blaug and Nichols (2023) also discuss the importance of project sponsor Tribal engagement. The authors note that while federally mandated Tribal consultation only involves interaction between the federal government and Tribal governments, transmission project sponsors may consider engaging with Tribes earlier in the development process before formal consultation processes begin. Tribal land and ownership of Tribal lands can be complex issues to navigate. For example, different categories of Tribal lands can include reservation land, treaty land, and lands containing cultural and historical Tribal resources, which may be owned by a Tribal government and/or individual Tribe's reservation lands and other homelands to which a Tribe has ongoing cultural and spiritual connections (Blaug and Nichols 2023). Early and meaningful Tribal engagement before key decisions have been finalized regarding project routing can allow for Tribal guidance for how best to avoid impacts to historic properties and culturally significant natural resources. Further, in addition to outreach to Tribal government leaders, developers would benefit to conduct outreach to Tribal communities as well as landowners, who may offer differing perspectives and interests.

V.f. Conclusion and Summary of Transmission Needs and Benefits Identified Across the Reviewed Studies

The studies reviewed as part of this section discuss the key factors driving the current and anticipated need to expand the Nation's transmission system, including grid reliability, resilience, resource adequacy, generation mix and load profile changes, and congestion and curtailment issues. Study findings provide insight into how transmission capacity expansion through new and upgraded transmission infrastructure, as well as alternative transmission solutions, can address these transmission system needs, which are anticipated to increase as the power system continues to evolve. Indicators of system needs and the manner in which transmission can assist in meeting those needs are recurrent across the reports reviewed, which account for a wide range of study regions, modeling tools, and industry perspectives.

Figure V-17 summarizes findings of current and anticipated transmission needs by geographic region as determined by the data and studies referenced in the Section V literature review. The different color circles located on the map of Figure V-17 (top) correspond to the transmission needs listed in the dashboard (bottom).



Region

Current or Anticipated Need

	California	Northwest	Mountain	Southwest	Texas	Plains	Midwest	Delta	Southeast	Florida	Mid-Atlantic	New York	New England	Alaska	Hawaii
Improve resilience & resilience	●	●		●	●	●	●	●	●		●	●	●	●	●
Alleviate congestion & unscheduled flows	●	*	● *	*	●	●	●	●	*	*		●		*	*
Alleviate transfer capacity limits between neighbors					●	●	●	●	●						
Deliver cost-effective generation to meet demand	●	●	●		●		●		●	●		●	●	●	●

Source: See the Supplemental Material for supporting references and methodology.

Figure V-17. Summary of current and future transmission needs identified in Section V by geographic region.

System reliability and resilience remain key drivers in the need for transmission infrastructure in nearly every geographic region across the United States and are anticipated to drive transmission in the future. Nationwide, transmission capacity expansion can serve to enhance system stability through improved operational flexibility, resource sharing, and frequency response. Reliability has been cited as the dominant driver for currently planned transmission projects.

Transmission infrastructure will be particularly important in maintaining system reliability as an increasing amount of VER generation interconnects to the transmission system. Various study findings highlight the need for transmission planning efforts to consider the unique electrical impacts of inverter-based resources, including the potential to cause low inertia, unstable voltage, low fault currents, or unpredictable behavior during grid disturbances. Despite these unique reliability concerns, transmission can accommodate increased VER generation integration in response to future changes in the generation mix while maintaining overall grid reliability.

Transmission can also maintain reliability and bolster system resilience across the Nation in the face of extreme weather events that continue to increase in intensity and frequency. The authors, including many regional planning entities and independent market monitors, identify transmission limitations and highlight transmission needs during recent extreme weather events, including heat waves in Texas, California, and the Northwest; Winter Storms Uri and Elliott; Hurricanes Laura and Ida; and cold weather events such as the 2018 "bomb cyclone" in New England, New York, and the Mid-Atlantic regions and 2019 "polar vortex" in the Midwest, among other events. Expanding transmission capacity between regions can improve the ability of the bulk power system to respond to such extreme weather events through operational flexibility and resource sharing.

The need for additional interregional and cross-interconnection seams transmission capacity is particularly acute between the Plains, Midwest, Delta, Texas, and Southeast regions and their neighboring regions. Interregional and cross-interconnection seams transmission capacity can also enable the system to take advantage of the geographic and temporal diversity of energy resources, which can improve the electric system's ability to transport low-cost clean energy while bolstering system reliability through increased power pathways. A more interconnected grid has been found to also support resource adequacy, as new lines enable more flexible generation sharing, which can reduce the need for new generation in certain instances.

Congestion is a major driver of new transmission infrastructure needs in the California, Northwest, Texas, Plains, Midwest, Delta, Mid-Atlantic, and New York regions, as well as in Alaska and Hawaii. Transmission investments can improve the competition of lowest-cost resources in wholesale markets by reducing congestion. This literature review provides an analysis of region-specific congestion using utility data and market monitor reporting. Load-weighted congestion costs are estimated to be the highest in CAISO and ERCOT. In New England, transmission investments have resulted in lower levels of congestion; however, an anticipated increase in offshore wind interconnection is expected to increase congestion in the southeastern subregion due to export constraints. In New York, congestion and constraints have been found within New York between the upstate and Long Island areas. Significant congestion and constraints have been found to exist in the eastern and coastal parts of the Mid-Atlantic region, between the Midwest and Delta regions, and between eastern to western Texas. The changing generation mix has also introduced congestion in the Plains and in the Western Interconnect. The Plains region, for example, has experienced higher levels of congestion due to increased wind generation output. Alaska's transmission system has limited transmission transfer capacity between generation and major load centers, and certain transmission systems on the Hawaiian Islands, including Kaua'i, require additional transmission capacity. Similarly, the Northwest, Southeast, and New England have also been found to need additional transmission capacity to deliver more cost-effective generation to meet demand.

Recent and anticipated changes in generation mix and load profiles present key drivers for new transmission. Transmission infrastructure at the national level can help accommodate a diverse mix of new, clean VERs. New transmission infrastructure is required to transfer new renewable energy generation from remote or distant areas to load centers as the power system transitions to a decarbonized future. Additionally, various regional planning authority, utility, and state-level planning efforts in the California (and the Western Interconnection at large), Texas, Midwest, Mountain, New York, New England, and Southeast regions note the need to efficiently plan transmission to access location-constrained clean energy resources. As part of the anticipated increase in clean energy integration, transmission expansion can also help to reduce generation curtailment. Further, there is an even greater need for increased transmission buildout as decarbonization efforts may lead to increases in electricity demand due to high levels of end-use electrification. Planning efforts must account for potential reliability risks from increased load growth from electrification impacts.

Alternative transmission solutions can complement new traditional transmission infrastructure, but do not obviate the need for additional infrastructure altogether. Energy storage can serve as a crucial grid asset capable of supporting VER integration by shifting load across hours or days, smoothing seasonal peaks, and providing additional grid services. Hybrid variable renewable energy-plus-storage plants, for example, can also reduce the need for additional transmission when sited near load centers. Similarly, DERs can assist in meeting clean energy targets while lowering electricity costs for consumers. Other solutions, such as GETs and advanced conductors and cables, can help manage transmission congestion and increase transmission line utilization rates by expanding existing transmission system capacity. GETS have the potential to complement traditional transmission expansion by reducing impacts due to outages required for new transmission upgrades and new transmission line interconnection. Similarly, microgrids can present a myriad of transmission benefits, including the ability to provide generation to local load while providing significant reliability, resilience, and ancillary services benefits.

Siting and permitting of new transmission infrastructure, including offshore wind transmission, remain a major challenge to transmission expansion due to disparate state and local siting and permitting processes and varied determinations of project benefits and cost allocation. Land use and land acquisition also present challenges in the transmission development process. In geographic regions such as Hawaii and Alaska, for example, harsh terrain, population disbursement, and environmental concerns also present challenges to transmission siting and development. In certain instances, it may be feasible to co-locate transmission infrastructure within existing transportation corridors to ease siting and land acquisition. However, there remain potential regulatory, economic, or logistical barriers to siting overhead or underground transmission within existing transportation corridors.

Meaningful engagement with landowners, communities, stakeholders, and Tribes early in the transmission development process is key in ensuring equitable transmission solutions that mitigate potential impacts to communities. Project sponsor and federal agency engagement is not only critical to ensure alignment among a broad range of interests, but it is also critical to ensure transmission development processes result in equitable siting decisions that mitigate potential impacts to disadvantaged communities and reduce cumulative energy burdens.

Preliminary results from a Department-led survey directed by the Fiscal Year 2021 Consolidated Appropriations Act suggest that over 54,000 American Indian and Alaska Natives do not have access to electricity today. Approximately 92% of AI/AN respondents reported regular electricity outages, often because of inadequate infrastructure or because they are serviced by a single power line lacking redundancy. Many Tribal lands have an abundance of renewable energy resources, and renewable generation development may provide opportunities for diversification, energy independence, environmental sustainability, and new revenue streams for AI/AK communities. Access to the transmission system would be required to generate such value for Indian Tribes and to bring economically viable generation resources to market.

VI. Anticipated Future Need Assessment through Capacity Expansion Modeling

The U.S. power supply is undergoing a rapid transformation, reflecting evolving market conditions, geopolitical conflicts, and the increasing penetration of new generation and transmission technologies. Given the long development time for high-voltage power lines, the Nation's transmission needs should be defined as much by anticipated future need as current need. Congress has also directed the Department to consider expected future transmission congestion and constraints in this study.

Planning the future power system requires consideration of expected changes in supply and demand, including changing market conditions and consumer demand behavior. Capacity expansion modeling is a common tool used to estimate what the power demand and supply will be in future years. To accommodate many potential futures—for example, electrification of different quantities of end-use appliances and different adoption rates of advanced nuclear technologies—capacity expansion modelers consider multiple scenarios under a range of feasible assumptions.

Once future power system scenarios and input modeling assumptions have been established, capacity expansion models optimize for the lowest capital and operations costs, system wide, to identify the cost-optimal mix of generation, electric storage, and transmission investment. The models consider hourly energy dispatch constraints and some essential grid reliability services, such as resource adequacy.[53] The models optimize around all possible technology combinations and choose the least expensive solutions in each geographic zone given the range of assumptions and scenarios considered.

The capacity expansion modeling studies used here are national in scope and capture a wide range of likely future power sector characteristics. Given the rapid transformation of the power sector, there is value in considering how a diversity of supply and demand futures will impact the transmission system. Scenario-based transmission planning can capture large uncertainty in how supply and demand may change 20 or more years into the future. Capacity expansion modeling studies differ from typical industry-led transmission planning studies, which generally respond to regional, near-term transmission needs by identifying specific transmission projects as solutions (Pfeifenberger et al. 2021), rather than co-optimizing both generation and transmission solutions nationwide to meet regional needs.

The Department analyzed the modeled transmission builds that result from several recent national laboratory and peer-reviewed academic capacity expansion modeling studies to estimate the amount and location of future transmission need. The studies collectively examine hundreds of scenarios, capturing a wide range of possible power system futures. The values presented here are zonal estimates of the amount and general geographic location of future transmission need.

[53] The energy and reserve services considered by each capacity expansion model can be found in the referenced model documentation.

The precise characteristics and nodal locations of specific transmission projects to accommodate supply and demand changes would be determined by additional engineering analysis performed by the transmission planners. Additionally, any portion of these transmission system additions may require associated distribution or transmission system upgrades to support increased energy transfers and, as such, the zonal estimates reported here may underestimate total required system builds. These downstream analyses are critical to the transmission planning process to ensure reliable operation of the grid but are out of scope for the analysis presented here. Because of their nearer-term focus, many industry-led transmission planning studies employ inputs that are naturally more certain about the characteristics of the future power system. Section V reviews the results of many of these studies. Given the mismatch in temporal and geographic modeling scope, the results of the reviewed industry-led transmission planning studies are not included in this analysis.

The Department is currently undertaking a National Transmission Planning Study to bridge the gap between national, long-term capacity expansion modeling studies and regional, nearer-term transmission planning studies (*see* accompanying text box). The National Transmission Planning Study is conducting downstream engineering analysis of candidate transmission projects identified through capacity expansion modeling.

DOE Work on Transmission Planning

The Department is conducting the National Transmission Planning Study to identify transmission solutions that will provide broad-scale benefits to electric customers, inform regional and interregional transmission planning processes, and identify interregional and national strategies to accelerate decarbonization while maintaining system reliability.

Dept. of Energy, Grid Deployment Office, National Transmission Planning Study, https://www.energy.gov/gdo/national-transmission-planning-study.

This section describes future power system scenarios that six capacity expansion studies considered and the resulting amount of new transmission each study modeled. Section VI.a. provides a high-level overview of all model scenarios considered in this analysis and explains how the scenarios were categorized for presentation of results. Section VI.b. explains how alternative transmission solutions are considered by the study scenarios. Sections VI.c. and VI.d. present the resulting regional transmission needed to meet changes in electricity demand and other power sector constraints. Section VI.c. presents the regional transmission expansion results, followed by interregional transfer capacity expansion results in Section VI.d. The transmission expansion results shown here are model outputs that illustrate the amount of anticipated transmission investments needed to meet a large variety of power sector futures. Given the diversity of demand-side, generation, and transmission solutions to future power sector needs, ranges of results are shown. Section VI.e. compares current transmission utility plans with the range of anticipated transmission deployment need according to the capacity expansion modeling results. Conclusions are provided in Section VI.f.

VI.a. Included Studies and Scenarios

The anticipated transmission results of 300 scenarios from six capacity expansion modeling studies published since 2020 were analyzed.[54] The scenarios represent different potential futures for the Nation's power sector, all of which result in different assumptions about future electricity demand and the resulting deployment of transmission. The first study was performed by researchers at the Massachusetts Institute of Technology (Brown and Botterud 2020); four were performed by researchers at the National Renewable Energy Laboratory (Ardani et al. 2021; Brinkman et al. 2021; Cole et al. 2021; Denholm et al. 2022a); and the last was performed by researchers at Princeton University (Larson et al. 2021)). These studies and the results from their core scenarios were reviewed in Section V. Table VI-1 summarizes the six studies discussed here at a high level; a more detailed summary of and the specific treatment of transmission in each study can be found in the Supplemental Material.

Table VI-1. Summary of six reports used in this analysis.

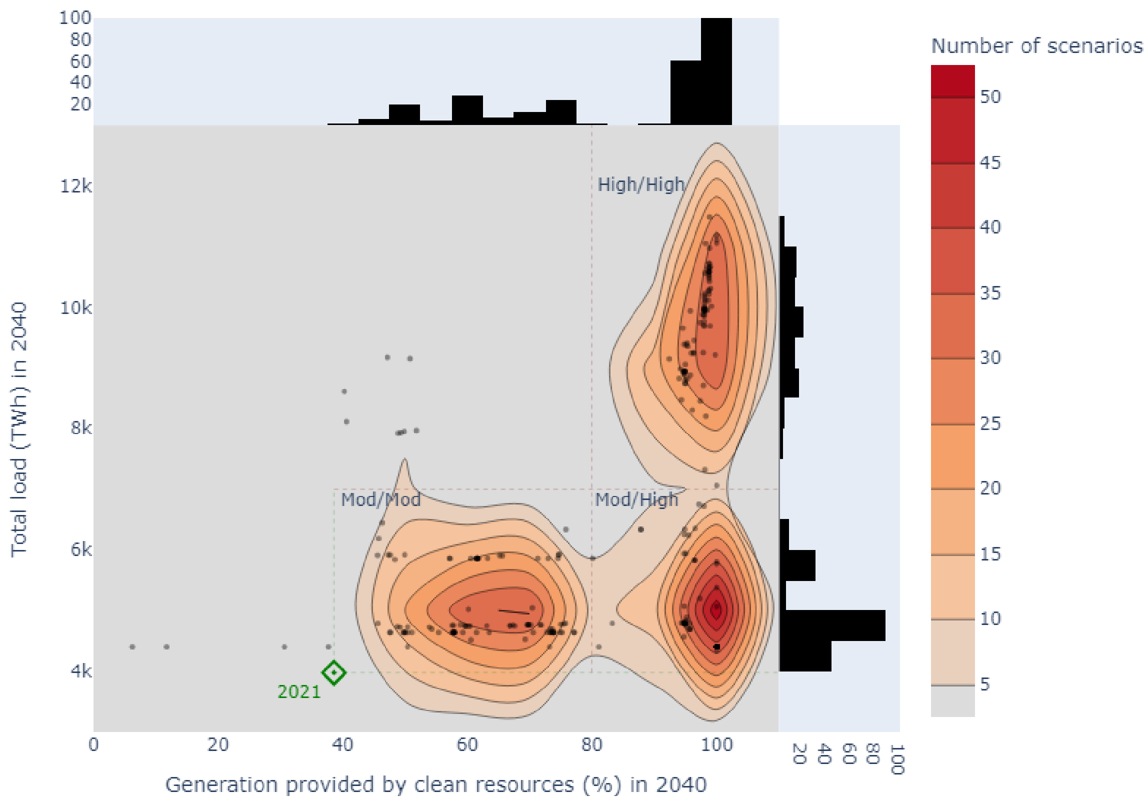
Report	Driving Perspective	Temporal	Geographic	Included Modeling	Scenarios
Mass. Institute of Technology *The Value of Inter-Regional Coordination and Transmission in Decarbonizing the U.S. Electricity System* Brown and Botterud (2020)	Considers costs associated with different transmission coordination and expansion cases, given 100% renewable energy system	<u>Scope</u> 2040 <u>Resolution</u> CEM: single year modeled	<u>Scope</u> Contiguous U.S. <u>Resolution</u> State	• CEM: custom co-optimized, linear capacity planning and dispatch model	Six core scenarios: • No new transmission, no interstate coordination • No new transmission, regional coordination (PA–AC) • New state transmission, regional coordination (PA+AC) • New state transmission, national coordination (USA–AC–DC) • New regional transmission, national coordination (USA+AC–DC) • New regional AC & DC transmission, national coordination (USA+AC+DC) Plus 48 sensitivities
NREL *North American Renewable Integration Study* Brinkman et al. (2021)	Considers impacts on power sector if transmission and generation planning conducted jointly with USA, Canada, and Mexico	<u>Scope</u> 2010–2050 <u>Resolution</u> CEM: 2-yr PCM: 5-min RA: hourly	<u>Scope</u> Continental <u>Resolution</u> Approx. nodal	• Capacity expansion modeling (ReEDS) • Production Cost Modeling (PLEXOS) • Resource Adequacy (PRAS)	Four core scenarios: • Business-as-usual • Low-cost variable generation • Carbon constrained • Electrification Plus 38 sensitivities

[54] Several other studies with anticipated future transmission expansion results reviewed in Section V were considered for inclusion in this analysis. Because of data issues (errors found in results, only preliminary results available at time of analysis, etc.), those studies were excluded.

Report	Driving Perspective	Temporal	Geographic	Included Modeling	Scenarios
NREL *Standard Scenarios* Cole et al. (2021)	Considers possible future power sector scenarios, given different technology costs and system conditions and adoption levels	Scope 2022–2050 Resolution CEM: 2-yr PCM: hourly	Scope Contiguous U.S. Resolution Approx. BA	• Demand-side modeling (dGEn) • Capacity expansion modeling (ReEDS) • Production Cost Modeling (PLEXOS)	Three core scenarios: • No New Policy • 95% by 2050 • 95% by 2035 Plus 47 sensitivities
NREL *Solar Futures Study* Ardani et al. (2021)	Considers role of solar energy, distributed energy, and electrification, given power sector decarbonization	Scope 2020–2050 Resolution CEM: 2-yr PCM: hourly RA: hourly	Scope Contiguous U.S. Resolution Approx. BA	• Capacity expansion modeling (ReEDS) • Production Cost Modeling (PLEXOS) • Resource Adequacy (PRAS)	Three core scenarios: • Reference • Decarbonization • Decarbonization + Electrification Plus 6 sensitivities
Princeton University *Net Zero America* Larson et al. (2021)	Economy-wide net-zero emissions by 2050; implications for land use, capital mobilization, jobs, air pollution assessed for different net-zero energy system pathways	Scope 2020–2050 Resolution CEM: 5-yr	Scope Contiguous U.S. Resolution State (transmission outputs)	• Demand-side modeling (EP) • Capacity expansion modeling for power and fuels sectors (RIO)	Six core scenarios: • Reference • High electrification (E+) • Less high electrification (E−) • Less high electrification, high biomass (E−B+) • High electrification, less high variable energy resources (E+RE−) • High electrification, 100% renewable energy by 2050 (E+RE+)
NREL *Examining Supply-Side Options to Achieve 100% Clean Electricity by 2035* Denholm et al. (2022a)	Considers different pathways to achieve 100% clean electricity by 2035 and net-zero emissions by 2050	Scope 2020–2050 Resolution CEM: 2-yr	Scope Contiguous U.S. Resolution Approx. BA	• Demand-side modeling (dGEn) • Capacity expansion modeling (ReEDS)	Four core scenarios: • All options • Infrastructure renaissance • Constrained Siting • No carbon capture and sequestration Plus 122 sensitivities

The amount of transmission expansion needed to meet future power sector scenarios depends heavily on the generation mix—notably the transition from thermal generators to high penetration of location-dependent clean energy resources—and future demand (Jenkins et al. 2022b). For this reason, the 300 capacity expansion scenarios are analyzed based on these two characteristics. The annual percentage of clean energy generation, including all solar energy technologies (concentrating solar power, utility-scale photovoltaic systems, rooftop photovoltaic systems), land-based and offshore wind power, hydropower, nuclear energy, hydrogen-based technologies, biomass energy, coal and natural gas plants paired with carbon capture and sequestration technologies, and landfill gas plants were considered. Several transmission system operators are preparing for significant load growth in a variety of industries, including data centers and transportation electrification (Gledhill 2021; ERCOT 2021b; ISO-NE 2022a).

Figure VI-1 shows the combination of clean energy generation and electricity demand assumptions for all study scenarios in 2040. [55] The two outer histograms show the scenario counts with respect to clean energy penetration (x-axis) and total annual load (y-axis) individually. The center contour plot shows the scenario counts for both clean energy penetration and total load, considered together. A single point on the contour plot indicates the amount of clean energy and load assumed for a single scenario. Red shading contours indicate where many datapoints are clustered. The darker the shading, the more scenarios have that level of clean energy penetration and total load. The open diamond indicates the clean energy penetration (38.6%) and total annual load (3,974 TWh) in 2021 (EIA 2022a). Any scenarios to the right of the diamond indicate an increase in total clean energy penetration in 2040 compared to today's levels. Any scenarios above the diamond indicate a growth in total annual load compared to today's load.



Note: Histogram (black bars along x- and y-axes) and contour (red topographical lines in center plot) axes are shown counts of scenarios. The diamond indicates 2021 levels (EIA 2022a). Thresholds separating the three scenario groups are shown as dashed lines, and each scenario group is labeled.

Figure VI-1. Counts of study scenarios describing the amount of clean energy generation (as percentage of total annual generation) and the total annual load in 2040.

[55] Please refer to source documentation of each study to understand the specific generation mixes considered and modeled in each.

Three general groups of scenarios emerge from the contour plot, as shown by the outermost contour line in Figure VI-1. Using the contours as a guide, linear thresholds are applied to categorize scenarios into three groups:

- **Moderate/Moderate:** moderate load growth between 2021 baseline (3,974 TWh) and 7,000 TWh and moderate clean energy penetration between 2021 baseline (38.6%) and 80% in 2040; 2021 load and penetration values from EIA (2022a).
- **Moderate/High:** moderate load growth between 2021 baseline (3,974 TWh) and 7,000 TWh and high clean energy penetration above 80% in 2040.
- **High/High:** high load growth above 7,000 TWh and high clean energy penetration above 80% in 2040.

All studies considered scenarios with different utility, state, and federal power sector policies modeled—such as state clean energy standards or energy efficiency laws—based in part on the existing utility, state, and federal policies in place at the time of each study. It is important to note that modeling for all studies was performed before the passage of the bipartisan Infrastructure Investment and Jobs Act of 2021 and the Inflation Reduction Act of 2022 (IRA). It is anticipated that these laws will have dramatic impacts on future generation and demand that were not modeled among the business-as-usual and existing policy scenarios presented here (Jenkins et al. 2022b, Steinberg et al. 2023). Transmission solutions will be needed to accommodate the generation and load changes enabled by financial incentives included in both laws.

The Moderate/Moderate scenario group includes many scenarios that modeled various changes in market forces to drive changes in generation and load, ignoring any existing or new power sector policies. Nearly all studies' business-as-usual or reference scenarios fall into this scenario group. Some scenarios that considered new policies—such as 95% clean energy generation nationwide by 2050—also fall into this group. Scenarios from all six studies are represented in the Moderate/Moderate scenario group. The Moderate/Moderate scenario group most closely represents the evolution of the power system had the IIJA and IRA not been enacted and are, therefore, an unlikely representation of future power sector need.

The Moderate/High scenario group includes a diverse mix of different market forces and policy scenarios. Many scenarios that model 95% clean electricity generation by 2035 or 2040 fall into this group. Scenarios from all six studies are represented in the Moderate/High scenario group. On a nation-wide basis, the Moderate/High scenario group best represents the future power system that could be enabled by current (as of the publication date of this Needs Study) utility, local, state, and federal policies, including the large investments in clean generation technologies expected to be made possible by the IRA.[56] While these scenarios are now within

[56] Several studies anticipate that IRA will enable power sector carbon dioxide emissions to reduce by 70%–91% in 2030 compared with 2005 emissions (DOE 2022c; Jenkins et al. 2022a; Larsen et al. 2022; Mahajan et al. 2022; Roy et al. 2022; Steinberg et al. 2023). This most closely aligns with the power sector carbon dioxide emissions enabled by scenarios in the Moderate/High scenario group. The spread of 2030 carbon emissions reductions (compared with 2005 levels) for scenarios used in this analysis are 30%–72% for the Moderate/Moderate scenario group, 70%–80% for the Moderate/High scenario group, and 80% for the High/High scenario group. More details about the carbon emission reductions reached by all scenarios are found in the Supplemental Material.

the range of possibility given current policies, they are not inevitable and will require action—not least of which is the rapid upgrade of the Nation's transmission system—by the power sector community to achieve (Jenkins et al. 2022b; Steinberg et al. 2023).

The High/High scenario group only includes scenarios in which new policies are enacted, most notably policies that encourage high amounts of electrification and the adoption of energy intensive technologies. Certain regions (e.g., California, New England, New York) have decarbonization and load growth policies (NRRI 2021) more in line with the High/High scenario group assumptions. This group is dominated by scenarios from Denholm et al. (2022a), which model 100% clean electricity supply by 2035 to support large load growth from electrification, hydrogen production, and carbon capture and sequestration technologies to support economy-wide net-zero greenhouse gas emissions by 2050.

Only a few scenarios that fall outside these three scenario groups—notably those in which load growth from high electrification outpaces clean energy technology deployment—were considered by some studies (*see* Figure VI-1). Given the small sample size of scenarios outside the three categories identified here, they are not considered in this analysis. Furthermore, scenarios that disallowed building of interregional transmission were excluded from this analysis. Interregional transmission can be the most cost-effective solution to meet transmission needs in some circumstances, and experts have identified interregional solutions as critical to addressing emerging reliability and resilience needs. For that reason, we consider scenarios that arbitrarily disallow these solutions even where the models find them to be the cost-effective option too restrictive. Additional information about all study scenarios and which scenarios were included in each scenario group is found in the Supplemental Material.

VI.b. Treatment of Alternative Transmission Solutions

There are several different combinations of generation and transmission solutions to meet regional electricity demands. Co-locating generation and storage units, siting generation close to load, and siting generation far from load with long transmission lines connecting the two are all examples of different solutions. Capacity expansion models will identify the least-cost choice among these combinations to meet reliability and load requirements.

Capacity expansion models quantify transmission capacity in terms of power carrying capacity (GW) or power carrying capacity across distance (GW-mi). These quantities are inherently technology neutral. When capacity expansion models find that new GW or GW-mi of transmission capacity is needed, this need could be met, at least in part, by increasing the carrying capacity of existing transmission infrastructure. For example, using DLRs or reconductoring existing transmission lines could enable transmission system operators to make better use of the full carrying capacity of existing transmission infrastructure. All results presented in the subsequent sections could be met with a combination of transmission technologies, both traditional and emerging alternatives. Additional engineering analysis performed by transmission planners is needed to determine the best technologies and locations of the available transmission solutions to meet the needs identified here.

Alternative transmission solutions could be used in addition to new traditional AC transmission lines to meet the needs identified here. These solutions include strategically placed generation near load centers, GETs, energy storage, and DERs. Any of these solutions could help lower, but are unlikely to eliminate, the need for new "poles and wires" transmission infrastructure. Some of these solutions are explicitly included in the capacity expansion modeling results analyzed here. The grid reliability services provided by many alternative solutions are not fully captured in capacity expansion modeling, however, but their value in reducing overall system costs is captured.

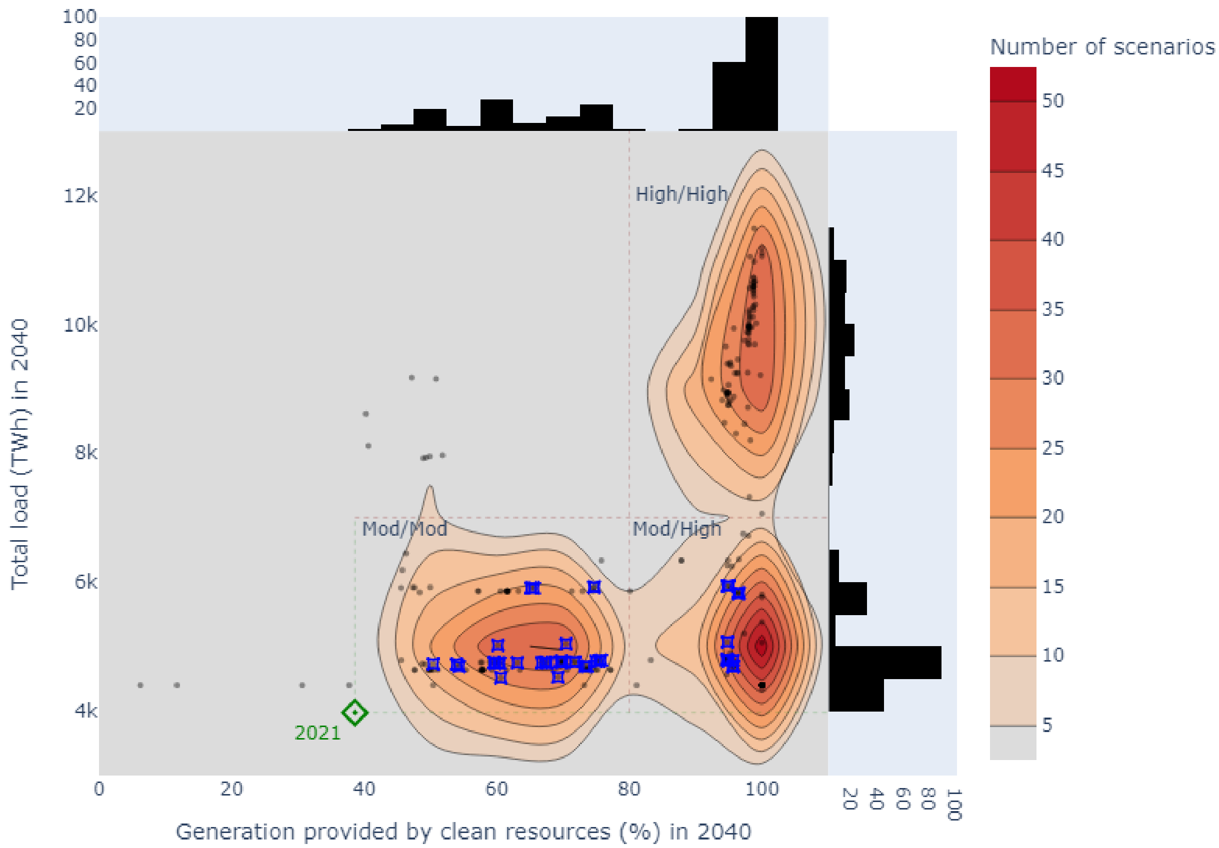
Energy storage resources enable a more efficient use of the grid and are increasingly important for grid reliability with increased demand from electrification (Ardani, et al. 2021). All studies except Larson, et al. (2021) co-optimize future capacity expansion of diurnal, stand-alone storage[57] among their respective suites of generation resources. The location of any new storage facilities identified by the models could be near generation or at key locations in the transmission network where their energy arbitrage and reserve services are most beneficial. All studies find large growth in energy capacity of storage technologies, notably batteries, under numerous scenarios to meet future power system changes. Storage capacity is found to increase from 1 GW of installed capacity in 2020 (EIA 2022) to between 25 GW and 325 GW in 2040 across all scenarios considered by Cole et al. (2021). Brown and Botterud (2020) find increased deployment of 3,500 GWh to 11,500 GWh of storage energy by 2040 with more storage necessary to balance a less coordinated grid.

As described in Section V.d., Vibrant Clean Energy's report, *Why Local Solar for All Costs Less* (Clack et al. 2020), considers the economic and social impacts of increased adoption of DERs, namely distributed solar photovoltaic systems. Clack et al. (2020) compares the results of two high DER scenarios with business-as-usual scenarios to measure those impacts. These scenarios consider approximately 200 and 300 TWh of annual distributed solar production, respectively, in 2040.

There are 47 scenarios in this analysis that include over 200 TWh of distributed solar generation in 2040: nine from Ardani et al. (2021) and 38 from Cole et al. (2021). Fourteen of these scenarios are in the Moderate/High scenario group, and the remaining are in the Moderate/Moderate scenario group. The 47 high DER scenarios are shown as blue boxes in Figure VI-2. All high DER scenarios contribute to the range of transmission and transfer capacity need identified in the subsequent sections.

High DER scenarios do not necessarily result in lower transmission or transfer capacity builds than other scenarios. Nearly half of the high DER scenarios in the Moderate/Moderate scenario group resulted in higher-than-average 2040 transmission deployment compared with all scenarios in that group. The high DER scenarios in the Moderate/High scenario group had lower-than-average 2040 transmission deployment compared to all scenarios in that group but were not among the lowest builds of the group. As found in Clack et al. (2020), new transmission infrastructure is needed to accommodate high DER penetration in some regions.

[57] Storage technologies considered include pumped hydro and between 2- and 12-hour durations of battery storage.



Note: See Figure VI-1. Blue boxes indicate scenarios with at least 200 TWh of annual energy production from DERs.

Figure VI-2. Histograms and contour plot for all study scenarios describing the amount of clean energy generation (in percentage of total annual generation) and the total annual load in 2040 with high DER scenarios indicated.

VI.c. Within-Region Transmission Deployment

All studies calculated the amount of new transmission deployment within a region modeled to meet different future scenarios.[58] Given the diversity of future scenarios considered, a range of results is presented in the results shared here.

Transmission deployment is presented as the increase in carrying capacity (GW or TW) of a modeled power line multiplied by the length (miles) of the line. Quantifying power lines as GW-mi or TW-mi is convenient for capacity expansion models but is not a common practice in industry. Transmission planners and developers quantify power lines by their nominal voltage rating (kV) multiplied by the length (miles) of the line. In general, the higher the voltage rating

[58] Because the estimation of transmission miles used in the NREL *North American Renewable Integration Study* is from a vintage version of the ReEDS model, which underestimated mileage, those results are not used here. NREL is constantly updating its ReEDS model. Information about the model can be found in the Supplemental Materials.

and the shorter the power line, the more carrying capacity it has. Table VI-2 from NRRI (1987) provides approximate conversions between nominal voltage ratings and distances to carrying capacity for traditional AC transmission lines. By these conversions, a 100-mile, 345 kV rated line is equivalent to 86 GW-mi.

Table VI-2. Approximate power carrying capabilities (MW) of uncompensated AC transmission lines at different voltage ratings and lengths from NRRI (1987).

Nominal Voltage (kV) → Line Length (miles) ↓	138	161	230	345	500	765
50	145	195	390	1,260	3,040	6,820
100	100	130	265	860	2,080	4,660
200	60	85	170	545	1,320	2,950
300	50	65	130	420	1,010	2,270
400	NA	NA	105	335	810	1,820
500	NA	NA	NA	280	680	1,520
600	NA	NA	NA	250	600	1,340

A summary of median new transmission deployment (in TW-mi) for the contiguous United States as a whole and each region is presented in Table VI-3 for all scenario groups in 2030, 2035, and 2040. National transmission deployment considers all within-region transmission in the contiguous United States, not including interregional transmission (described next in Section VI.d.). The values represent the cumulative new transmission deployed by the stated year, less the modeled 2020 system. The approximate amount of transmission that currently exists in each region from Denholm et al. (2022a) is provided in Figure VI-4 for reference.

Table VI-3 and Figure VI-3 through VI-6 show the model results of new transmission deployment within each region for each scenario group in 2030, 2035, and 2040. The range of results is skewed right for almost all regions, indicating that a minority of scenarios show very high transmission builds. The interquartile range (IQR) (middle 50% of result distribution) and the median are shown in these figures for each region separately.

Table VI-3. Median of regional transmission deployment results for each study scenario group in 2030, 2035, and 2040. Both new transmission in TW-mi and percent growth from 2020 system are shown.

Region	2020 TW-mi	Scenario Group	New in 2030		New in 2035		New in 2040	
			TW-mi	% Growth	TW-mi	% Growth	TW-mi	% Growth
CONUS	85.6	Mod/Mod	11.6	14%	17.0	20%	20.9	24%
CONUS	85.6	Mod/High	23.4	27%	54.5	64%	42.2	49%
CONUS	85.6	High/High	33.2	39%	109.8	128%	123.0	144%
California	4.29	Mod/Mod	0.06	1.5%	0.07	1.6%	0.08	1.8%
California	4.29	Mod/High	0.09	2.1%	0.12	2.8%	0.12	2.9%
California	4.29	High/High	0.05	1.1%	0.16	3.7%	0.23	5.4%
Mountain	3.48	Mod/Mod	1.46	42.1%	1.66	47.9%	1.86	53.5%
Mountain	3.48	Mod/High	2.28	65.5%	3.14	90.4%	2.88	82.9%
Mountain	3.48	High/High	3.12	89.7%	6.00	173%	7.69	221%
Northwest	15.24	Mod/Mod	0.03	0.2%	0.04	0.3%	0.08	0.5%
Northwest	15.24	Mod/High	0.07	0.4%	0.54	3.5%	0.00	0.0%
Northwest	15.24	High/High	0.62	4.1%	4.71	30.9%	8.54	56.1%
Southwest	5.66	Mod/Mod	0.41	7.3%	0.63	11.2%	0.78	13.7%
Southwest	5.66	Mod/High	0.93	16.5%	1.87	33.0%	0.81	14.3%
Southwest	5.66	High/High	2.75	48.7%	6.69	118%	7.64	135%
Texas	6.43	Mod/Mod	2.78	43.2%	4.35	67.7%	5.68	88.3%
Texas	6.43	Mod/High	6.04	93.9%	9.00	140%	9.60	149%
Texas	6.43	High/High	3.33	51.8%	7.27	113%	8.72	136%
Delta	3.36	Mod/Mod	0.01	0.2%	0.15	4.6%	0.40	12.0%
Delta	3.36	Mod/High	0.39	11.5%	1.65	49.2%	1.37	40.8%
Delta	3.36	High/High	2.98	88.7%	7.76	231%	8.79	262%
Florida	2.97	Mod/Mod	0.00	0.0%	0.08	2.7%	0.15	5.0%
Florida	2.97	Mod/High	0.06	2.1%	0.81	27.3%	1.04	35.1%
Florida	2.97	High/High	0.01	0.3%	0.73	24.4%	1.04	34.9%
Mid-Atlantic	14.60	Mod/Mod	0.56	3.9%	0.96	6.5%	1.11	7.6%
Mid-Atlantic	14.60	Mod/High	1.09	7.5%	3.28	22.5%	3.61	24.7%
Mid-Atlantic	14.60	High/High	2.49	17.1%	8.84	60.5%	11.69	80.1%
Midwest	11.92	Mod/Mod	1.13	9.5%	2.26	19.0%	3.40	28.5%

Region	2020 TW-mi	Scenario Group	New in 2030		New in 2035		New in 2040	
			TW-mi	% Growth	TW-mi	% Growth	TW-mi	% Growth
Midwest	11.92	Mod/High	3.71	31.2%	13.34	112%	16.22	136%
Midwest	11.92	High/High	7.73	64.8%	20.70	174%	23.40	196%
New England	1.94	Mod/Mod	0.02	0.9%	0.03	1.6%	0.05	2.4%
New England	1.94	Mod/High	0.05	2.5%	0.10	5.2%	2.72	140%
New England	1.94	High/High	0.37	18.9%	2.44	126%	2.98	154%
New York	0.82	Mod/Mod	0.00	0.0%	0.00	0.0%	0.00	0.0%
New York	0.82	Mod/High	0.00	0.0%	0.00	0.0%	0.06	7.6%
New York	0.82	High/High	0.10	12.5%	0.38	46.1%	0.41	50.4%
Plains	6.97	Mod/Mod	1.56	22.4%	2.93	42.1%	3.93	56.3%
Plains	6.97	Mod/High	3.52	50.5%	8.32	119%	6.31	90.5%
Plains	6.97	High/High	6.88	98.7%	28.47	408%	31.26	449%
Southeast	8.90	Mod/Mod	0.55	6.2%	1.09	12.2%	1.58	17.7%
Southeast	8.90	Mod/High	2.83	31.8%	6.82	76.6%	6.04	67.9%
Southeast	8.90	High/High	2.68	30.1%	9.11	102%	11.46	129%

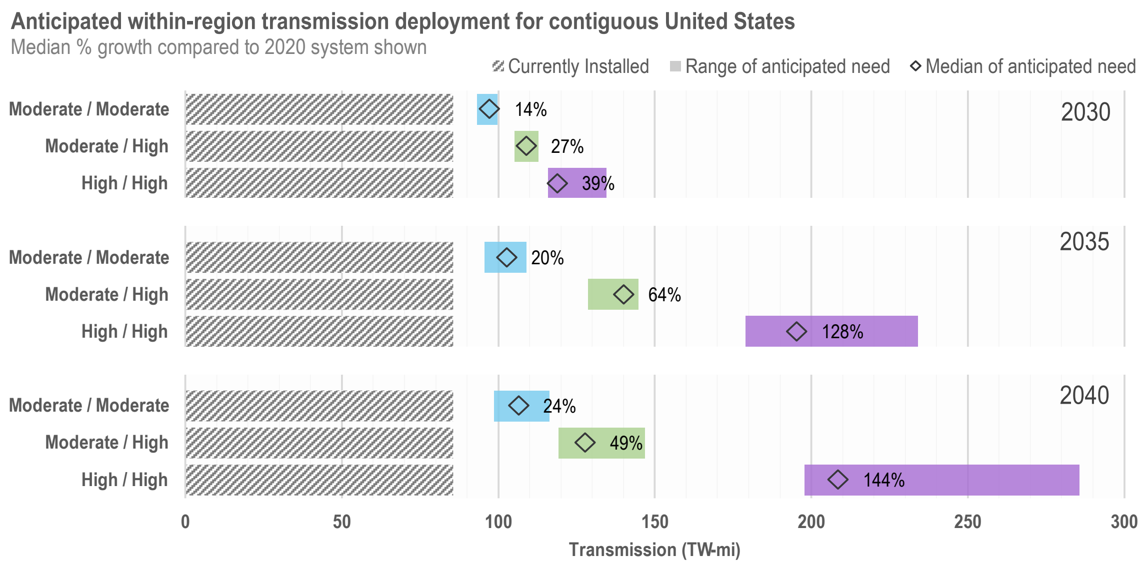
Note: The 2020 existing system for each region is taken from Denholm et al. (2022a). While median results are cumulative and not incremental, the median 2040 transmission deployment appears to be lower than the 2035 median for some regions, especially in the Moderate/High scenario group. The 2040 results include scenarios from Brown and Botterud (2020), which modeled lower transmission builds in many regions compared to other studies included in this analysis, bringing the median result lower for this year compared to 2035.

Figure VI-3 shows the interquartile range of national transmission deployment results for all three scenario groups in 2030, 2035, 2040. National transmission deployment considers all within-region transmission in the contiguous United States, not including interregional transmission. As expected, more clean energy generation and load growth require more transmission to be deployed to maintain reliable power system operations into the future. In 2030, median within-region transmission deployment is needed to grow by 27% to meet the power sector demands of the Moderate/High scenario group and by 39% for the High/High scenario group.

Figure VI-4 shows the transmission results for the Moderate/Moderate scenario group, which defines a power system without the IIJA and IRA enacted. Studies consistently find that the largest transmission expansion will take place in Texas to meet future power sector changes across all years. In 2035, the median transmission expansion in Texas is 4,350 GW-mi, nearly 70% of its 2020 size. Transmission is expanded more in the Mountain region (2035 median of 1,660 GW-mi, nearly 50% current size) than other regions in the Western Interconnection. In the Eastern Interconnection, modeling results show the most transmission expansion in the Southeast (1,090 GW-mi, 12% growth by 2035), Midwest (2,260 GW-mi, 19% growth), and Plains (2,930 GW-mi, 42% growth).

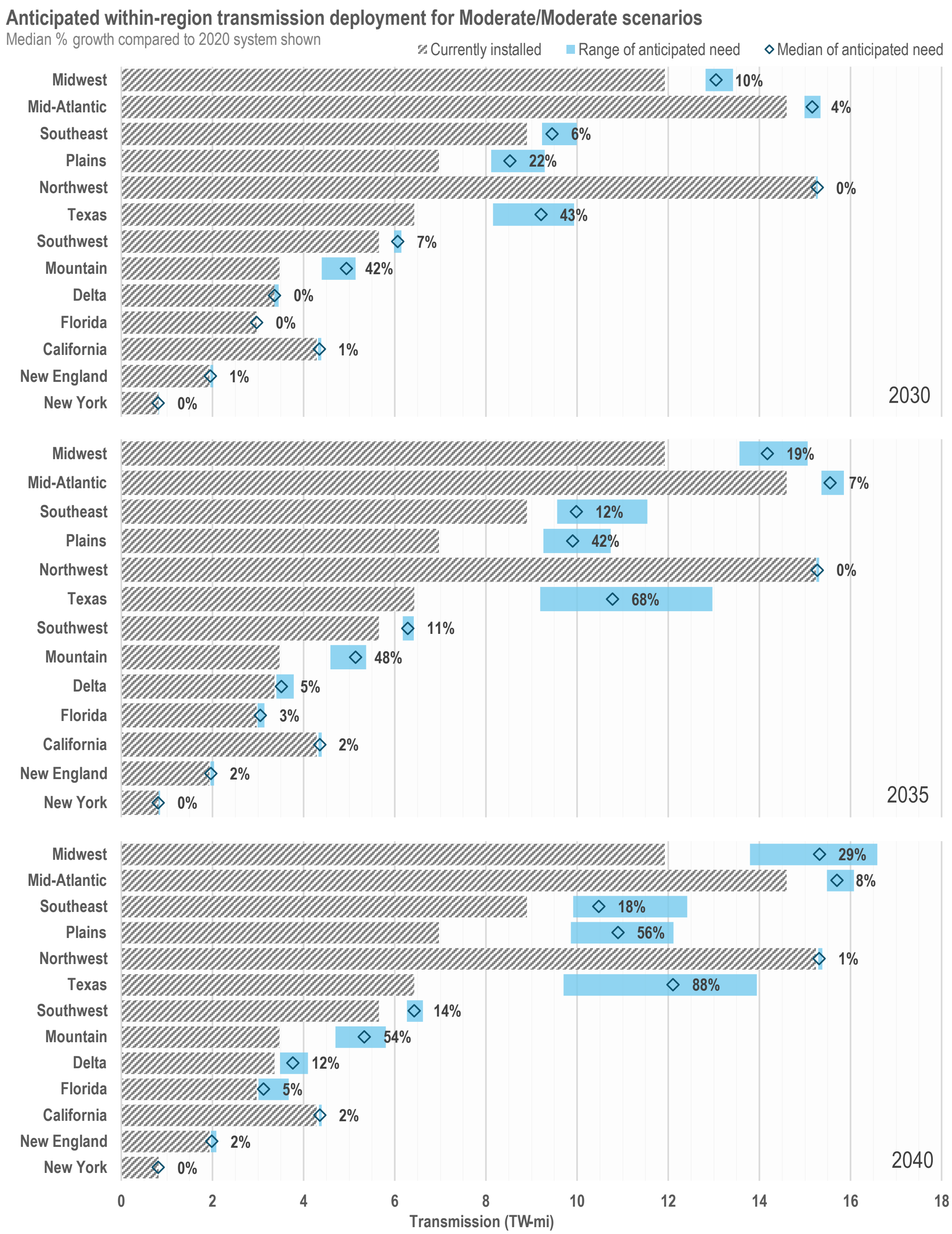
Figure VI-5 shows the results for the Moderate/High scenario group, which, at the time of publication, represents a likely power sector future given recently enacted laws. The regional trends are similar in this scenario group as the previous, with the largest transmission expansion again occurring in the Texas, Mountain, Southeast, Midwest, and Plains regions. These regions also have large IQRs of expansion results compared with other regions. The median transmission expansion in 2035 in Texas is 9,000 GW-mi, a 140% growth compared with the 2020 system. Scenario results suggest that the transmission system in the Mountain, Plains, and Midwest regions will double in size by 2035 to meet the power sector needs modeled in this scenario group (2035 median expansion values of 3,140 GW-mi, 8,320 GW-mi, and 13,340 GW-mi, respectively). These results demonstrate the heavy reliance on clean energy in the middle of the contiguous United States that must be connected to a reinforced power grid to serve load centers.

Figure VI-6 shows the results for the High/High scenario group. These scenarios assume high economy-wide decarbonization and load growth nationwide, which will not be realized throughout the nation without additional state and federal policies. Insights about particular regions with high decarbonization or load growth goals (e.g., California, New York, and New England) (NRRI 2021) can be gained from results in this scenario group. However, these scenarios do assume that all regions of the country are on a similar decarbonization trajectory. This group results in the most transmission expansion, which is necessary to meet the high load growth—driven predominantly by electrification and industrial hydrogen production—scenarios in this group. Additional transmission in the Midwest and Plains greatly exceeds that of all other regions under the high load growth scenarios, again pointing to the large reliance on transmission to access low-cost generation in the middle of the United States. The Southeast and Delta regions also experience large transmission builds—a doubling and tripling of the 2020 system, respectively—in this scenario group compared to the lower load growth scenarios.



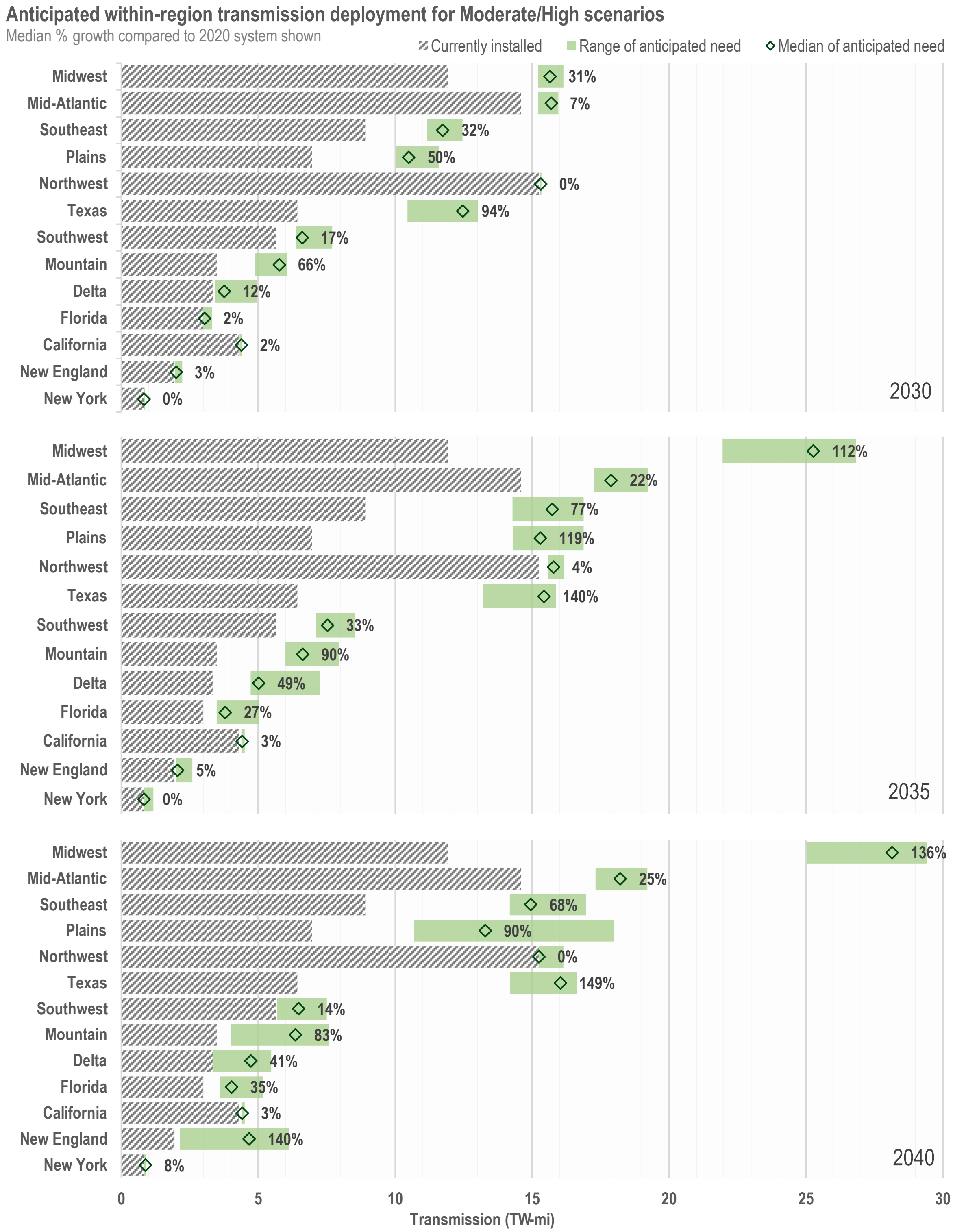
Note: New transmission relative to the 2020 system is shown for 2030 (top), 2035 (middle), and 2040 (bottom). Median and IQR of new transmission results shown. Currently installed transmission as pictured from Denholm et al. (2022a). While results are cumulative and not incremental, the 2040 transmission deployment appears to be lower than the 2035 in the Moderate/High scenario group. The 2040 results include scenarios from Brown and Botterud (2020), which models lower transmission builds in many regions compared with other studies included in this analysis, bringing the median result lower for this year compared to 2035.

Figure VI-3. Regional transmission deployment for contiguous United States across all scenario groups.



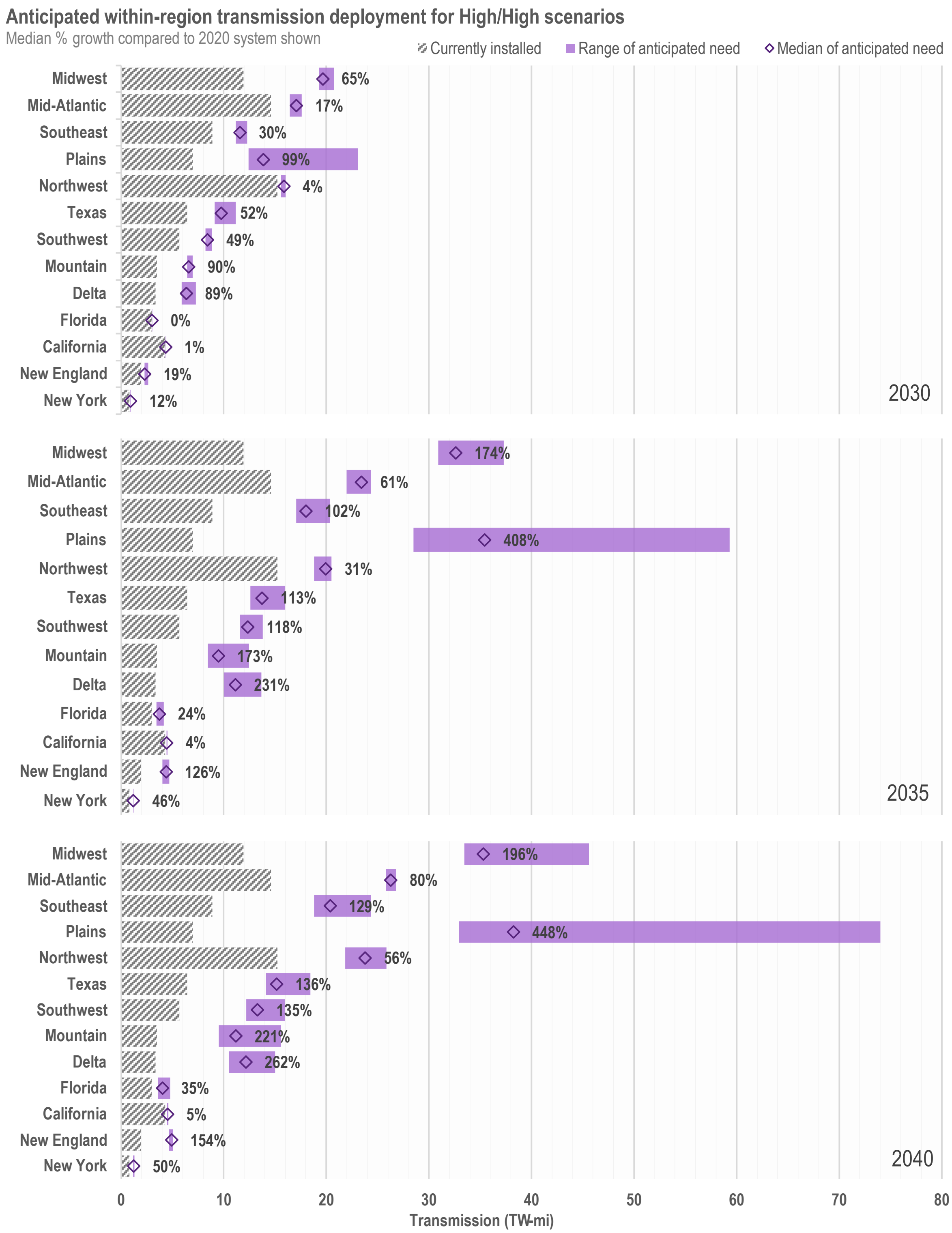
Note: New transmission relative to the 2020 system is shown for all regions for 2030 (top), 2035 (middle), and 2040 (bottom). Median and IQR of new transmission results shown. Currently installed transmission as pictured from Denholm et al. (2022a).

Figure VI-4. Regional transmission deployment for all scenarios in the Moderate/Moderate scenario group.



Note: New transmission relative to the 2020 system is shown for all regions for 2030 (top), 2035 (middle), and 2040 (bottom). Median and IQR of new transmission results shown. Currently installed transmission as pictured from Denholm et al. (2022a).

Figure VI-5. Regional transmission deployment for all scenarios in the Moderate/High scenario group.



Note: New transmission relative to the 2020 system is shown for all regions for 2030 (top), 2035 (middle), and 2040 (bottom). Median and IQR of new transmission results shown. Currently installed transmission as pictured from Denholm et al. (2022a).

Figure VI-6. Regional transmission deployment for all scenarios in the High/High scenario group.

VI.d. Interregional Transfer Capacity

Whereas the previous set of results focused on new transmission deployment *within* a region to meet growing demand, this section focuses on new transfer capacity needed *between* regions. Capacity on a transmission line means the ability 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. Transfer capacity, in turn, means the amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission system by way of all transmission lines or paths between those areas under specified system conditions. Transfer capacity has many benefits. For one, regional grid reliability and resilience is strengthened by the diversity of generation by geographic location and energy resource type provided by interregional transfers. Regions are also able to import electricity when they cannot meet growing demand with local generation or when the combination of remote generation and interregional transmission has lower overall system costs than local generation. Conversely, regions are able to export excess electricity to offset the costs for consumers in their region.

Transfer capacity differs from transmission deployment results in the previous section by focusing on the amount of power that new or upgraded transmission lines can move between neighboring regions, regardless of the length of the lines that make that connection across boundaries. For that reason, transfer capacity results are shown as GW of power between regions, instead of as GW-mi of new transmission lines. The amount of transfer capacity needed between regions to support different futures was calculated by all studies except Larson et al. (2021), which reports deployment only in capacity-miles and not capacity alone.

A summary of the median new transfer capacity results (in GW) for the contiguous United States as a whole and each region is presented in Table VI-4. It is reasonable to assume that increased transfers between regions not modeled by the studies considered here would decrease the size of transfers modeled between other regions. For example, if capacity expansion studies had considered increased transfers between Texas and the Southwest, then the resulting transfers between Texas and the Plains may have decreased. But these shifts in transfer capacities with different neighbors are unlikely to be equivalent. Interregional transfers can offer several operational benefits, such as resource diversification, in addition to just energy capacity access. Planning models may optimize for a solar energy-rich region to increase its transfer capacity with a neighboring region with excess geothermal resources, for example, rather than with a neighbor similarly rich in solar energy. Studies find this to be true for the New England region, where increased transfer capabilities with hydropower resources in Canada can be used to balance offshore wind generation (Dimanchev et al. 2020; Jones et al. 2020).

Table VI-4 for all scenario groups in 2030, 2035, and 2040. National transfer capacity considers all interregional transmission in the contiguous United States, not including within-region transmission deployment. The approximate amount of transfer capacity that currently exists among all regions is provided for reference. Data from Denholm et al. (2022a) were used to approximate the existing transfer capacities between regions, as it is the most up to date of all studies.

Three interregional transfers in Table VI-4 and the subsequent figures—Mountain to Plains, Plains to Texas, and Plains to Southwest—represent increased transfer across the three interconnections. These transfer capacities are modeled as increased DC intertie connections, like those connections that already exist between the interconnections.

Links between neighboring regions are absent from Table VI-4 and subsequent figures if they were not considered by the modelers. For example, the potential creation of an offshore transmission system to support Atlantic offshore wind generation may allow the New England and Mid-Atlantic regions to share direct transfers without needing to transfer through the terrestrial New York system. None of the studies considered here modeled this connection so it is not included here. Also missing are international transfers with Canada or Mexico. Only Brinkman et al. (2021) considers international transfers, and only for scenarios in the Moderate/Moderate scenario group. Given the small sample size, these transfers are excluded here but can be found in the Supplemental Material.

There is currently no transmission connection between Texas and the Mountain, Southwest, or Delta regions (ERCOT 2022a). None of the studies considered here model new future connections between Texas and the Mountain or Southwest regions. Brown and Botterud (2020) is the only study that models new future connections between Texas and the Delta, and only for the year 2040.[59] These results are excluded from the table because of the small sample size. All other studies only assumed transfer capacity expansion between Texas and the Plains.

It is reasonable to assume that increased transfers between regions not modeled by the studies considered here would decrease the size of transfers modeled between other regions. For example, if capacity expansion studies had considered increased transfers between Texas and the Southwest, then the resulting transfers between Texas and the Plains may have decreased. But these shifts in transfer capacities with different neighbors are unlikely to be equivalent. Interregional transfers can offer several operational benefits, such as resource diversification, in addition to just energy capacity access. Planning models may optimize for a solar energy-rich region to increase its transfer capacity with a neighboring region with excess geothermal resources, for example, rather than with a neighbor similarly rich in solar energy. Studies find this to be true for the New England region, where increased transfer capabilities with hydropower resources in Canada can be used to balance offshore wind generation (Dimanchev et al. 2020; Jones et al. 2020).

Table VI-4. Median regional transfer capacity results for each scenario group in 2030, 2035, and 2040. Both new transfer capacity in GW and percent growth from 2020 system are shown.

Regional Pair	2020 GW	Scenario Group	New in 2030		New in 2035		New in 2040	
			GW	% Growth	GW	% Growth	GW	% Growth
CONUS	109	Mod/Mod	15.5	14%	27.5	25%	37.6	34%
CONUS	109	Mod/High	33.2	30%	124.6	114%	239.4	219%

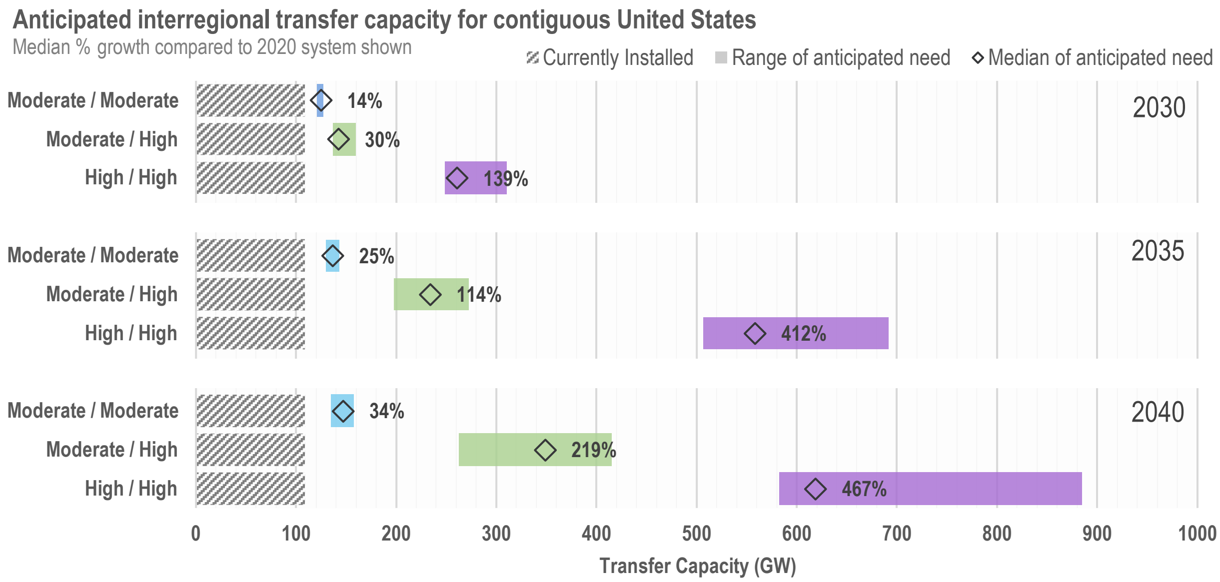
[59] The median transfer capacities between Texas and the Delta are 22.2 GW in the Moderate/Moderate scenario group, 48.3 GW in the Moderate/High scenario group, and 106.7 GW in the High/High scenario group in 2040 for scenarios considered by Brown and Botterud (2020).

Regional Pair	2020 GW	Scenario Group	New in 2030		New in 2035		New in 2040	
			GW	% Growth	GW	% Growth	GW	% Growth
CONUS	109	High/High	151.5	139%	449.0	412%	509.5	467%
California – Mountain	2.12	Mod/Mod	0.31	14.7%	0.96	45.4%	1.80	84.8%
California – Mountain	2.12	Mod/High	0.58	27.3%	1.87	88.1%	4.97	235%
California – Mountain	2.12	High/High	1.21	57.0%	2.75	130%	4.31	204%
California – Northwest	5.15	Mod/Mod	0.00	0.0%	0.00	0.0%	0.00	0.0%
California – Northwest	5.15	Mod/High	0.00	0.0%	0.13	2.5%	0.00	0.1%
California – Northwest	5.15	High/High	0.25	4.8%	1.28	24.9%	1.94	37.7%
California – Southwest	5.23	Mod/Mod	0.00	0.0%	0.14	2.7%	0.22	4.3%
California – Southwest	5.23	Mod/High	0.05	0.9%	0.31	5.9%	5.09	97.3%
California – Southwest	5.23	High/High	1.90	36.4%	5.31	102%	6.89	132%
Mountain – Northwest	12.7	Mod/Mod	0.00	0.0%	0.09	0.7%	0.51	4.0%
Mountain – Northwest	12.7	Mod/High	1.08	8.5%	3.30	26.0%	0.00	0.0%
Mountain – Northwest	12.7	High/High	6.25	49.2%	25.7	202%	39.2	308%
Mountain – Southwest	4.06	Mod/Mod	0.04	0.9%	0.09	2.2%	0.38	9.5%
Mountain – Southwest	4.06	Mod/High	0.37	9.1%	1.65	40.6%	1.70	41.7%
Mountain – Southwest	4.06	High/High	2.08	51.2%	5.24	129%	6.06	149%
Mountain – Plains	0.92	Mod/Mod	0.36	39.1%	0.94	102%	1.40	152%
Mountain – Plains	0.92	Mod/High	0.79	85.4%	2.64	287%	11.9	1,290%
Mountain – Plains	0.92	High/High	6.10	663%	19.3	2100%	29.2	3,170%
Plains – Southwest	0.40	Mod/Mod	0.69	172%	1.16	290%	1.48	370%
Plains – Southwest	0.40	Mod/High	2.53	631%	3.66	914%	13.1	3,280%
Plains – Southwest	0.40	High/High	5.54	1380%	13.0	3,240%	14.4	3,600%
Plains – Texas	0.82	Mod/Mod	0.02	3.0%	0.49	60.0%	0.91	111%
Plains – Texas	0.82	Mod/High	1.15	140%	9.84	1,200%	14.6	1,780%
Plains – Texas	0.82	High/High	14.3	1750%	28.9	3,520%	34.9	4,260%
Delta – Midwest	3.00	Mod/Mod	0.00	0.0%	0.00	0.0%	0.00	0.0%
Delta – Midwest	3.00	Mod/High	0.00	0.0%	0.00	0.0%	0.00	0.0%
Delta – Midwest	3.00	High/High	0.10	3.2%	0.91	30.4%	1.32	44.2%
Delta – Plains	4.76	Mod/Mod	0.00	0.0%	0.35	7.4%	0.73	15.3%
Delta – Plains	4.76	Mod/High	4.89	103%	19.7	414%	0.00	0.0%
Delta – Plains	4.76	High/High	20.7	434%	48.5	1020%	55.3	1160%
Delta – Southeast	5.92	Mod/Mod	0.00	0.0%	0.00	0.0%	0.00	0.0%
Delta – Southeast	5.92	Mod/High	0.92	15.6%	5.10	86.2%	10.7	181%
Delta – Southeast	5.92	High/High	10.1	171%	33.9	572%	37.7	637%

Regional Pair	2020 GW	Scenario Group	New in 2030		New in 2035		New in 2040	
			GW	% Growth	GW	% Growth	GW	% Growth
Florida – Southeast	3.60	Mod/Mod	0.00	0.0%	0.00	0.0%	0.00	0.0%
Florida – Southeast	3.60	Mod/High	0.00	0.0%	1.14	31.6%	7.20	200%
Florida – Southeast	3.60	High/High	0.87	24.2%	10.6	295%	12.9	360%
Mid-Atlantic – Midwest	21.7	Mod/Mod	1.10	5.1%	2.39	11.0%	2.65	12.2%
Mid-Atlantic – Midwest	21.7	Mod/High	9.87	45.5%	33.8	156%	21.9	101%
Mid-Atlantic – Midwest	21.7	High/High	42.4	196%	103	475%	119	550%
Mid-Atlantic – New York	2.00	Mod/Mod	0.00	0.0%	0.29	14.7%	0.81	40.6%
Mid-Atlantic – New York	2.00	Mod/High	0.00	0.0%	2.43	122%	14.8	742%
Mid-Atlantic – New York	2.00	High/High	2.03	102%	8.24	412%	12.7	634%
Mid-Atlantic – Southeast	7.07	Mod/Mod	0.19	2.6%	0.51	7.3%	1.50	21.3%
Mid-Atlantic – Southeast	7.07	Mod/High	2.78	39.3%	6.86	97.1%	12.5	177%
Mid-Atlantic – Southeast	7.07	High/High	4.36	61.7%	9.88	140%	12.2	173%
Midwest – Plains	12.1	Mod/Mod	1.35	11.2%	3.14	26.0%	3.62	30.1%
Midwest – Plains	12.1	Mod/High	7.99	66.3%	21.1	175%	23.0	191%
Midwest – Plains	12.1	High/High	24.6	204%	88.0	731%	98.7	819%
Midwest – Southeast	8.27	Mod/Mod	0.00	0.0%	0.00	0.0%	0.00	0.0%
Midwest – Southeast	8.27	Mod/High	1.28	15.4%	4.46	53.9%	6.23	75.3%
Midwest – Southeast	8.27	High/High	10.3	125%	34.4	416%	39.9	483%
New England – New York	2.03	Mod/Mod	1.46	71.7%	2.84	140%	2.90	142%
New England – New York	2.03	Mod/High	1.53	75.1%	5.19	255%	11.4	559%
New England – New York	2.03	High/High	3.96	195%	17.0	835%	21.4	1050%

Note: The 2020 existing national system for each region is taken from Denholm et al. (2022a). While median results are cumulative and not incremental, the median 2040 transmission deployment appears to be lower than the 2035 median for some interregional pairs, especially in the Moderate/High scenario group. The 2040 results include scenarios from Brown and Botterud (2020), which models lower transmission builds in many regions compared with other studies included in this analysis, bringing the median result lower for this year compared to 2035.

Figure VI-7 through Figure VI-10 show the amount of interregional transfer capacity (in GW) needed between all regions for each of the three scenario groups in 2030, 2035, and 2040. Figure VI-7 shows the total interregional transfers within the contiguous United States. Like the previous set of results, the IQR (middle 50% of the distribution) and the median of all results are shown in these figures for each regional transfer separately. Additional, common statistical values can be found in the Supplemental Material for each scenario group.



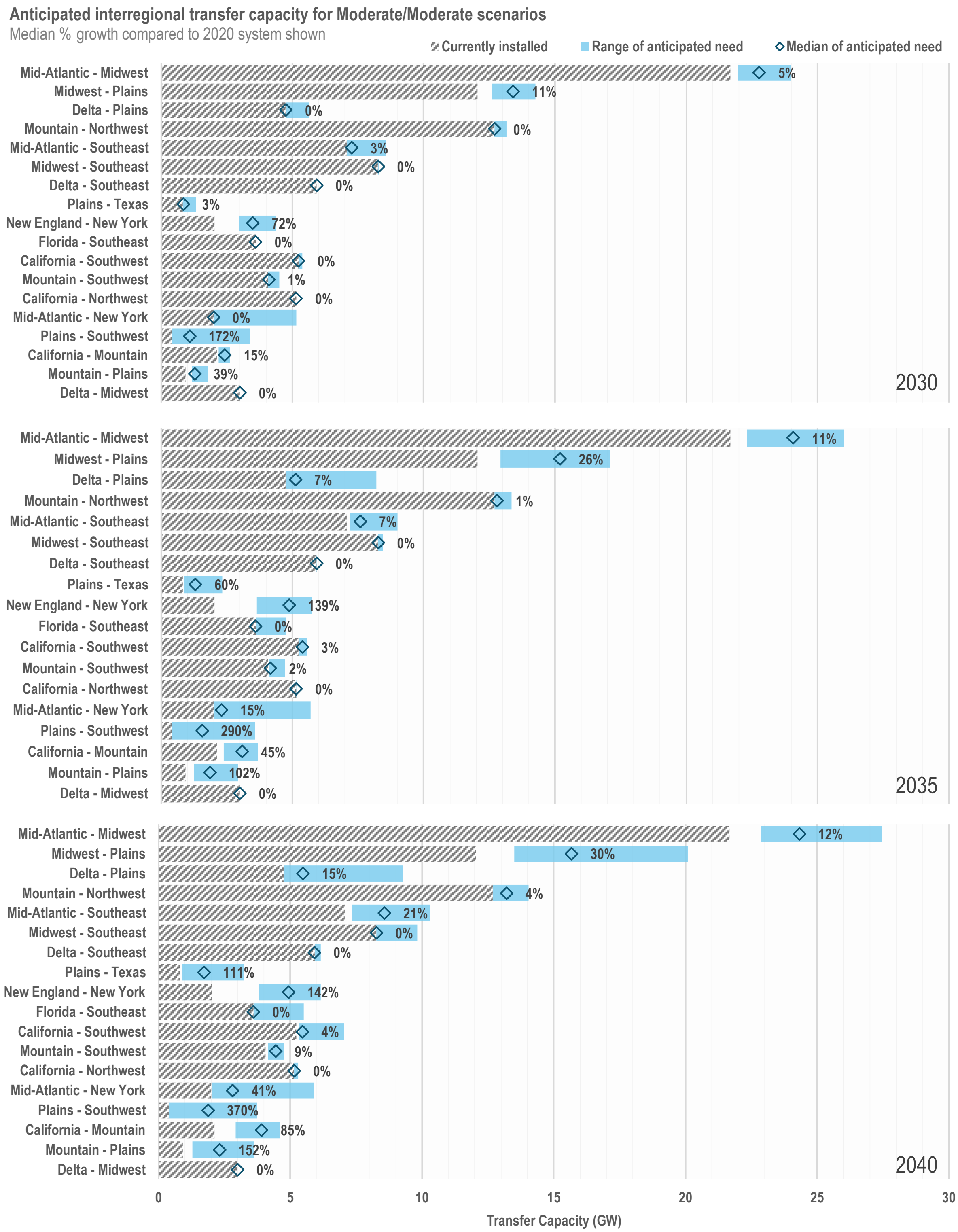
Note: New transfer capacity relative to the 2020 system is shown for 2030 (top), 2035 (middle), and 2040 (bottom). Median and IQR of new transfer capacity results are shown. Currently installed transfer capacity is as pictured from Denholm et al. (2022a).

Figure VI-7. Interregional transfer capacity for contiguous United States across all scenario groups.

Figure VI-8 shows the required interregional transfer capacity for the Moderate/Moderate scenario group in 2030, 2035, and 2040, which defines a power system without the IIJA and IRA enacted. These results are relatively low, indicating that local generation within a region can meet regional demand needs for modeled scenarios in this group. There is moderate transfer capacity expansion in the northern half of the Eastern Interconnection. Highest transfers are found between New England and New York (2035 median of 2.8 GW, 140% growth) and between the Midwest and Plains (2035 median of 3.1 GW, 26% growth). Models show a range of increased transfer between the Eastern and Western Interconnections through the Plains and Southwest. In 2040, the median new transfer capacity between these two regions is 1.5 GW, a small absolute number but a nearly 370% increase from the current transfer capacity.

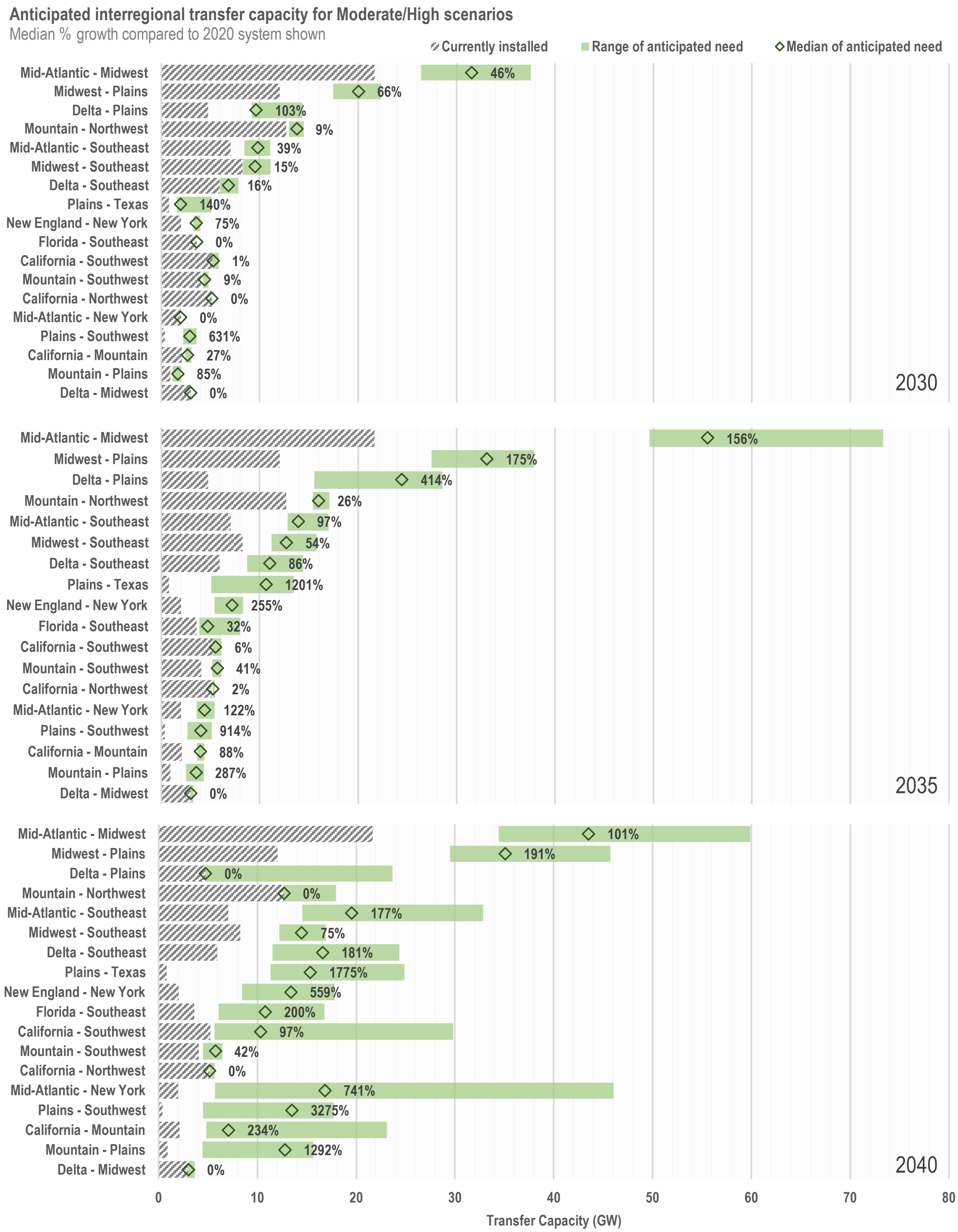
Figure VI-9 shows the required interregional transfer capacity for the Moderate/High scenario group in 2030, 2035, and 2040, which, at the time of publication, is the most likely power sector future given recently enacted laws. Capacity transfers in the Eastern Interconnection continue to dominate in this scenario group, but with increased expansion in new regions. Although new transfer capacity continues to grow between New York and New England and between the Plains and Midwest, higher clean energy generation results in cost-effective transfers between other regions compared with the last group. Median transfers between the Delta and the Plains grow fivefold from 2020 and 2035, adding 20 GW of new transfer capacity. The highest median transfer capacity is found between the Mid-Atlantic and the Midwest (34 GW in 2035), likely to move low-cost clean generation in the Plains and Midwest regions to the Mid-Atlantic. Cross-interconnection transfers between Texas and its eastern neighbors grow dramatically in this scenario group. In 2040, an estimated 15 GW of new transfer capacity could be built cost effectively between Texas and the Plains and an estimated 48 GW between Texas and the Delta region.

Figure VI-10 shows the required interregional transfer capacity for the High/High scenario group in 2030, 2035, and 2040, which will not be realized nationwide without additional state and federal policies. Estimated transfer capacity between regions quadruples in the high load growth scenarios compared to the Moderate/High scenario group. An increasingly interconnected grid increases reliability, especially in high clean energy and high load futures (Bloom et al. 2020; Brown and Botterud 2020; Denholm et al. 2022a), and that is reflected in these results of increased sharing among all regions. Transfer capacities between the Midwest, Plains, and their adjacent neighbors dominate in this scenario group, as increased access to low-cost generation in the middle of the country becomes more important to meet high demand. Increased transfers between the Eastern and Western Interconnections also grow considerably in this scenario group.



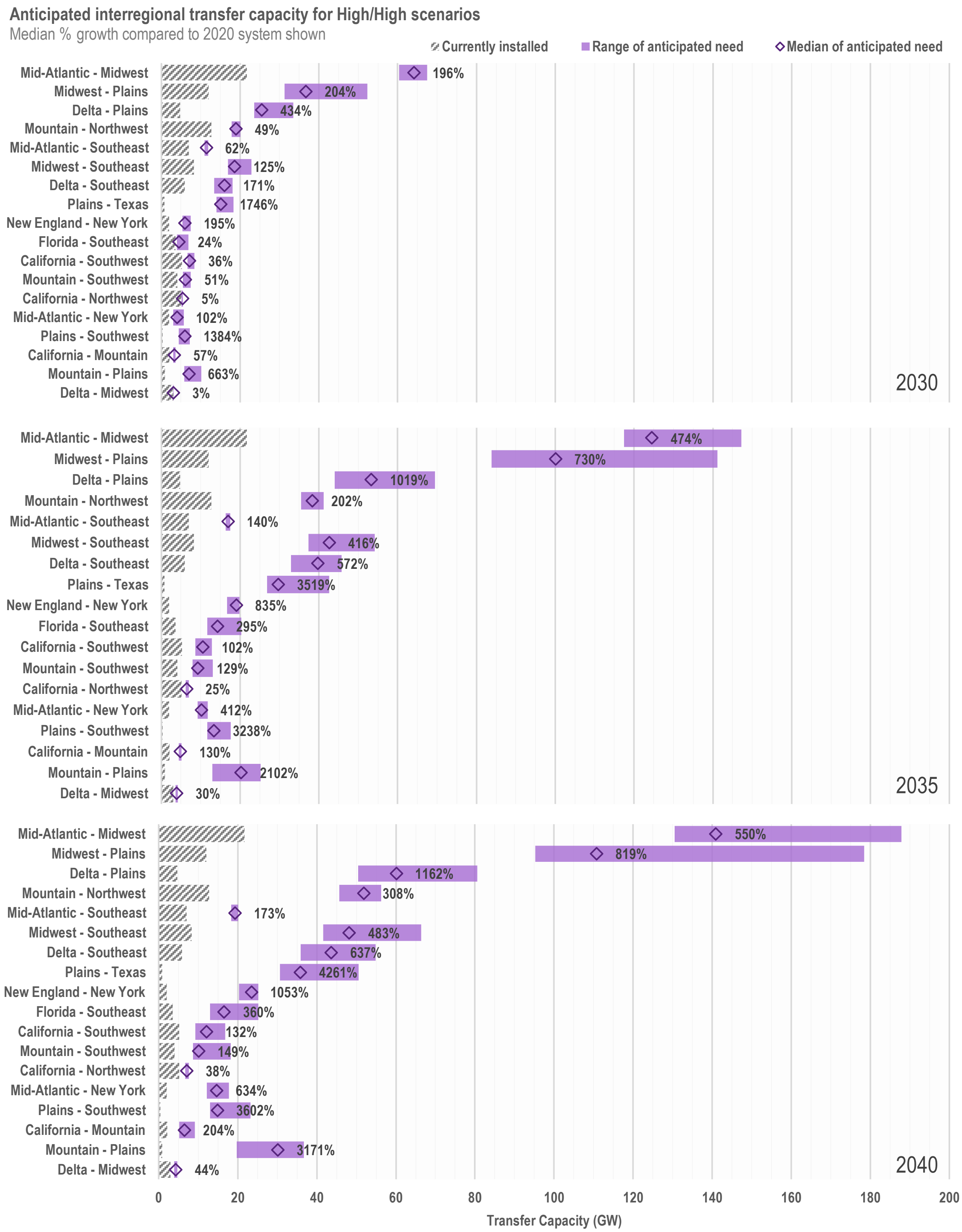
Note: New transfer capacity relative to the 2020 system is shown for all regions for 2030 (top), 2035 (middle), and 2040 (bottom). Median and IQR of new transfer capacity results are shown. Currently installed transfer capacity is as pictured from Denholm et al. (2022a).

Figure VI-8. Interregional transfer capacity for all scenarios in the Moderate/Moderate scenario group.



Note: New transfer capacity relative to the 2020 system is shown for all regions for 2030 (top), 2035 (middle), and 2040 (bottom). Median and IQR of new transfer capacity results are shown. Currently installed transfer capacity is as pictured from Denholm et al. (2022a).

Figure VI-9. Interregional transfer capacity for all scenarios in the Moderate/High scenario group.



Note: New transfer capacity relative to the 2020 system is shown for all regions for 2030 (top), 2035 (middle), and 2040 (bottom). Median and IQR of new transfer capacity results are shown. Currently installed transfer capacity is as pictured from Denholm et al. (2022a).

Figure VI-10. Interregional transfer capacity for all scenarios in the High/High scenario group.

VI.e. Comparison with Utility Plans

It is instructive to consider how current transmission utility plans for additional transmission development compare with anticipated future need revealed in the capacity expansion models considered here. Transmission planning is conducted by transmission owners and regional planning organizations to identify transmission projects expected to be needed to meet reliability and other needs. In most cases, local and regional transmission planning is conducted pursuant to FERC rules and regulations that govern the planning process and require certain minimum inputs. Interregional transmission planning is not required under these rules and regulations and the transmission plans reviewed for this study typically did not include interregional transmission needs, which in some regions (e.g., California, Northwest, Delta, Mid-Atlantic, New England, and New York) make up the bulk of anticipated transmission needs. Because few interregional plans exist, we compare utility transmission plans with the within-region transmission deployment results presented in Section VI.c. above.

Additionally, the inputs and scenarios used to create utility plans may not reflect evolving clean energy or electrification goals, which would drive additional need not reflected here. Moreover, transmission plans do not alleviate transmission needs on their own or guarantee that needed facilities will be built. Therefore, even in regions where robust utility and long-range transmission plans have been adopted in line with anticipated future transmission needs, additional action may be necessary (e.g., siting and permitting efforts) to ensure those needs are met.

NERC collects data on 10-year projections of bulk power system supply, demand, and delivery as part of its annual Long-Term Reliability Assessment process (NERC 2021) and publishes these data in its Electricity Supply and Demand database (NERC 2022c). These data include the near-term transmission development plans in each NERC assessment area, most through 2032 but some into future years. All transmission projects indicated as completed, delayed, planned, or under construction in NERC (2022c) are counted as "utility plans" for each region.

In addition, conceptual projects were considered from many of the long-term or public policy plans published by some of the regional transmission planning organizations,[60] shown in Table VI-4, which are not yet captured in the NERC Energy Supply and Demand database. The transmission projects included in these plans are at different stages of development; some have been approved by the transmission planning organizations' boards and development activities are underway, while others are hypothetical lines used for preliminary engineering analysis. It is possible that not all these conceptual projects will be built, and those that are built may not be in service by 2035. Comparing both the established utility plans and the conceptual, long-term projects against the capacity expansion modeling results provides insight into the general trajectory of transmission planning and development in each region against the anticipated

[60] Here, transmission planning organizations include the FERC Order 1000 regions and ERCOT. The scope of long-term transmission plans considered is limited to only to those published by these regional entities and not all local transmission utility plans—such as integrated resource plans—to keep the scope manageable.

need.[61] Not all of the FERC Order 1000 regional planning organizations have conducted such long-term or public policy plans in recent years.

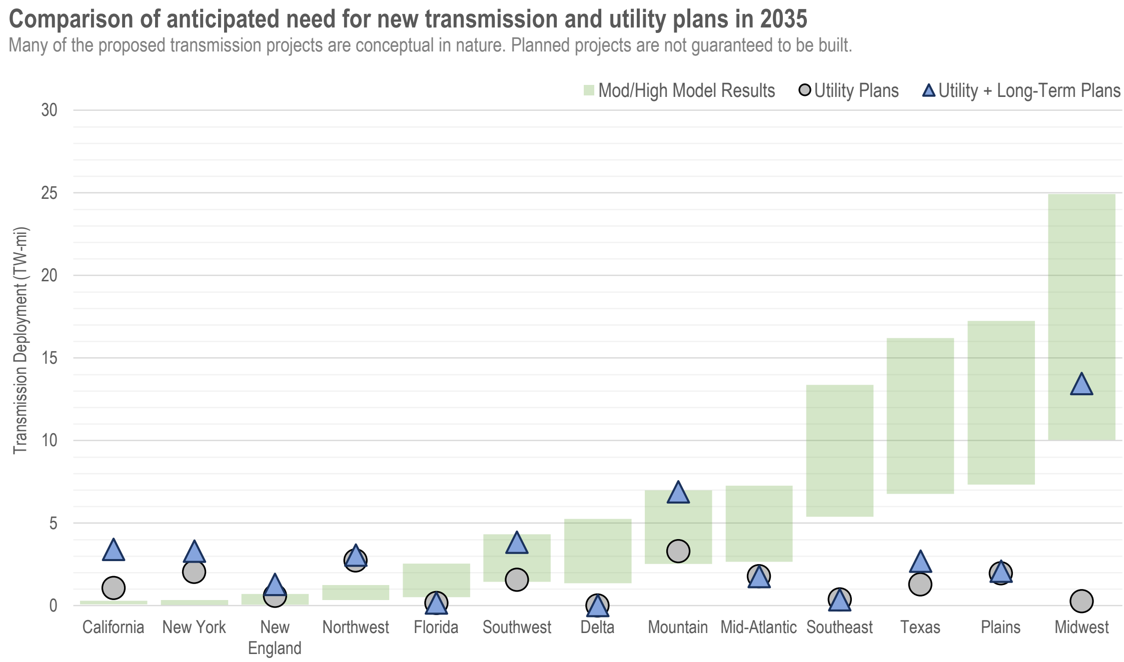
The utility plans as captured by NERC (2022c) of developers in each region meet or exceed the anticipated 2035 transmission need of the Moderate/High scenario group in the California, New York, New England, Northwest, and Mountain regions. The utility plans in the Southwest and Midwest regions also meet the anticipated 2035 need when considering long-term and public policy transmission plans, although some included projects may not yet be approved or placed in service by 2035. Considered transmission plans in all other regions—the Florida, Delta, Mid-Atlantic, Southeast, Texas, and Plains regions—do not meet this anticipated need.

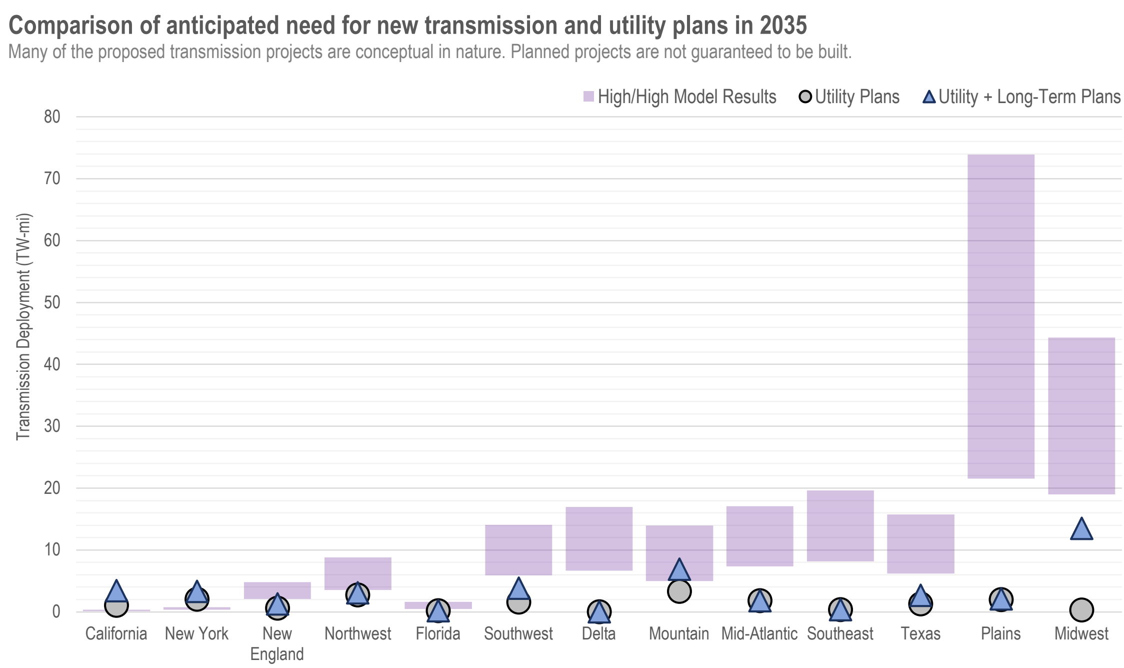
Many of the states and electric utilities in the aforementioned regions where existing utility and long-term plans exceed anticipated 2035 need under Moderate/High scenario group assumptions have decarbonization and load growth policies more in line with the High/High scenario group assumptions (NRRI 2021). When compared with results from the 2035 High/High scenario group—as shown in the bottom panel of Figure VI-7—only long-term plans in the California, New York, and Mountain regions continue to meet the anticipated transmission need. Several regions may need to develop additional transmission plans to meet their established decarbonization goals.

Table VI-5. Transmission projects from recent long-term and public policy transmission plans published by several transmission planning organizations.

Organization	Long-Term/Public Policy Transmission Plan	Included Project Category	Reference
CAISO	20-Year Transmission Outlook	• SB100 July 22 workshop projects • Other relevant projects • ISO system transmission development • Offshore wind transmission development	CAISO 2022b
ERCOT	Long-Term West Texas Export Study	• Option 1 conceptual portfolio	ERCOT 2022b
ISO-NE	2050 Transmission Study: Solution Development Update Dec 2022	• Primary Solution Set: Preliminary overhead line rebuilds • Primary Solution Set: Boston area preliminary solutions	ISO-NE 2022b
ISO-NE	2050 Transmission Study: Solution Development Update Apr 2023	• Primary Solution Set: Vermont preliminary solutions • Primary Solution Set: North–South preliminary solutions • Primary Solution Set: Boston import preliminary solutions	ISO-NE 2023
MISO	MTEP21 Report Addendum: Long-Range Transmission Planning Tranche 1	• LTRP Tranche 1 Portfolio	MISO 2022a
MISO	Long-Range Transmission Plan: Tranche 2	• Draft hypothesis transmission set	MISO 2022b
MISO-SPP	Joint Targeted Interconnection Queue	• JTIQ portfolio	MISO and SPP 2022
NorthernGrid	Economic Study Request: Offshore Wind in Oregon	• Conceptual I-5 corridor connectivity improvements • Conceptual 500 kV loop solution	NorthernGrid 2023
NYISO	2021–2040 System & Resource Outlook	• Public Policy transmission projects • Road to 2040 policy case projects	NYISO 2022a

[61] Neither the NERC Electricity Supply and Demand database (NERC 2022c) nor the long-term transmission plans considered here make up an exhaustive list of all transmission projects currently in development. Values presented are estimates based on readily available data.



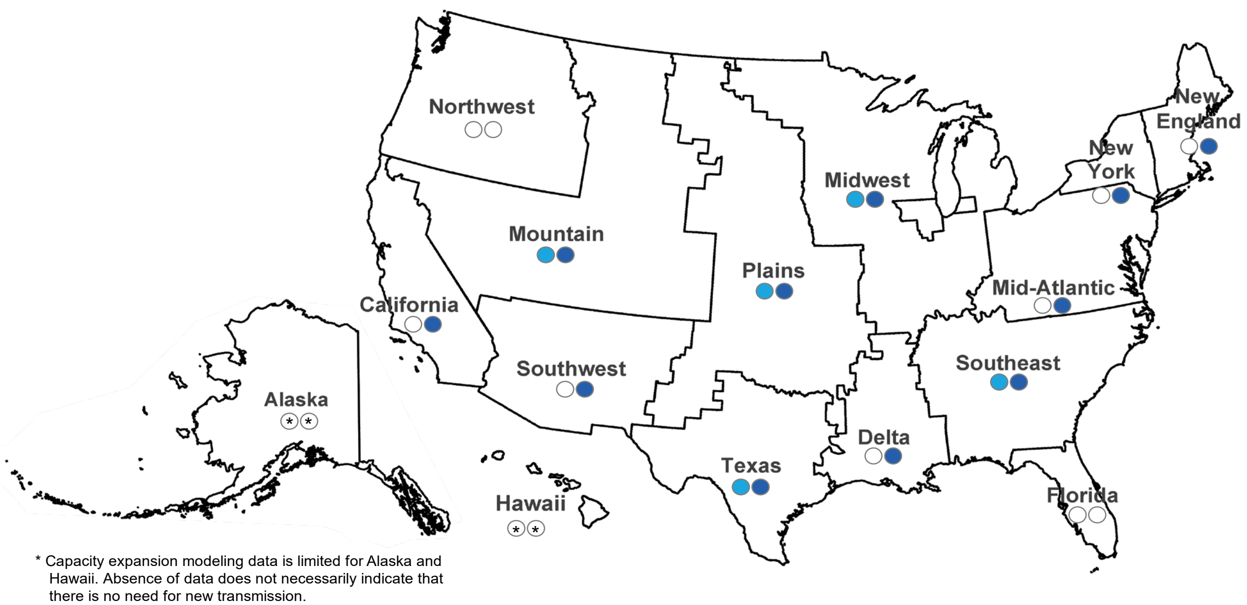


Sources: Utility plan data includes all projects that have been completed, delayed, planned, and under construction above 100 kV from North American Electric Reliability Corporation (NERC 2022c). Long-term plan data from California Independent System Operator (CAISO 2022b), Electric Reliability Council of Texas, Inc (ERCOT 2022b), ISO New England (ISO-NE 2022b), (ISO-NE 2023), Midcontinent Independent System Operator (MISO 2022a), (MISO 2022b), MISO and Southwest Power Pool (MISO and SPP 2022), NorthernGrid (NorthernGrid 2023), and New York Independent System Operator (NYISO 2022a).

Figure VI-11. Comparison of utility transmission development plans with interquartile range of capacity expansion modeling results for the Moderate/High (top) and High/High (bottom) scenario groups in 2035.

VI.f. Conclusions and Summary of Future Needs Identified through Capacity Expansion Model Analysis

Figure VI-12 summarizes findings of anticipated transmission needs by geographic region as determined by the Section VI national capacity expansion modeling results analysis. The different color circles located on the map of Figure VI-12 (top) correspond with the transmission needs listed in the dashboard (bottom).



Region

Anticipated Need	California	Northwest	Mountain	Southwest	Texas	Plains	Midwest	Delta	Southeast	Florida	Mid-Atlantic	New York	New England	Alaska	Hawaii
Meet future generation & demand with within-region transmission			●		●	●	●		●					*	*
Meet future generation & demand with interregional transfer capacity	●		●	●	●	●	●	●	●		●	●	●	*	*

Source: See the Supplemental Material for supporting references and methodology.

Note: Transmission need identified for geographic regions with Moderate/High scenario within-region or interregional transmission growth >50% in 2035 relative to 2020 levels.

Figure VI-12. Summary of future transmission needs identified in Section VI Moderate/High scenario group analysis by geographic region.

Increased transmission deployment helps regions meet growing demand needs reliably and cost effectively by connecting supply to demand. Increased transfer capacities between regions enables regions to share electricity effectively, improving system reliability and resilience and providing access to low-cost clean energy that may be generated far from load centers (Brinkman et al. 2021; Brown and Botterud 2020). Several different generation technologies will contribute to meeting the Nation’s growing electricity and clean energy demands. Which generation technologies are built, and where, will be driven by market changes, policy decisions, and social and geopolitical concerns. The analysis of capacity expansion modeling work presented in this Needs Study shows that all combinations of new generation will require increased transmission deployment to remove expected constraints and congestion that would negatively impact consumers and bring new generation to market, but to differing degrees. Capacity expansion modeling studies help quantify the range of new transmission needed to meet future demand.

Capacity expansion modeling shows within-region transmission capacity-mile deployment across all contiguous U.S. regions needs to increase 14% by 2030 and 24% by 2040 (median results) to meet a future with moderate load and clean energy growth. The future power system described by this scenario group has less load and clean energy growth than that projected to be enabled by state and federal laws enacted since 2021. Regions in greatest need of cost-effective transmission growth are those in the middle of the country, including the Texas, Mountain, Plains, and Midwest regions.

Interregional transfer capacity needs under these moderate scenario conditions are similar, needing to grow 14% by 2030 (median 16 GW) and 34% by 2040 (median 38 GW) nationally. Increased transfer capacity among neighbors in the Eastern Interconnection show that cost savings and reliability benefits can be realized for regions sharing electricity, even in moderate growth futures.

In future scenarios with moderate load but high clean energy assumptions—in line with the future power sector enabled by all currently enacted laws, including the IIJA and the IRA—both transmission deployment and transfer capacities need to increase nationwide. In these moderate load and high clean energy growth futures enabled by the IIJA and IRA, median model results suggest **54,500 GW-mi of new within-region transmission will be needed nationwide by 2035** to meet the scenario conditions of this group, a 64% increase from today's transmission system. Regions in greatest need of transmission growth are the Southeast, Texas, Plains, and Midwest.

Total median interregional transfer capacities across the contiguous United States are nearly 125 GW for scenarios with moderate load and high clean energy growth assumptions, a fivefold increase from scenarios with similar load assumptions but lower clean energy growth assumptions. Several regions would benefit from increased connectivity with their neighbors as clean energy deployment increases to over 80% annual generation. Studies show a large growth in transfer capacity between all regions adjacent to the Plains, including across the three interconnections. Large amounts of low-cost generation potential exist in the middle of the country and accessing this generation through increased transmission is shown to be cost-effective for neighboring regions.

The need for transmission growth is even greater in future scenarios that have both high load and high clean energy assumptions. The range of deployment results in this scenario group is also large, highlighting that the mix of generation and power sector technologies that enable both high load and clean energy growth vary significantly in their needs for additional transmission support. In 2030, median results suggest 33,200 GW-mi of new within-region transmission—a nearly 40% increase of today's system—is needed to meet the demands of these scenarios. By 2040, new within-region transmission deployment need is projected to be

123,000 GW-mi (median), nearly one and a half times the size of today's transmission system. The value in sharing energy on an interregional basis continues to increase in future scenarios with high demand and clean energy growth. Median study results anticipate new interregional transfer capacity needs of 152 GW in 2030 (139% growth compared to today's system) and 510 GW in 2040 (467% growth) nationwide.

VII. Process for Preparing the 2023 National Transmission Needs Study

This section reviews the process the Department followed to prepare the 2023 National Transmission Needs Study. It describes the Department's consultation with states, Tribes, and regional entities pursuant to Section 216(a) of the FPA.

As directed by the FPA, the Department consulted with states, Tribes, and regional entities in preparing this study from July through November 2022. Consultation took the form of circulating a notification letter to give entities at least 30 days' notice that the "consultation draft" would be sent to them for review and feedback, then subsequently distributing the consultation draft of the National Transmission Needs Study to each state (including points of contact from state energy offices, governors' offices, utility commissions chairs, and state public utility commission groups for multistate RTOs/ISOs), Tribes, and regional entities (including transmission reliability and planning entities) in the United States, along with an invitation to provide written comment on the draft or to meet with DOE staff, in person or by phone, to convey comments. In addition, DOE briefed the states, Tribes, and regional entities via a series of six webinars on the consultation draft, with one webinar open to all consultation draft recipients and the other five targeted at each entity type in partnership with a convening group to help with amplification of the webinar (e.g., DOE partnered with the National Association of State Energy Offices for the webinar targeted at state energy offices). Appendix A-1 of the public draft of this Needs Study[62] contains a list of 20 entities that submitted written or verbal comments on the consultation draft of the study, and an overview summary of the comments received.

The Department made substantial revisions based on consultation comments ahead of releasing an updated Draft for Public Comment in February 2023. Appendix A-2 of the public draft contains a detailed comment matrix that documents each individual comment received and the manner in which the Department resolved each comment. Department staff held a public webinar, which accompanied the public draft in March 2023. A 9-week public comment period was open from February to April 2023. Departmental staff met with all commenting entities who requested an audience to discuss their comments in greater detail. Table VII-1 lists the 58 entities who submitted public comments. A compilation of received public comments is available online.[63] This Final National Transmission Needs Study reflects changes DOE made in response to public comments. A summary of the comments received during the public comment period and the Department's resolution can be found in Appendix B.

[62] DOE. 2023. National Transmission Needs Study: Draft for Public Comment. Feb. 2023. Available at https://www.energy.gov/sites/default/files/2023-02/022423-DRAFTNeedsStudyforPublicComment.pdf.
[63] DOE. 2023. Comments – National Transmission Needs Study Public Draft – Spring 2023. Available at: https://www.energy.gov/sites/default/files/2023-07/072423_Needs-Study_Public-Draft-Comments-Compiled_Spring-2023.pdf.

Table VII-1. List of commenting entities.

Commenting Entities		
Advanced Energy Group	Data Center Coalition	National Grid
Advanced Energy United	DataCapable	National Hydropower Association
AES Corporation	Econwerks LLC	New Jersey Board of Public Utilities
Alaska Energy Authority	Edison Electric Institute	New York Transmission Owners
Alliant Energy	Electric Reliability Council of Texas	North Carolina Utilities Commission
American Chemistry Council	Environmental Defense Fund	Northern California Tribal Chairpersons Association
American Clean Power Association	Federation of American Scientists	PJM Interconnection
American Council on Renewable Energy	Gallatin Power	Public Services Enterprise Group Inc.
American Electric Power Service Corporation	Grid United	Seattle City Light
Americans for a Clean Energy Grid	Hydro-Québec	Southeast Public Interest Groups
Arizona Municipal Power Users' Association and Irrigation and Electrical Districts Association of Arizona	International Transmission Company Holdings Corporation	Southern Renewable Energy Association
Association for Modern Powerlines	ISO New England Inc.	Sponsors of the Southeastern Regional Transmission Planning Process
Avangrid	Janice Cooper	Transmission Developers Inc New England
Blue Lake Rancheria Tribe	Juneau Hydropower	Utah Public Lands Coordinating Office
Center for Biological Diversity	Keryn Newman	Vijayasekar Rajsekar
Clean Energy Buyers Association	LineVision	Western Electricity Coordinating Council
Columbia River Treaty Power Group	Martyn Roetter	William Driscoll
Con Edison	Monitoring Analytics	Working for Advanced Transmission Technologies Coalition
Dana Siler	National Electrical Manufacturers Association	Xcel Energy
(Filed jointly) Natural Resources Defense Council, Sustainable FERC Project, RMI, Earthjustice, Sierra Club, National Wildlife Federation, Southern Environmental Law Center, Western Resource Advocates, Montana Environmental Information Center, National Audubon Society, and Alliance for Affordable Energy		

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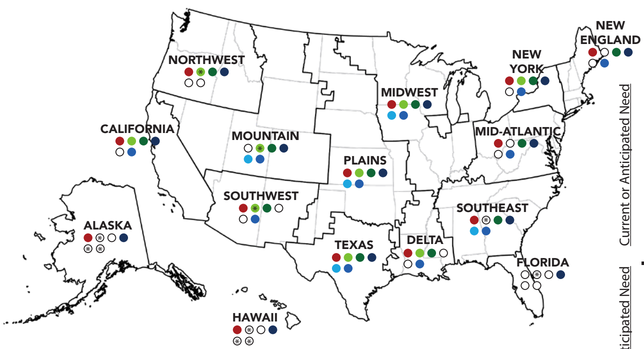
Appendix A: National and Regional Fact Sheets

FACT SHEET

2023 NATIONAL TRANSMISSION NEEDS STUDY

UNITED STATES

The U.S. Department of Energy's Grid Deployment Office (GDO) released the National Transmission Needs Study ("Needs Study") in October 2023. The Needs Study is the Department's **triennial state of the grid** report. The Needs Study identifies transmission needs and provides information about current and anticipated future capacity constraints and congestion on the Nation's electric transmission grid. In this fact sheet, we highlight the transmission needs across the United States. The Needs Study provides further detail on the benefits of transmission that could be realized throughout the country.



	Region:	California	Northwest	Mountain	Southwest	Texas	Plains	Midwest	Delta	Southeast	Florida	Mid-Atlantic	New York	New England	Alaska	Hawaii
Current or Anticipated Need	Improve reliability & resilience	●	●		●	●	●	●	●	●		●	●	●	●	●
	Alleviate congestion & unscheduled flows	●	●*	●*	●	●	●	●	●	*	*		●		*	*
	Alleviate transfer capacity limits between neighbors	●	●	●	●	●	●	●	●	●		●	●	●		
	Deliver cost-effective generation to meet demand	●	●	●		●	●	●		●	●	●	●	●	●	●
Anticipated Need	Meet future generation & demand with within-region transmission			●		●	●	●		●					*	*
	Meet future generation & demand with interregional transfer capacity	●		●	●	●	●	●	●	●		●	●	●	*	*

**Wholesale market price data is limited for non-RTO/ISO regions and capacity expansion modeling data is limited for Alaska and Hawaii. Absence of data does not necessarily indicate that there is no need for new transmission.*

FINDINGS OF TRANSMISSION NEED ACROSS THE UNITED STATES

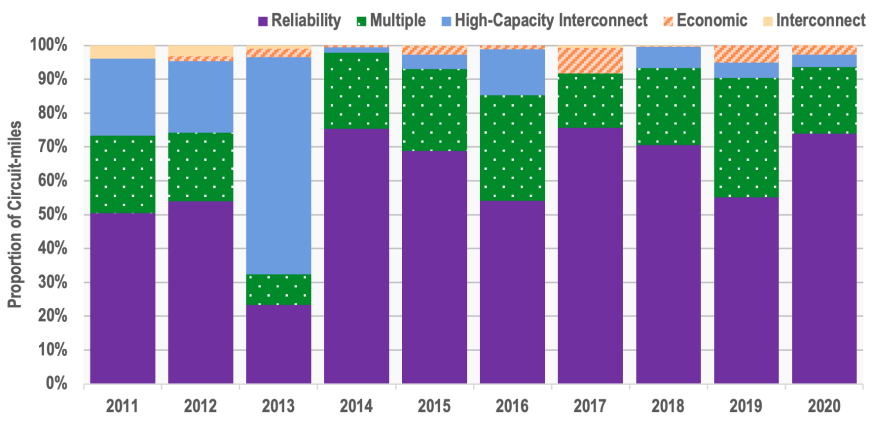
- **Improve reliability and resilience. Nearly all regions** in the United States would gain improved reliability and resilience from additional transmission investments. Some regions have acute reliability and resilience needs which additional transmission deployment can address.
- **Alleviate congestion and unscheduled flows.** Regions with historically high levels of within-region congestion—the **Northwest, Mountain, Texas, and New York** regions in particular—as well as regions with unscheduled flows that pose reliability risks—**California, Northwest, Mountain, and Southwest** regions—need additional, strategically placed transmission deployment to reduce this congestion.
- **Alleviate transfer capacity limits between regions.** Historically, the data assessed show a need for transmission to alleviate transmission constraints that prevent moving electricity across the interconnection seams—**between the Mountain and Plains** regions and **between Texas and all its neighbors** (Southwest, Plains, and Delta regions). Similar needs are also found **between the Plains and the Midwest and Delta** regions, its two eastern neighbors.
- **Deliver cost-effective generation to meet demand.** Areas of several regions endure consistently high prices, most notably in the **Plains, Midwest, Mid-Atlantic, New York, and California**. Additional transmission to bring cost-effective generation to demand in these high-priced locations would help lower prices.
- **Meet future generation and demand with additional within-region transmission.** The clean energy transformation, evolving regional demand, and increasingly extreme events must all be accommodated by the future power grid. Significant transmission deployment is needed as soon as 2030 in the **Plains, Midwest, and Texas** regions. By 2040, large deployments will also be needed in the **Mountain, Mid-Atlantic, and Southeast**.
- **Meet future generation and demand with additional interregional transmission transfer capacity.** The same power sector characteristics are also driving increased need in interregional transmission deployment. By 2040 there is a significant need for new interregional transmission between **nearly all regions**.

HELPFUL LINKS

- **Read the full study at www.energy.gov/gdo/national-transmission-needs-study**
- **Contact GDO with additional questions: transmission@hq.doe.gov**

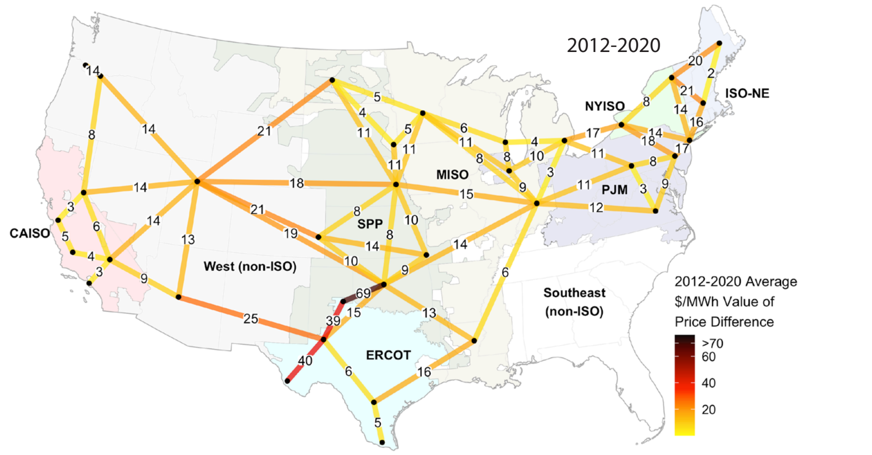
FINDINGS AT A GLANCE

Proportion of national circuit-miles of new or rebuilt transmission lines (≥100kV) energized between 2011–2020 by project driver.



The proportion of overall transmission circuit-miles installed to address specific **system reliability needs** has grown with time, from 44% in 2011 to 74% in 2020.

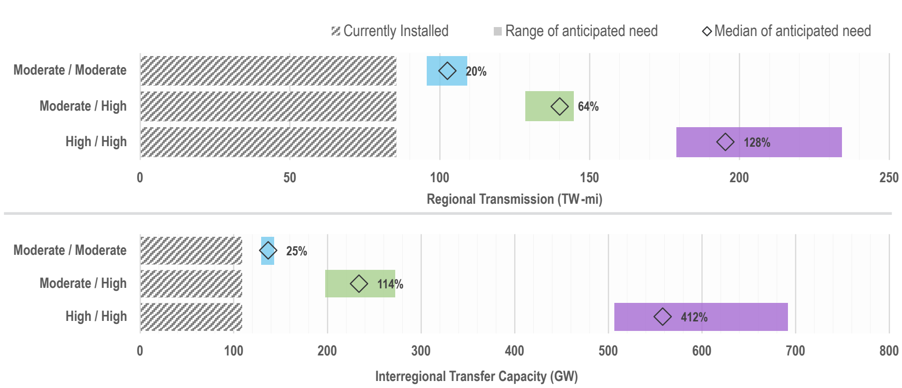
Congestion value of hypothetical transmission links between select zonal nodes within and across regions.



Note: Wholesale market price data is limited for non-RTO/ISO regions. Absence of data does not necessarily indicate that there is no need for transmission to alleviate congestion and/or unscheduled flows in non-RTO/ISO regions. Findings organized using geographic region nomenclature as described in the Needs Study.
Source: D. Millstein, et al. (2022)

Wholesale market price differentials demonstrate the **highest value of new interregional transmission** exists **across the three electrical interconnections**.

Within-region transmission and interregional transfer capacity need across the United States in 2035
Anticipated need for three future scenario groups labeled as __ load / __ clean energy growth.
Median % growth compared to 2020 system shown.



There is an **increasing need for both within-region and interregional transfer capacity by 2035** as consumer load and clean energy generation grows nationwide. These needs also grow with time.

Median 2035 capacity expansion modeling results for each scenario group from the Needs Study highlighted.

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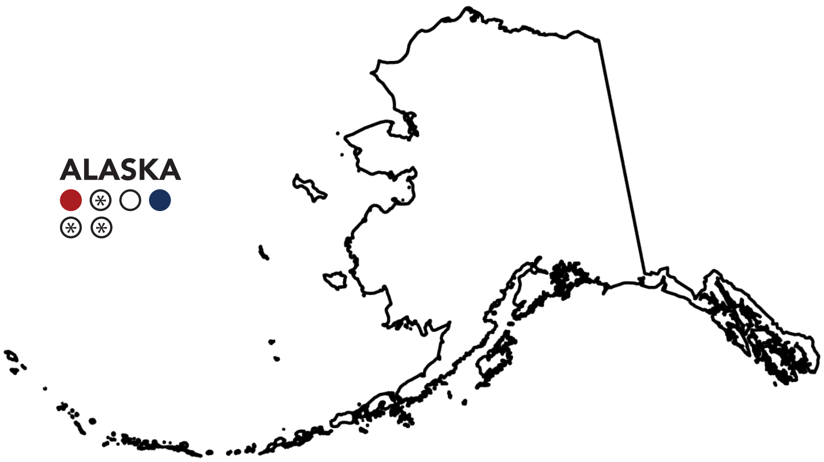
FACT SHEET

2023 NATIONAL TRANSMISSION NEEDS STUDY

ALASKA

The U.S. Department of Energy's Grid Deployment Office (GDO) released the National Transmission Needs Study ("Needs Study") in October 2023. The Needs Study is the Department's **triennial state of the grid** report. The Needs Study identifies transmission needs and provides information about current and anticipated future capacity constraints and congestion on the Nation's electric transmission grid. In this fact sheet, we highlight the transmission needs of Alaska. The Needs Study provides further detail on the benefits of transmission that could be realized throughout in the country.



	Need	
Current or Anticipated Need	Improve reliability & resilience	●
	Alleviate congestion & unscheduled flows	*
	Alleviate transfer capacity limits between neighbors	
	Deliver cost-effective generation to meet demand	●
Anticipated Need	Meet future generation & demand with within-region transmission	*
	Meet future generation & demand with interregional transfer capacity	*

**Wholesale market price data is limited for non-RTO/ISO regions and capacity expansion modeling data is limited for Alaska. Absence of data does not necessarily indicate that there is no need for new transmission.*

FINDINGS OF TRANSMISSION NEED IN ALASKA

- **Improve reliability and resilience.** Anticipated generation retirements in Alaska's northern Railbelt region are expected to require capacity replacement from power purchase agreements with southcentral Railbelt utilities and new renewable resources installations. Transmission upgrades to deliver needed capacity to the northern Railbelt region would reduce existing capacity constraints negatively impacting the Alaska Intertie. Similarly, planned generation capacity increases on the Kenai Peninsula in the southern Railbelt region are anticipated to require transmission upgrades to reduce constraints and increase capacity exports on the Kenai Intertie. Further, deployment of additional transmission paths parallel to constrained single transmission lines—particularly near the interties and certain areas of the southcentral Railbelt region—would help reduce the need for load shedding following contingency events.
- **Deliver cost-effective generation to meet demand.** Outside of the Railbelt service region, rural Alaskan communities are served largely by standalone microgrids. Additional transmission between isolated Alaskan communities served by rural utilities, as well as increased rural utility interconnection with the Railbelt transmission system where feasible, would help accommodate higher levels of renewable capacity and help supply cost-effective generation in areas that rely on higher-cost, imported diesel fuel.

HELPFUL LINKS

- **Read the full study at www.energy.gov/gdo/national-transmission-needs-study**
- **Contact GDO with additional questions: transmission@hq.doe.gov**

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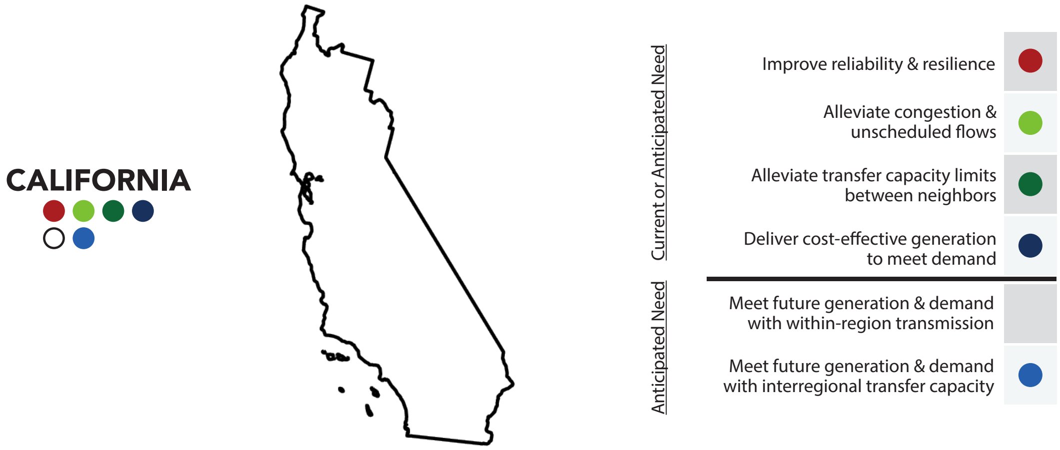
2023 NATIONAL TRANSMISSION NEEDS STUDY

CALIFORNIA

The U.S. Department of Energy's Grid Deployment Office (GDO) released the National Transmission Needs Study ("Needs Study") in October 2023. The Needs Study is the Department's **triennial state of the grid** report. The Needs Study identifies transmission needs and provides information about current and anticipated future capacity constraints and congestion on the Nation's electric transmission grid. In this fact sheet, we highlight the transmission needs of California. The Needs Study provides further detail on the benefits of transmission that could be realized throughout the country.



FINDINGS OF TRANSMISSION NEED IN CALIFORNIA

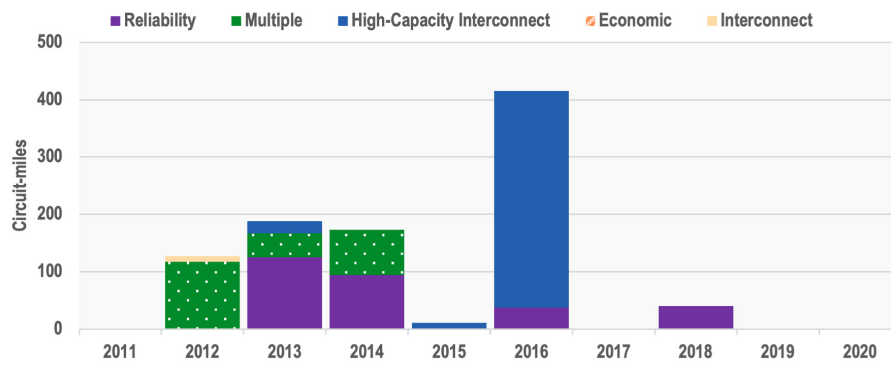
- **Improve reliability and resilience.** California faces risk of load curtailment during extreme weather events, wildfires, and earthquakes, particularly as the region becomes increasingly reliant on variable energy resources and energy imports to meet peak demand. Additional transmission upgrades would reduce risks to electricity reliability from extreme events. Further, California is anticipated to experience reserve margin shortfalls in the next few years and additional transmission capacity would accommodate new and diverse resource integration and anticipated generation retirements.
- **Alleviate congestion and unscheduled flows.** Unscheduled flows persist on Qualified Path 66 located at the intersection of the Northwest, California, and Mountain regions; additional transmission deployment would alleviate these unscheduled flows.
- **Alleviate transfer capacity limits between California and its neighbors.** High congestion value of interregional transmission from 2012–2020 exists between California and the Mountain regions, with an average marginal value of transmission equal to $14/MWh. A high congestion value indicates that increased transmission between the regions would reduce system congestion and constraints.
- **Deliver cost-effective generation to meet demand.** High-priced areas persist in northern and southern coastal areas and additional transmission to bring cost-effective generation to demand would help reduce these prices. California is also anticipated to require higher levels of new generation and demand resources aligned with state laws, including out-of-state wind and solar generation, and additional transmission capacity would help accommodate the necessary resources.
- **Meet future generation and demand with additional interregional transfer capacity.** It is anticipated that California will need between 1.5 and 2.3 GW of additional transfer capacity with the Mountain region in 2035 (median of 1.9 GW, an 88% increase relative to the 2020 system) to meet moderate load growth and high clean energy growth future scenarios. Smaller additional transfer capacity between California and the Southwest (median value of 0.3 GW) and Northwest (median value of 0.1 GW) regions may also be required.

HELPFUL LINKS

- **Read the full study at www.energy.gov/gdo/national-transmission-needs-study**
- **Contact GDO with additional questions: transmission@hq.doe.gov**

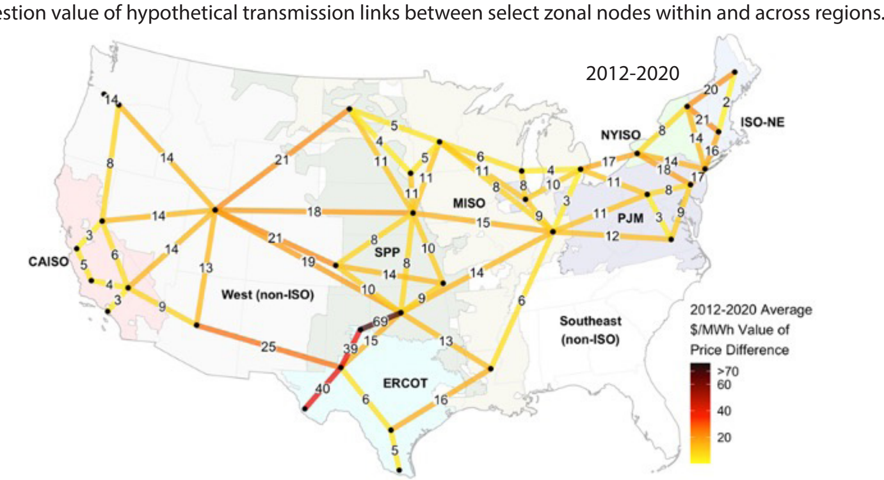
FINDINGS AT A GLANCE

Circuit-miles of new or rebuilt transmission lines (≥100kV) energized between 2011–2020 by project driver.



Transmission projects energized over the last decade in California were installed to **address a diversity of concerns**. Projects installed in **2016 were largely high-capacity** (>230kV) projects to interconnect generation.

Congestion value of hypothetical transmission links between select zonal nodes within and across regions.

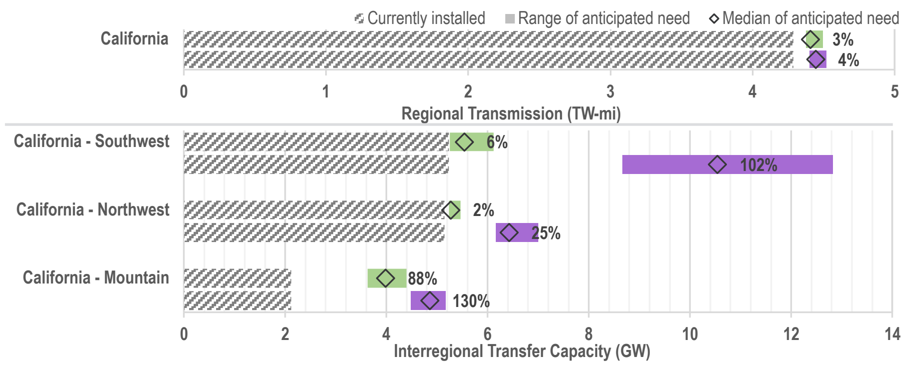


Note: Wholesale market price data is limited for non-RTO/ISO regions. Absence of data does not necessarily indicate that there is no need for transmission to alleviate congestion and/or unscheduled flows in non-RTO/ISO regions. Findings organized using geographic region nomenclature as described in the Needs Study.
Source: D. Millstein, et al. (2022)

Wholesale market price differentials demonstrate a **high value of new interregional transmission** exists **between California and the Mountain region**.

The average marginal value of transmission between California and the Mountain region from 2012–2020 is equal to $14/MWh.

Within-region transmission and interregional transfer capacity need for California in 2035
Range of new transmission need for future scenarios with moderate load and high clean energy growth (green, top for each region) and high load and high clean energy growth (purple, bottom). Median % growth compared to 2020 system shown.



Capacity expansion modeling results for the Moderate/High scenario group suggest an anticipated need of **0.12 TW-miles of new within-region transmission by 2035** (3% growth relative to 2020) and **1.9 GW of new interregional transfer capacity with the Mountain region by 2035** (88% growth relative to 2020).

Median 2035 capacity expansion modeling results for Moderate/High scenario group.

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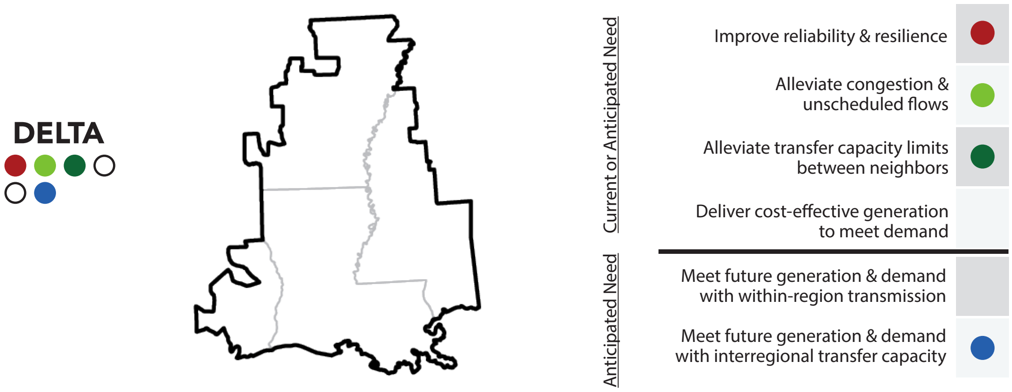
FACT SHEET

2023 NATIONAL TRANSMISSION NEEDS STUDY

DELTA REGION

The U.S. Department of Energy's Grid Deployment Office (GDO) released the National Transmission Needs Study ("Needs Study") in October 2023. The Needs Study is the Department's **triennial state of the grid** report. The Needs Study identifies transmission needs and provides information about current and anticipated future capacity constraints and congestion on the Nation's electric transmission grid. In this fact sheet, we highlight the transmission needs of the Delta region. The Needs Study provides further detail on the benefits of transmission that could be realized throughout the country.



FINDINGS OF TRANSMISSION NEED IN THE DELTA REGION

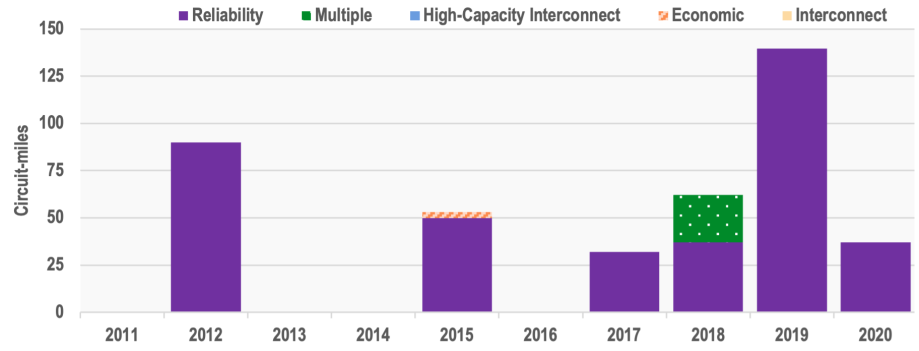
- **Improve reliability and resilience.** Generation retirements over the next few years are anticipated to result in capacity shortfalls without additional generation or import transfer capability additions. Additional regional or interregional transmission to access diverse generation resources would help ensure resource adequacy. Additional interregional transfer capacity would also bolster system resilience and mitigate load shedding during extreme weather events, as was experienced during winter storms in both 2018 and 2021. The Delta region is also susceptible to increasingly severe hurricane storm surges, which can damage transmission facilities and result in power outages.
- **Alleviate congestion and unscheduled flows.** Congestion costs in the combined Midwest and Delta regions have increased in recent years due to insufficient transmission to support wind generation and due to generation and transmission outages, including the recent impact of Hurricane Laura in the Delta region.
- **Alleviate transfer capacity limits between the Delta region and its neighbors.** High congestion value of interregional transmission from 2012–2020 exists between the Delta region and Texas, with an average marginal value of transmission equal to $16/MWh. A high congestion value indicates that additional transmission between the regions would reduce system congestion and constraints.
- **Meet future generation and demand with additional interregional transfer capacity.** It is anticipated that the Delta region will need between 10.8 and 23.8 GW of additional transfer capacity with the Plains region in 2035 (median of 19.7 GW, a 414% increase relative to the 2020 system) to meet moderate load growth and high clean energy growth future scenarios. Smaller additional transfer capacity between the Delta and Southeast region (median value of 5.1 GW) may also be required.

HELPFUL LINKS

- **Read the full study at www.energy.gov/gdo/national-transmission-needs-study**
- **Contact GDO with additional questions: transmission@hq.doe.gov**

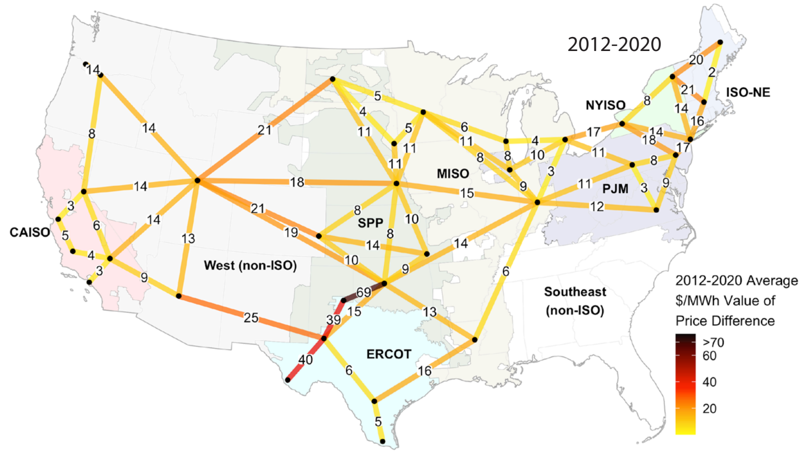
FINDINGS AT A GLANCE

Circuit-miles of new or rebuilt transmission lines (≥100kV) energized between 2011–2020 by project driver.



Transmission projects energized over the last decade in the Delta region were predominantly installed to **address reliability concerns**.

Congestion value of hypothetical transmission links between select zonal nodes within and across regions.

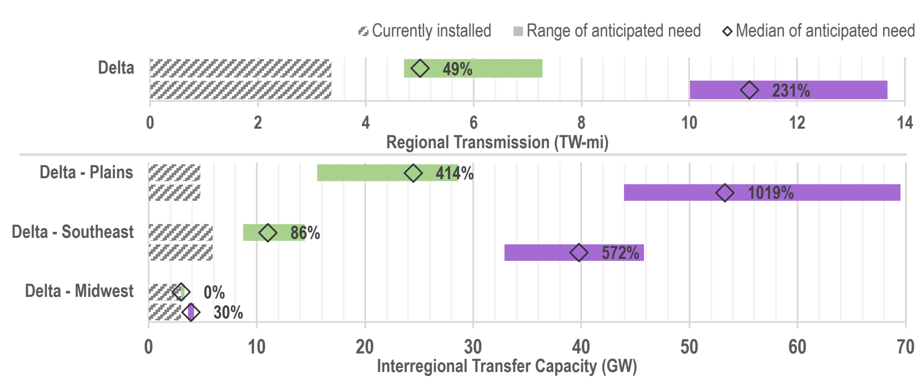


Wholesale market price differentials demonstrate a **high value of new interregional transmission** exists **between the Delta region and Texas**.

The average marginal value of transmission between the Delta region and Texas from 2012–2020 is equal to $16/MWh.

Note: Wholesale market price data is limited for non-RTO/ISO regions. Absence of data does not necessarily indicate that there is no need for transmission to alleviate congestion and/or unscheduled flows in non-RTO/ISO regions. Findings organized using geographic region nomenclature as described in the Needs Study.
Source: D. Millstein, et al. (2022)

Within-region transmission and interregional transfer capacity need for Delta in 2035
Range of new transmission need for future scenarios with moderate load and high clean energy growth (green, top for each region) and high load and high clean energy growth (purple, bottom). Median % growth compared to 2020 system shown.



Capacity expansion modeling results for the Moderate/High scenario group suggest an anticipated need of **1.7 TW-miles of new within-region transmission by 2035** (49% growth relative to 2020) and 19.7 **GW of new interregional transfer capacity with the Plains region by 2035** (414% growth relative to 2020).

Median 2035 capacity expansion modeling results for Moderate/High scenario group.

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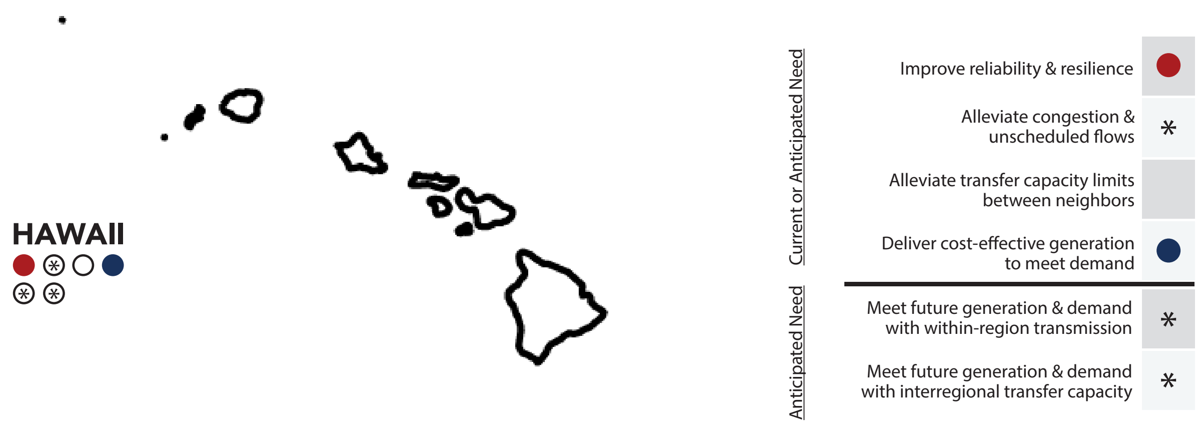
2023 NATIONAL TRANSMISSION NEEDS STUDY

HAWAII

The U.S. Department of Energy's Grid Deployment Office (GDO) released the National Transmission Needs Study ("Needs Study") in October 2023. The Needs Study is the Department's **triennial state of the grid** report. The Needs Study identifies transmission needs and provides information about current and anticipated future capacity constraints and congestion on the Nation's electric transmission grid. In this fact sheet, we highlight the transmission needs of Hawaii. The Needs Study provides further detail on the benefits of transmission that could be realized throughout in the country.



** Wholesale market price data is limited for non-RTO/ISO regions and capacity expansion modeling data is limited for Hawaii. Absence of data does not necessarily indicate that there is no need for new transmission.*

FINDINGS OF TRANSMISSION NEED IN HAWAII

- **Improve reliability and resilience.** Transmission systems on Hawaii, Lanai, Maui, Molokai, and Oahu islands are approaching capacity limitations and will require additional transmission capacity as the islands continue to integrate renewable resources through ongoing and future procurement necessary to meet state clean energy goals. Hawaii anticipates potential reliability concerns due to high levels of inverter-based renewables integration. In Kauai, system operators note the transmission system is capable of riding through a single contingency in accordance with its system voltage and frequency requirements with current generation and load levels; however, with anticipated load growth, additional transmission infrastructure would allow for a more resilient grid in the face of plausible contingency scenarios.

- **Deliver cost-effective generation to meet demand.** Transmission network expansion is critical for Hawaii, Lanai, Maui, Molokai, and Oahu islands to integrate sufficient renewable resources required for the state to reach its 100% renewable by 2045 renewable portfolio standard target.

HELPFUL LINKS

- **Read the full study at www.energy.gov/gdo/national-transmission-needs-study**
- **Contact GDO with additional questions: transmission@hq.doe.gov**

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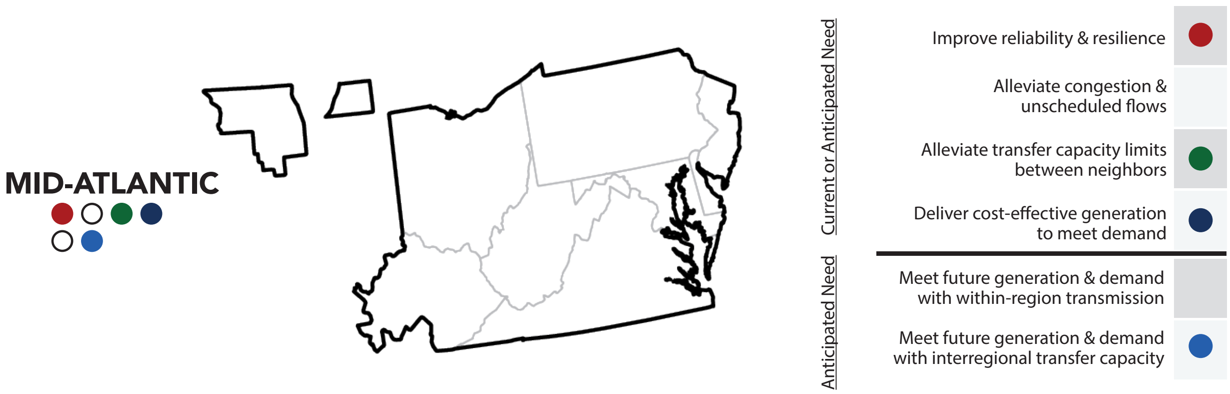
FACT SHEET

2023 NATIONAL TRANSMISSION NEEDS STUDY

MID-ATLANTIC REGION

The U.S. Department of Energy's Grid Deployment Office (GDO) released the National Transmission Needs Study ("Needs Study") in October 2023. The Needs Study is the Department's **triennial state of the grid** report. The Needs Study identifies transmission needs and provides information about current and anticipated future capacity constraints and congestion on the Nation's electric transmission grid. In this fact sheet, we highlight the transmission needs of the Mid-Atlantic. The Needs Study provides further detail on the benefits of transmission that could be realized throughout the country.



FINDINGS OF TRANSMISSION NEED IN THE MID-ATLANTIC REGION

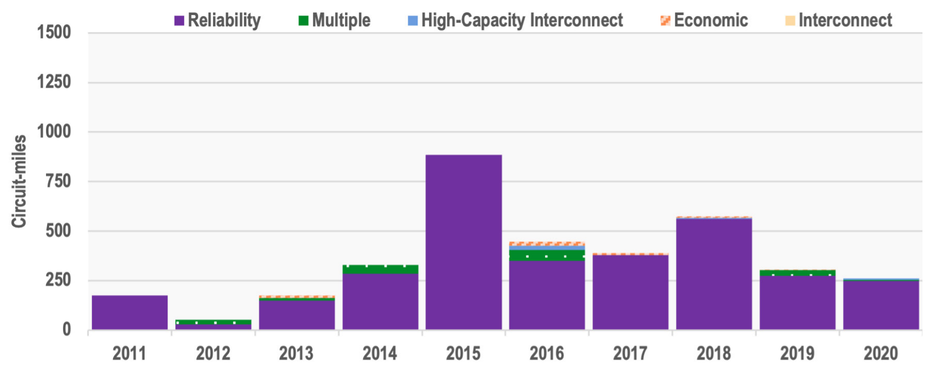
- **Improve reliability and resilience.** Reliability risks are anticipated to arise in the near-term due to electricity demand growth, thermal generator retirements, and increases in intermittent and limited-duration resource interconnection requests. Additional transmission additions and upgrades in the near-term would help maintain resource adequacy and accommodate generation loss. Additionally, stronger transmission ties with neighboring regions would help support reliability and resilience of the Mid-Atlantic system during extreme weather events, such as the recent 2018 bomb cyclone and 2020 Winter Storm Elliott events.
- **Alleviate transfer capacity limits between the Mid-Atlantic region and New York.** High congestion value of interregional transmission from 2012–2020 exists between the Mid-Atlantic region and New York, with an average marginal value of transmission equal to \$18/MWh. A high congestion value indicates that additional transmission between the regions would reduce system congestion and constraints.
- **Deliver cost-effective generation to meet demand.** High-priced areas persist in eastern Maryland, eastern Virginia, and both Maryland and Delaware portions of the Delmarva Peninsula; additional transmission to bring cost-effective generation to demand would help reduce these prices.
- **Meet future generation and demand with additional interregional transfer capacity.** It is anticipated that the Mid-Atlantic region will need between 28 and 51.7 GW of additional transfer capacity with the Midwest in 2035 (median of 33.8 GW, a 156% increase relative to the 2020 system) to meet moderate load growth and high clean energy growth future scenarios. Smaller additional transfer capacity between the Mid-Atlantic and the Southeast (median value of 6.9 GW) and New York (median value of 2.4 GW) may also be required.

HELPFUL LINKS

- **Read the full study at www.energy.gov/gdo/national-transmission-needs-study**
- **Contact GDO with additional questions: transmission@hq.doe.gov**

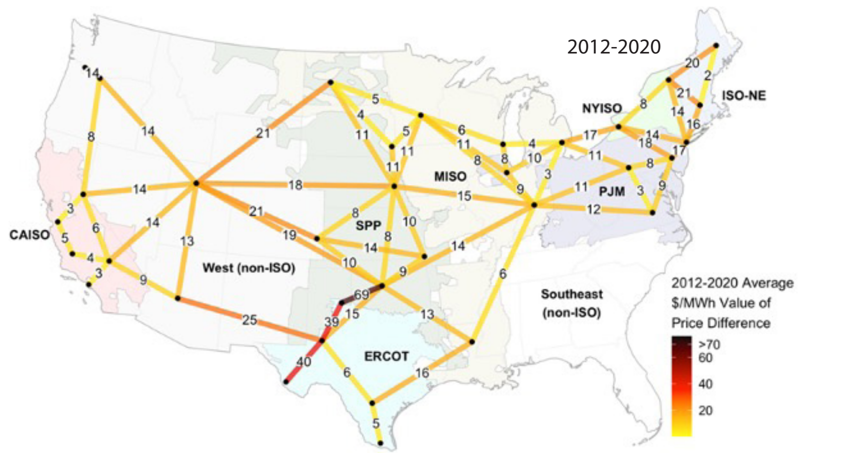
FINDINGS AT A GLANCE

Circuit-miles of new or rebuilt transmission lines (≥100kV) energized between 2011–2020 by project driver.



Transmission projects energized over the last decade in the Mid-Atlantic region were predominantly installed to **address reliability concerns**.

Congestion value of hypothetical transmission links between select zonal nodes within and across regions.

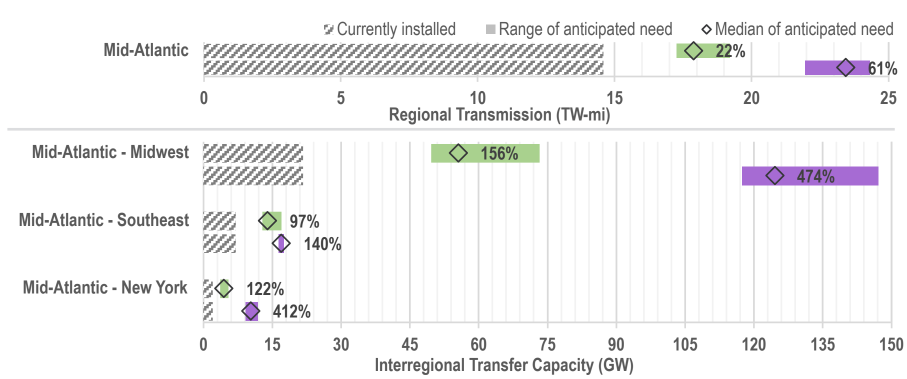


Note: Wholesale market price data is limited for non-RTO/ISO regions. Absence of data does not necessarily indicate that there is no need for transmission to alleviate congestion and/or unscheduled flows in non-RTO/ISO regions. Findings organized using geographic region nomenclature as described in the Needs Study.
Source: D. Millstein, et al. (2022)

Wholesale market price differentials demonstrate a **high value of new interregional transmission** exists **between the Mid-Atlantic region and New York**.

The average marginal value of transmission between the Mid-Atlantic region and New York from 2012–2020 is equal to $18/MWh.

Within-region transmission and interregional transfer capacity need for Mid-Atlantic in 2035
Range of new transmission need for future scenarios with moderate load and high clean energy growth (green, top for each region) and high load and high clean energy growth (purple, bottom). Median % growth compared to 2020 system shown.



Capacity expansion modeling results for the Moderate/High scenario group suggest an anticipated need of **3.3 TW-miles of new within-region transmission by 2035** (22% growth relative to 2020) and **33.8 GW of new interregional transfer capacity with the Midwest region by 2035** (156% growth relative to 2020).

Median 2035 capacity expansion modeling results for Moderate/High scenario group.

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2023 NATIONAL TRANSMISSION NEEDS STUDY

MIDWEST REGION

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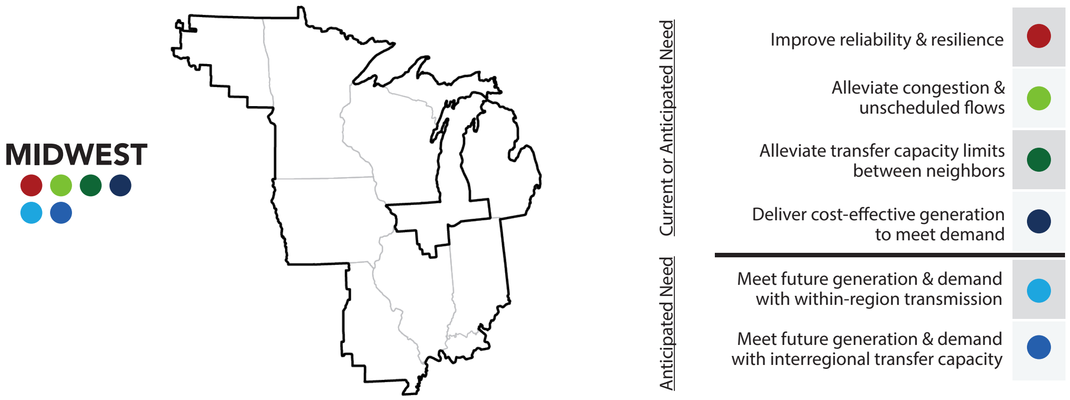


FINDINGS OF TRANSMISSION NEED IN THE MIDWEST REGION

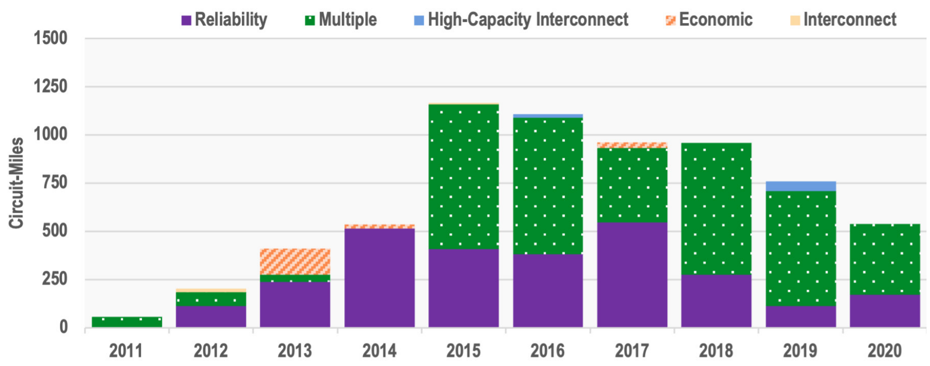
- **Improve reliability and resilience.** Generation retirements over the next few years are anticipated to result in capacity shortfalls without additional generation or import transfer capability additions. Additional regional or interregional transmission to access diverse generation resources would help ensure resource adequacy in the region. Additional interregional transfer capacity would also bolster system resilience and mitigate load shedding during extreme weather events, as was experienced during winter storms in both 2018 and 2021.
- **Alleviate congestion and unscheduled flows.** Congestion costs in the combined Midwest and Delta regions have increased in recent years due to insufficient transmission to support wind generation and due to generation and transmission outages.
- **Alleviate transfer capacity limits between the Midwest region and its neighbors.** High congestion value of interregional transmission from 2012–2020 exists between the Midwest region and New York, with an average marginal value of transmission equal to $17/MWh. Similarly high congestion values of transmission exist between the Midwest and Plains regions, ranging from $4/MWh–$15/MWh. A high congestion value indicates that additional transmission between the regions would reduce system congestion and constraints.
- **Deliver cost-effective generation to meet demand.** High-priced areas in northwestern Wisconsin and in eastern and the Upper Peninsula of Michigan persist and additional transmission to bring cost-effective generation resources to demand would help these reduce prices.
- **Meet future generation and demand with additional within-region transmission.** It is anticipated that the Midwest will need between 10 and 14.9 TW-miles of additional within-region transmission in 2035 (median 13.3 TW-miles, a 112% increase relative to the 2020 system) to meet moderate load and high clean energy growth scenarios.
- **Meet future generation and demand with additional interregional transfer capacity.** It is anticipated that the Midwest will need between 28 and 51.7 GW of additional transfer capacity with the Mid-Atlantic region in 2035 (median of 33.8 GW, a 156% increase relative to the 2020 system) to meet moderate load growth and high clean energy growth future scenarios. Smaller additional transfers between the Midwest and the Plains (median value of 21.1 GW) and Southeast (median value of 4.5 GW) regions may also be required.

HELPFUL LINKS

- **Read the full study at www.energy.gov/gdo/national-transmission-needs-study**
- **Contact GDO with additional questions: transmission@hq.doe.gov**

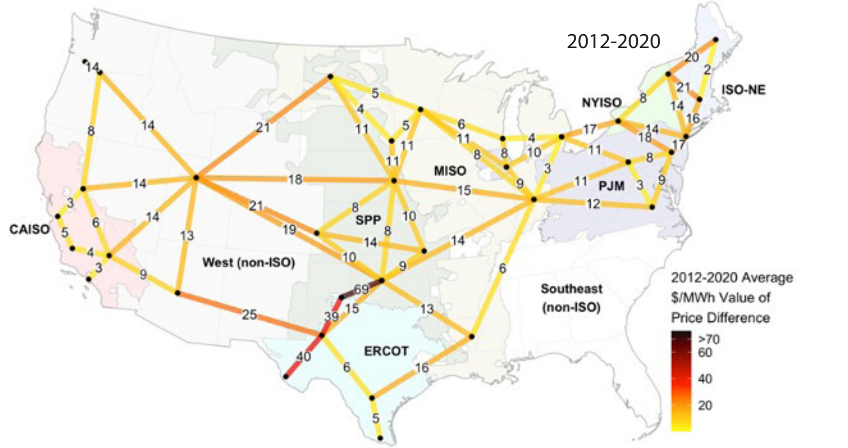
FINDINGS AT A GLANCE

Circuit-miles of new or rebuilt transmission lines (≥100kV) energized between 2011–2020 by project driver.



Transmission projects energized over the last decade in the Midwest region **addressed a diverse set of needs**, including **reliability concerns**.

Congestion value of hypothetical transmission links between select zonal nodes within and across regions.

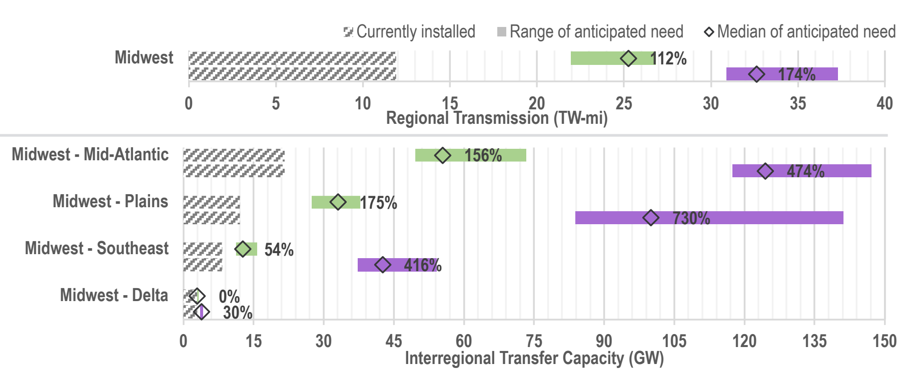


Note: Wholesale market price data is limited for non-RTO/ISO regions. Absence of data does not necessarily indicate that there is no need for transmission to alleviate congestion and/or unscheduled flows in non-RTO/ISO regions. Findings organized using geographic region nomenclature as described in the Needs Study.
Source: D. Millstein, et al. (2022)

Wholesale market price differentials demonstrate the **highest value of new interregional transmission** exists **between the Midwest region and New York**.

The average marginal value of transmission between the Midwest region and New York from 2012–2020 is equal to $17/MWh.

Within-region transmission and interregional transfer capacity need for Midwest in 2035
Range of new transmission need for future scenarios with moderate load and high clean energy growth (green, top for each region) and high load and high clean energy growth (purple, bottom). Median % growth compared to 2020 system shown.



Capacity expansion modeling results for the Moderate/High scenario group suggest an anticipated need of **13.3 TW-miles of new within-region transmission by 2035** (112% growth relative to 2020), and **33.8 GW of new interregional transfer capacity with the Mid-Atlantic region by 2035** (156% growth relative to 2020).

Median 2035 capacity expansion modeling results for Moderate/High scenario group.

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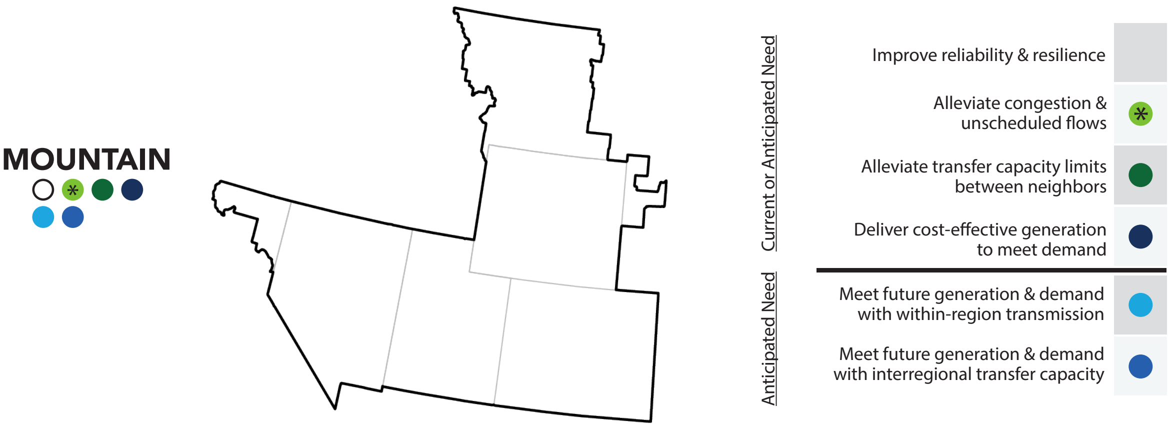
2023 NATIONAL TRANSMISSION NEEDS STUDY

MOUNTAIN REGION

The U.S. Department of Energy's Grid Deployment Office (GDO) released the National Transmission Needs Study ("Needs Study") in October 2023. The Needs Study is the Department's **triennial state of the grid** report. The Needs Study identifies transmission needs and provides information about current and anticipated future capacity constraints and congestion on the Nation's electric transmission grid. In this fact sheet, we highlight the transmission needs of the Mountain region. The Needs Study provides further detail on the benefits of transmission that could be realized throughout the country.



**Wholesale market price data is limited for non-RTO/ISO regions. Absence of data does not necessarily indicate that there is no need for transmission to alleviate congestion and/or unscheduled flows in non-RTO/ISO region.*

FINDINGS OF TRANSMISSION NEED IN THE MOUNTAIN REGION

- **Alleviate congestion and unscheduled flows.** Unscheduled flows in the Mountain region persist, specifically along Colorado's west, south, and north borders, and high congestion values exist within the Mountain region. Additional transmission deployment would help alleviate these needs.

- **Alleviate transfer capacity limits between the Mountain region and its neighbor.** High congestion value of interregional transmission from 2012–2020 exists between the Mountain and Plains region, ranging from \$8/MWh to \$21/MWh. Similarly high congestion values of transmission exist between the Mountain and California (\$14/MWh) and Northwest (\$14/MWh) regions. A high congestion value indicates that increased transmission between the regions would reduce system congestion and constraints.

- **Deliver cost-effective generation to meet demand.** Generation interconnection queues within the Mountain region contain a high number of clean generation projects and county- and state-level renewable energy goals are anticipated to drive future renewable resource development. Transmission buildout would help to accommodate cost-effective resource integration.

- **Meet future generation and demand with additional within-region transmission.** It is anticipated that the Mountain region will need between 2.5 and 4.5 TW-miles of within-region transmission in 2035 (median 3.1 TW-miles, a 90% increase relative to the 2020 system) to meet moderate load growth and high clean energy growth future scenarios.

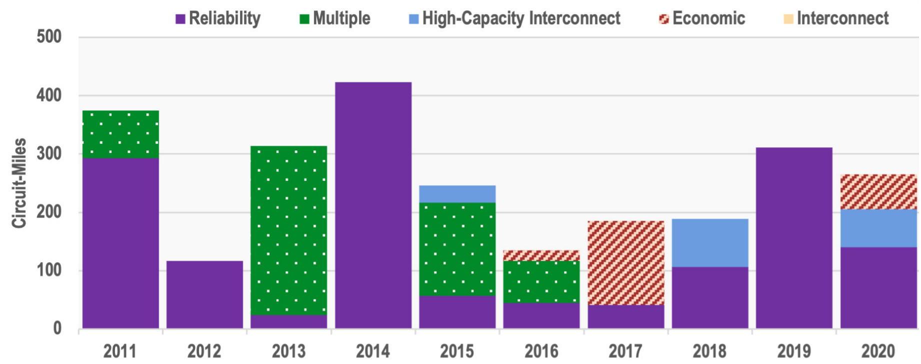
- **Meet future generation and demand with additional interregional transfer capacity.** It is anticipated that the Mountain region will need between 2.7 and 4.4 GW of additional transfer capacity with the Northwest region in 2035 (median of 3.3 GW, a 26% increase relative to the 2020 system) to meet moderate load growth and high clean energy growth future scenarios. Smaller additional transfers between the Mountain and the Southwest (median value of 1.7 GW), California (median value of 1.9 GW), and the Plains (median value of 2.6 GW) regions may also be required.

HELPFUL LINKS

- **Read the full study at www.energy.gov/gdo/national-transmission-needs-study**
- **Contact GDO with additional questions: transmission@hq.doe.gov**

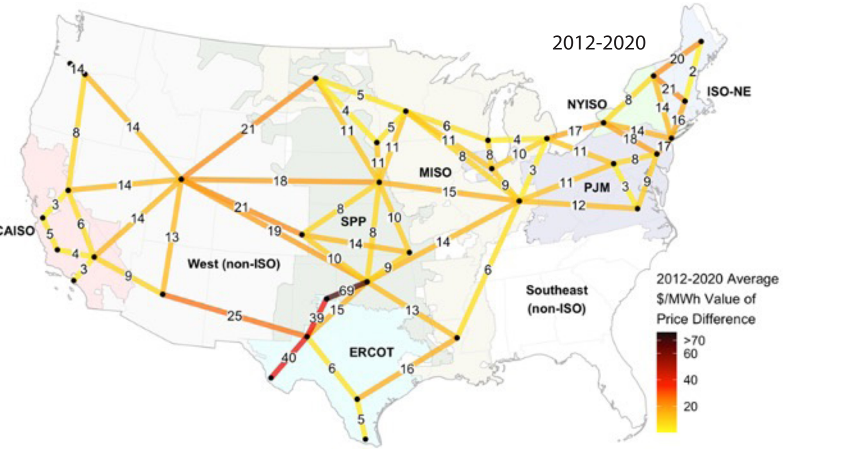
FINDINGS AT A GLANCE

Circuit-miles of new or rebuilt transmission lines (≥100kV) energized between 2011–2020 by project driver.



Transmission projects energized over the last decade in the Mountain region **addressed a diversity of needs**, including **reliability** concerns and to specifically realize **production cost savings**.

Congestion value of hypothetical transmission links between select zonal nodes within and across regions.

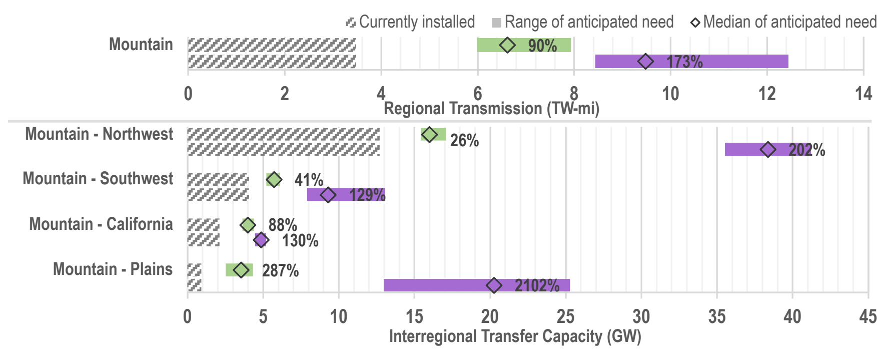


Note: Wholesale market price data is limited for non-RTO/ISO regions. Absence of data does not necessarily indicate that there is no need for transmission to alleviate congestion and/or unscheduled flows in non-RTO/ISO regions. Findings organized using geographic region nomenclature as described in the Needs Study.
Source: D. Millstein, et al. (2022)

Wholesale market price differentials demonstrate the **highest value of new interregional transmission** exists **between the Mountain and Plains region**.

The average marginal value of transmission between the Mountain and Plains regions from 2012–2020 is equal to $15/MWh.

Within-region transmission and interregional transfer capacity need for Mountain in 2035
Range of new transmission need for future scenarios with moderate load and high clean energy growth (green, top for each region) and high load and high clean energy growth (purple, bottom). Median % growth compared to 2020 system shown.



Capacity expansion modeling results for the Moderate/High scenario group suggest an anticipated need of **3.1 TW miles of new within-region transmission by 2035** (90% growth relative to 2020) and **3.3 GW of new interregional transfer capacity with the Northwest region by 2035** (26% growth relative to 2020).

Median 2035 capacity expansion modeling results for Moderate/High scenario group.

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2023 NATIONAL TRANSMISSION NEEDS STUDY

NEW ENGLAND

The U.S. Department of Energy's Grid Deployment Office (GDO) released the National Transmission Needs Study ("Needs Study") in October 2023. The Needs Study is the Department's **triennial state of the grid** report. The Needs Study identifies transmission needs and provides information about current and anticipated future capacity constraints and congestion on the Nation's electric transmission grid. In this fact sheet, we highlight the transmission needs of New England. The Needs Study provides further detail on the benefits of transmission that could be realized throughout the country.

NEW ENGLAND

Current or Anticipated Need	Improve reliability & resilience	●
	Alleviate congestion & unscheduled flows	
	Alleviate transfer capacity limits between neighbors	●
	Deliver cost-effective generation to meet demand	●
Anticipated Need	Meet future generation & demand with within-region transmission	
	Meet future generation & demand with interregional transfer capacity	●

FINDINGS OF TRANSMISSION NEED IN NEW ENGLAND

› **Improve reliability and resilience.** Resource adequacy will be harder to maintain in a future where load is served by only variable energy resources. A robust transmission system is needed to access a diverse generation mix throughout the region. Increased interregional transmission provides resilience and consumer saving benefits during extreme weather events, as experienced by the Northeast in the January 2018 bomb cyclone event.

› **Alleviate transfer capacity limits between New England and New York.** The highest congestion value of interregional transmission in the Eastern Interconnection from 2012–2020 exists between New England and New York, with an average marginal value of transmission ranging from $16–21/MWh. A high congestion value indicates that additional transmission between the regions would reduce system congestion and constraints.

› **Deliver cost-effective generation to meet demand.** Increased interregional transmission provides resilience and consumer saving benefits, as experienced by the Northeast in the January 2018 bomb cyclone event.

› **Meet future generation and demand with additional interregional transfer capacity.** It is anticipated that New England will need between 3.4 and 6.3 GW of additional transfer capacity with New York in 2035 (median of 5.2 GW, a 255% increase relative to the 2020 system) to meet moderate load growth and high clean energy growth future scenarios.

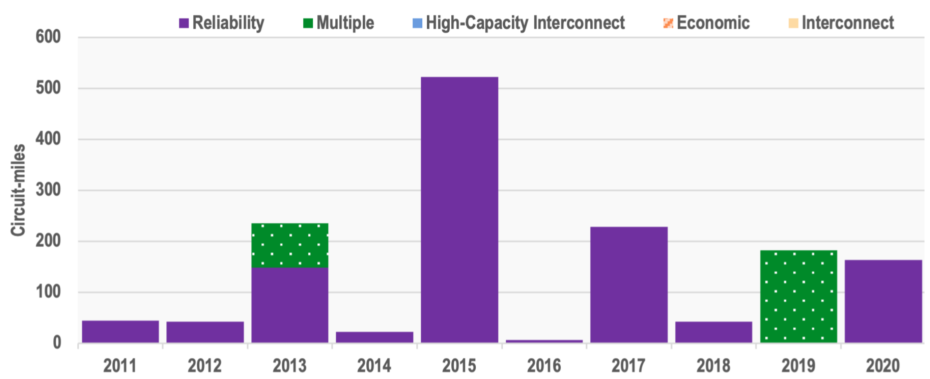
HELPFUL LINKS

› **Read the full study at www.energy.gov/gdo/national-transmission-needs-study**

› **Contact GDO with additional questions: transmission@hq.doe.gov**

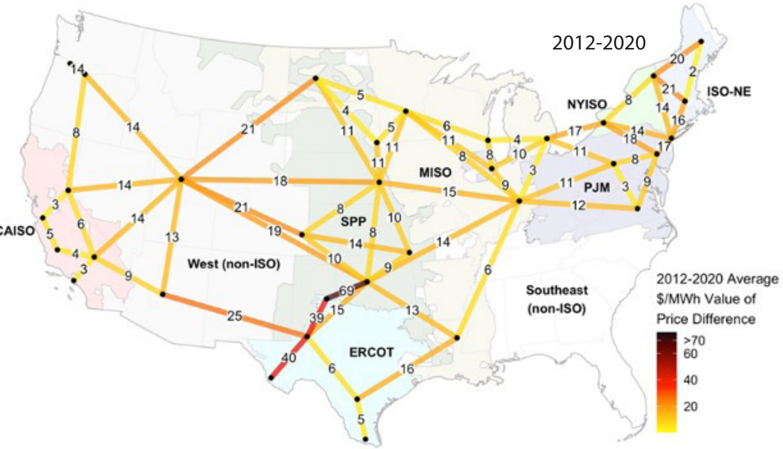
FINDINGS AT A GLANCE

Circuit-miles of new or rebuilt transmission lines (≥100kV) energized between 2011–2020 by project driver.



Transmission projects energized over the last decade in New England were predominantly installed to **address reliability concerns**, and occasionally to address multiple drivers.

Congestion value of hypothetical transmission links between select zonal nodes within and across regions.

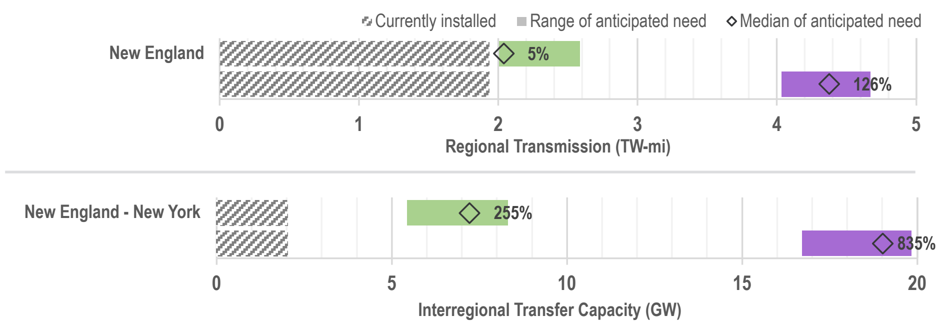


Note: Wholesale market price data is limited for non-RTO/ISO regions. Absence of data does not necessarily indicate that there is no need for transmission to alleviate congestion and/or unscheduled flows in non-RTO/ISO regions. Findings organized using geographic region nomenclature as described in the Needs Study.
Source: D. Millstein, et al. (2022)

Wholesale market price differentials demonstrate a **high value of new interregional transmission** exists **between New England and New York**.

The average marginal value of transmission between New England and New York from 2012–2020 is equal to $19/MWh.

Within-region transmission and interregional transfer capacity need for New England in 2035
Range of new transmission need for future scenarios with moderate load and high clean energy growth (green, top for each region) and high load and high clean energy growth (purple, bottom). Median % growth compared to 2020 system shown.



Capacity expansion modeling results for the Moderate/High scenario group suggest an anticipated need of **0.1 TW-mi of new within-region transmission by 2035** (5% growth relative to 2020) and **5.2 GW of new interregional transfer capacity with New York by 2035** (255% growth relative to 2020).

Median 2035 capacity expansion modeling results for Moderate/High scenario group.

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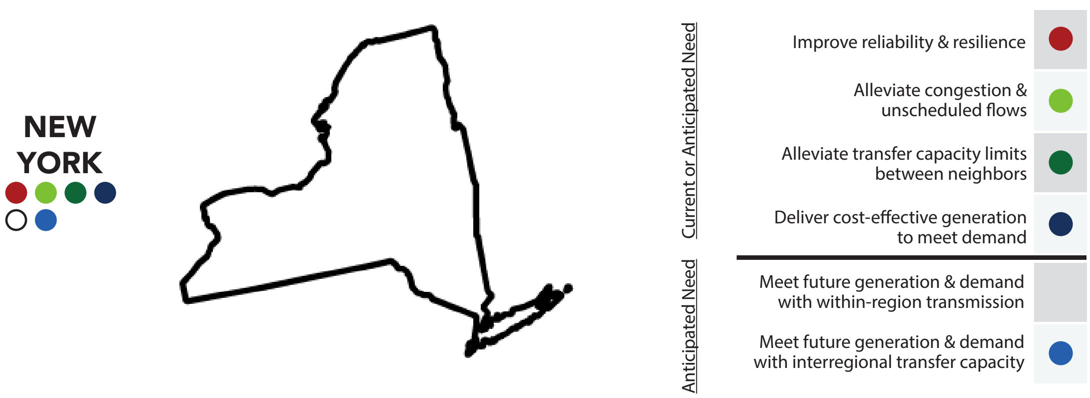
2023 NATIONAL TRANSMISSION NEEDS STUDY

NEW YORK

The U.S. Department of Energy's Grid Deployment Office (GDO) released the National Transmission Needs Study ("Needs Study") in October 2023. The Needs Study is the Department's **triennial state of the grid** report. The Needs Study identifies transmission needs and provides information about current and anticipated future capacity constraints and congestion on the Nation's electric transmission grid. In this fact sheet, we highlight the transmission needs of New York. The Needs Study provides further detail on the benefits of transmission that could be realized throughout the country.



FINDINGS OF TRANSMISSION NEED IN NEW YORK

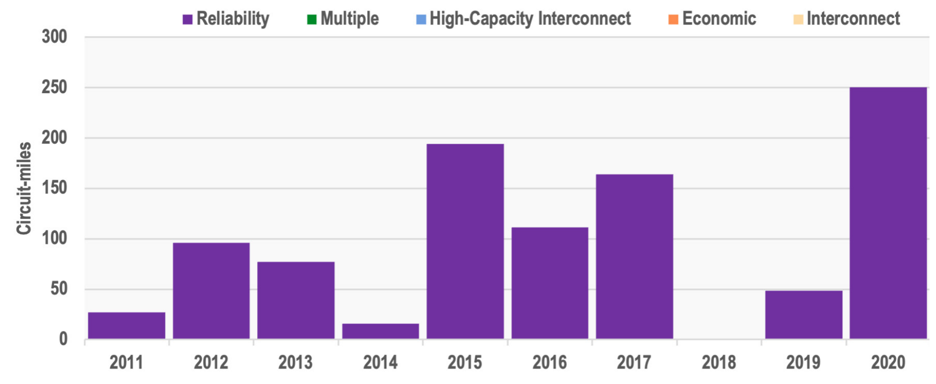
- **Improve reliability and resilience.** Reliability risks are anticipated to increase during winter months by mid-2030 as the grid is becoming winter-peaking. Expanding transmission to access geographically diverse energy resources would reduce resource future adequacy risks. Increased interregional transmission provides resilience and consumer saving benefits during extreme weather events, as experienced by New York in the January 2018 bomb cyclone event.
- **Alleviate congestion and unscheduled flows.** High congestion values exist within New York, indicating that additional transmission deployment would reduce system congestion and constraints. Long-term planning scenarios with a significant portion of renewable generation would exacerbate existing transmission congestion with a 23% increase statewide by 2030.
- **Alleviate transfer capacity limits between New York and its neighbors.** The highest congestion value of interregional transmission in the Eastern Interconnection from 2012–2020 exists between New York and New England, with an average marginal value of transmission ranging from $16–21/MWh. Similarly high congestion values exist between New York and the Mid-Atlantic ($18/MWh) and Midwest ($17/MWh) regions. A high congestion value indicates that transmission between the regions would reduce system congestion and constraints.
- **Deliver cost-effective generation to meet demand.** High-priced areas in Long Island persist and additional transmission to bring cost-effective resources to demand would help reduce these prices.
- **Meet future generation and demand with additional interregional transfer capacity.** It is anticipated that New York will need between 3.4 and 6.3 GW of additional transfer capacity with New England in 2035 (median of 5.2 GW, a 255% increase relative to the 2020 system) to meet moderate load growth and high clean energy growth future scenarios. Smaller additional transfer capacity between New York and the Mid-Atlantic region (median value of 2.4 GW) may also be required.

HELPFUL LINKS

- **Read the full study at www.energy.gov/gdo/national-transmission-needs-study**
- **Contact GDO with additional questions: transmission@hq.doe.gov**

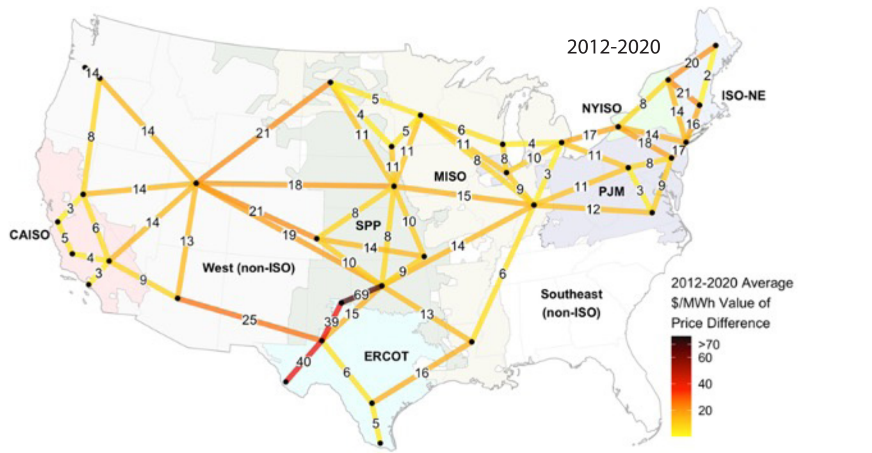
FINDINGS AT A GLANCE

Circuit-miles of new or rebuilt transmission lines (≥100kV) energized between 2011–2020 by project driver.



Transmission projects energized over the last decade in New York were installed exclusively to **address reliability concerns**.

Congestion value of hypothetical transmission links between select zonal nodes within and across regions.

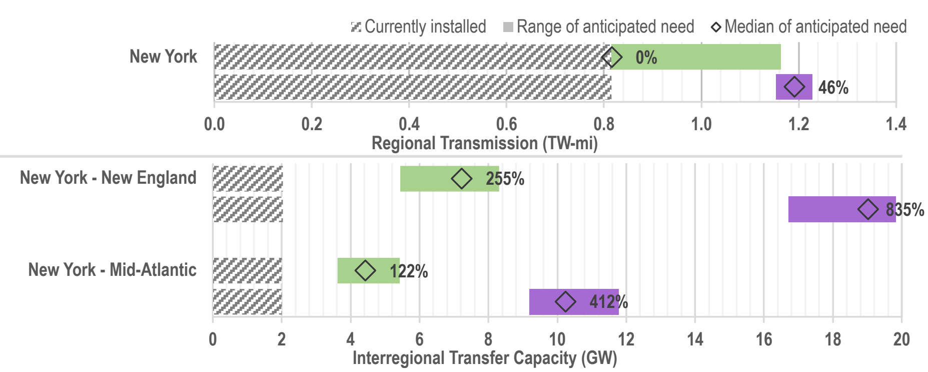


Note: Wholesale market price data is limited for non-RTO/ISO regions. Absence of data does not necessarily indicate that there is no need for transmission to alleviate congestion and/or unscheduled flows in non-RTO/ISO regions. Findings organized using geographic region nomenclature as described in the Needs Study.
Source: D. Millstein, et al. (2022)

Wholesale market price differentials demonstrate a **high value of new interregional transmission** exists **between New York and New England**.

The average marginal value of transmission between New York and New England from 2012–2020 is equal to $19/MWh.

Within-region transmission and interregional transfer capacity need for New York in 2035
Range of new transmission need for future scenarios with moderate load and high clean energy growth (green, top for each region) and high load and high clean energy growth (purple, bottom). Median % growth compared to 2020 system shown.



Capacity expansion modeling results for the Moderate/High scenario group suggest an anticipated need of **5.2 GW of new interregional transfer capacity with New England by 2035** (255% growth relative to 2020) and **2.4 GW with the Mid-Atlantic region by 2035** (122% growth relative to 2020).

Median 2035 capacity expansion modeling results for Moderate/High scenario group.

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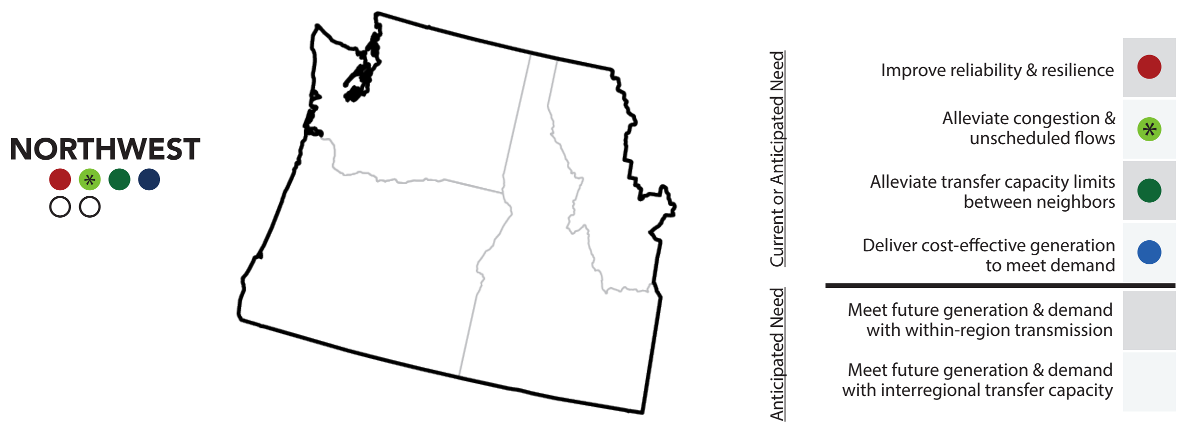
2023 NATIONAL TRANSMISSION NEEDS STUDY

NORTHWEST REGION

The U.S. Department of Energy's Grid Deployment Office (GDO) released the National Transmission Needs Study ("Needs Study") in October 2023. The Needs Study is the Department's **triennial state of the grid** report. The Needs Study identifies transmission needs and provides information about current and anticipated future capacity constraints and congestion on the Nation's electric transmission grid. In this fact sheet, we highlight the transmission needs of the Northwest region. The Needs Study provides further detail on the benefits of transmission that could be realized throughout the country.



**Wholesale market price data is limited for non-RTO/ISO regions. Absence of data does not necessarily indicate that there is no need for transmission to alleviate congestion and/or unscheduled flows in non-RTO/ISO regions.*

FINDINGS OF TRANSMISSION NEED IN THE NORTHWEST REGION

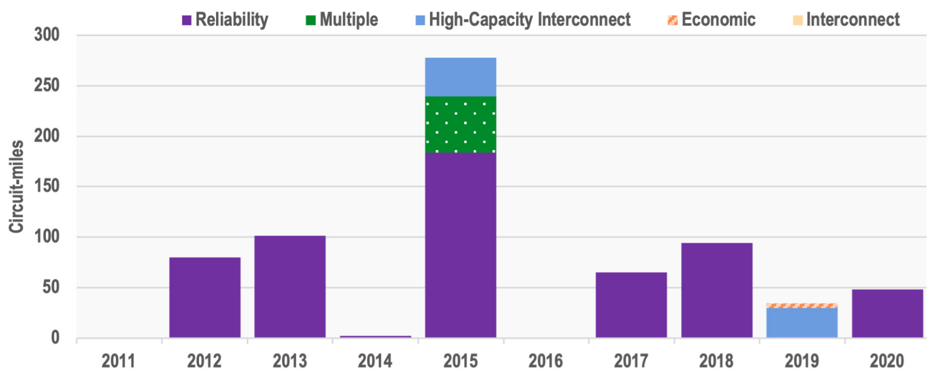
- **Improve reliability and resilience.** The Northwest faces risk of load curtailment during extreme weather events and wildfires, particularly as the region becomes increasingly reliant on variable energy resources to meet peak demand. Additional transmission upgrades would reduce risks to electricity reliability from extreme events.
- **Alleviate congestion and unscheduled flows.** Unscheduled flows persist on Qualified Path 66 located at the intersection of the Northwest, California, and Mountain regions and high congestion values exist within the Northwest region. Additional transmission deployment would help alleviate these needs.
- **Alleviate transfer capacity limits between the Northwest and Mountain regions.** High congestion value of interregional transmission from 2012–2020 exists between the Northwest and the Mountain region, with an average marginal value of transmission equal to $14/MWh. A high congestion value indicates that increased transmission between the regions would reduce system congestion and constraints.
- **Deliver cost-effective generation to meet demand.** The Northwest is anticipated to integrate higher levels of new generation to meet state-level power sector emissions reduction targets. Additional interregional transmission would allow for an increase of cost-effective, out-of-state clean energy imports, as well as the export of low-cost clean energy from the Northwest region to other western states.

HELPFUL LINKS

- **Read the full study at www.energy.gov/gdo/national-transmission-needs-study**
- **Contact GDO with additional questions: transmission@hq.doe.gov**

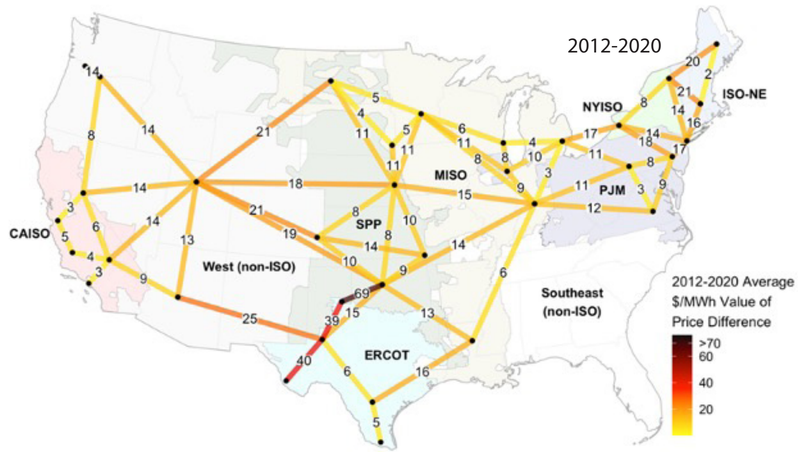
FINDINGS AT A GLANCE

Circuit-miles of new or rebuilt transmission lines (≥100kV) energized between 2011–2020 by project driver.



Transmission projects energized over the last decade in the Northwest were predominantly installed to **address reliability concerns**.

Congestion value of hypothetical transmission links between select zonal nodes within and across regions.

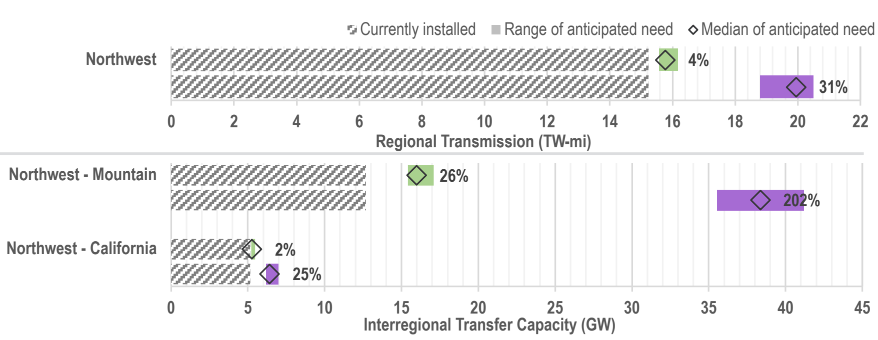


Note: Wholesale market price data is limited for non-RTO/ISO regions. Absence of data does not necessarily indicate that there is no need for transmission to alleviate congestion and/or unscheduled flows in non-RTO/ISO regions. Findings organized using geographic region nomenclature as described in the Needs Study.
Source: D. Millstein, et al. (2022)

Wholesale market price differentials demonstrate a **high value of new interregional transmission** exists **between the Northwest and Mountain** regions.

The average marginal value of transmission between the Northwest and the Mountain region from 2012–2020 is equal to $14/MWh.

Within-region transmission and interregional transfer capacity need for Northwest in 2035
Range of new transmission need for future scenarios with moderate load and high clean energy growth (green, top for each region) and high load and high clean energy growth (purple, bottom). Median % growth compared to 2020 system shown.



Capacity expansion modeling results for the Moderate/High scenario group suggest an anticipated need of **0.5 TW-miles of new within-region transmission by 2035** (4% growth relative to 2020) and **3.3 GW of new interregional transfer capacity with the Mountain region by 2035** (26% growth relative to 2020).

Median 2035 capacity expansion modeling results for Moderate/High scenario group.

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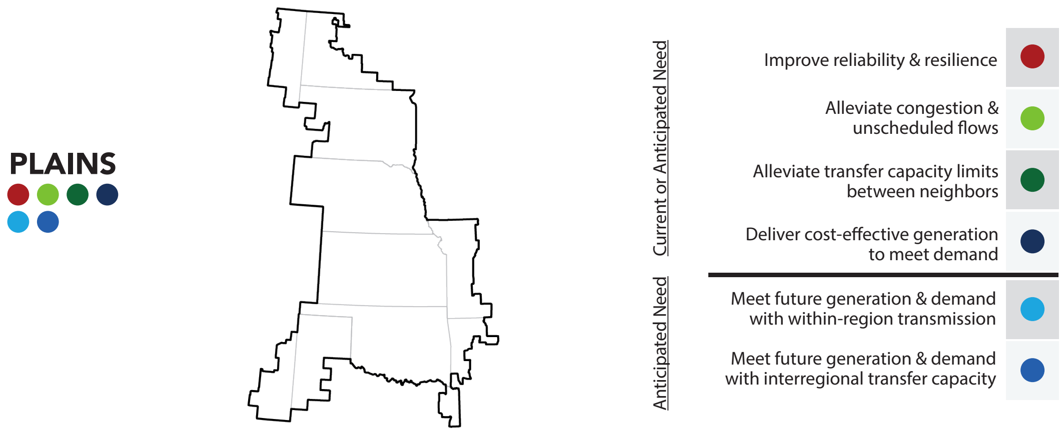
2023 NATIONAL TRANSMISSION NEEDS STUDY

PLAINS REGION

The U.S. Department of Energy's Grid Deployment Office (GDO) released the National Transmission Needs Study ("Needs Study") in October 2023. The Needs Study is the Department's **triennial state of the grid** report. The Needs Study identifies transmission needs and provides information about current and anticipated future capacity constraints and congestion on the Nation's electric transmission grid. In this fact sheet, we highlight the transmission needs of the Plains region. The Needs Study provides further detail on the benefits of transmission that could be realized throughout the country.



FINDINGS OF TRANSMISSION NEED IN THE PLAINS REGION

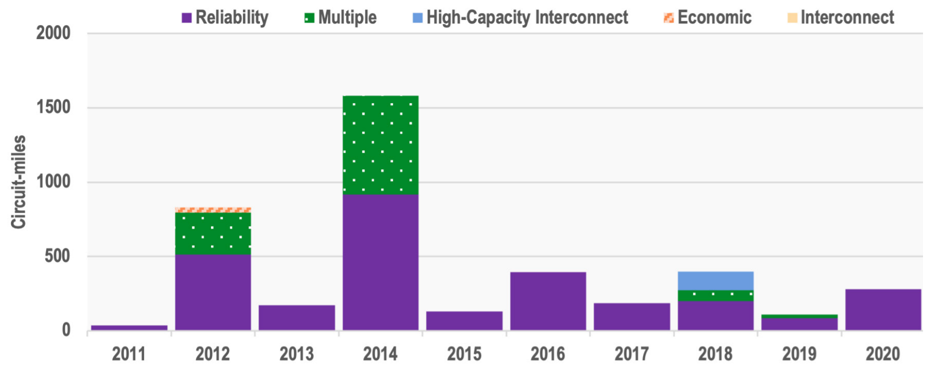
- **Improve reliability and resilience.** The Plains region was unable to import additional generation capacity during the February 2021 cold weather event, negatively impacting resource adequacy. Increased bi-directional transfer capacities with neighboring regions would improve system reliability during extreme weather events.
- **Alleviate congestion and unscheduled flows.** In 2020, high wind generation output and transmission limitations generated high congestion costs in eastern Kansas, southwestern Missouri, and southeastern Oklahoma. Increased transmission capacity within the region would help increase transmission capability for wind-producing areas and reduce prices in congested areas.
- **Alleviate transfer capacity limits between the Plains region and its neighbors.** Highest congestion value of interregional transmission from 2012–2020 exists between the Plains region and Texas, ranging from $15/MWh to $69/MWh. High congestion values of transmission also exist between the Plains and Mountain ($8/MWh–$21/MWh) and Midwest ($4/MWh–$15/MWh) regions. A high congestion value indicates that increased transmission between the regions would reduce system congestion and constraints.
- **Deliver cost-effective generation to meet demand.** High-priced areas persist in southern Oklahoma and southwest Missouri and additional transmission to bring cost-effective generation to demand would help these reduce prices.
- **Meet future generation and demand with additional within-region transmission.** It is anticipated that the Plains region will need between 7.3 and 9.9 TW-miles of within-region transmission in 2035 (median 8.3 TW-miles, a 119% increase relative to the 2020 system) to meet moderate load growth and high clean energy growth future scenarios.
- **Meet future generation and demand with additional interregional transfer capacity.** It is anticipated that the Plains will need between 15.4 and 25.8 GW of additional transfer capacity with the Midwest in 2035 (median of 21.1 GW, a 175% increase relative to the 2020 system) to meet moderate load growth and high clean energy growth future scenarios. Smaller transfers between the Plains region and the Delta (median value of 19.7 GW), Texas (median value of 9.8 GW), Southwest (median value of 3.7 GW), and Mountain (median value of 2.6 GW) regions may also be required.

HELPFUL LINKS

- **Read the full study at www.energy.gov/gdo/national-transmission-needs-study**
- **Contact GDO with additional questions: transmission@hq.doe.gov**

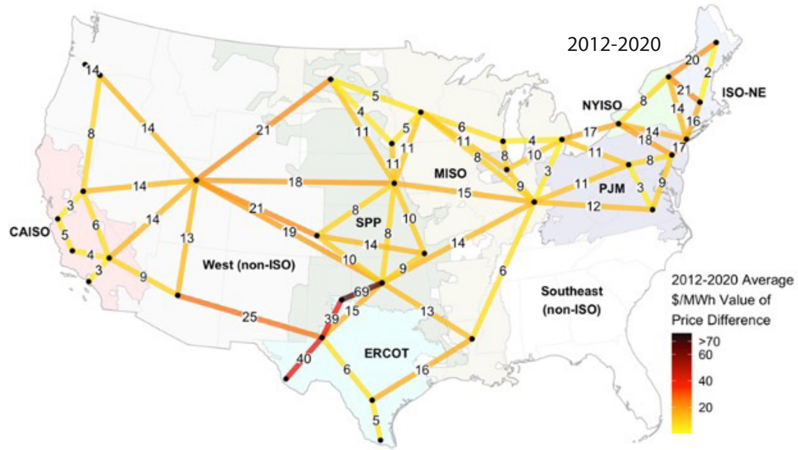
FINDINGS AT A GLANCE

Circuit-miles of new or rebuilt transmission lines (≥100kV) energized between 2011–2020 by project driver.



Transmission projects energized over the last decade in the Plains region were predominantly installed to **address reliability concerns**.

Congestion value of hypothetical transmission links between select zonal nodes within and across regions.

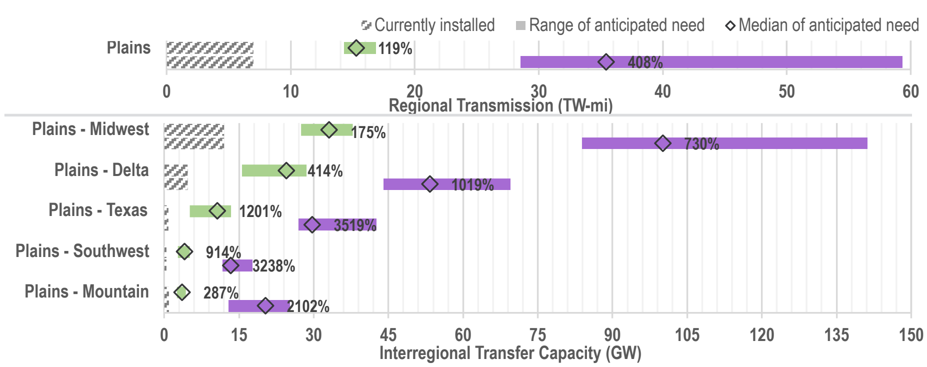


Note: Wholesale market price data is limited for non-RTO/ISO regions. Absence of data does not necessarily indicate that there is no need for transmission to alleviate congestion and/or unscheduled flows in non-RTO/ISO regions. Findings organized using geographic region nomenclature as described in the Needs Study.
Source: D. Millstein, et al. (2022)

Wholesale market price differentials demonstrate a **high value of new interregional transmission** exists **between the Plains region and Texas**.

The average marginal value of transmission between the Plains region and Texas from 2012–2020 is equal to $42/MWh.

Within-region transmission and interregional transfer capacity need for Plains in 2035
Range of new transmission need for future scenarios with moderate load and high clean energy growth (green, top for each region) and high load and high clean energy growth (purple, bottom). Median % growth compared to 2020 system shown.



Capacity expansion modeling results for the Moderate/High scenario group suggest an anticipated need of **8.3 TW-miles of new within-region transmission by 2035** (119% growth relative to 2020) and **21.1 GW of new interregional transfer capacity with the Midwest region by 2035** (175% growth relative to 2020).

Median 2035 capacity expansion modeling results for Moderate/High scenario group.

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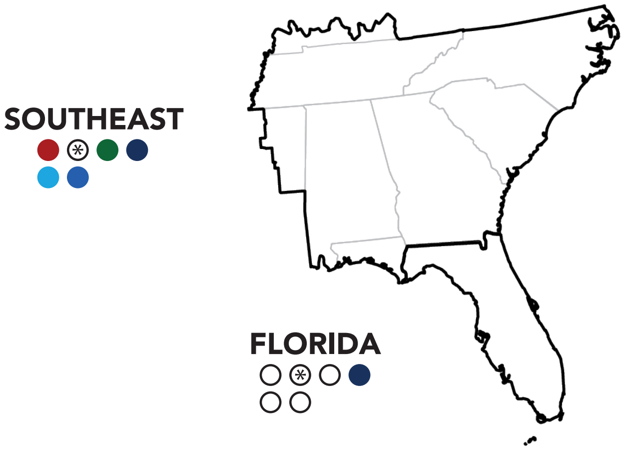
FACT SHEET

2023 NATIONAL TRANSMISSION NEEDS STUDY

SOUTHEAST AND FLORIDA

The U.S. Department of Energy's Grid Deployment Office (GDO) released the National Transmission Needs Study ("Needs Study") in October 2023. The Needs Study is the Department's **triennial state of the grid** report. The Needs Study identifies transmission needs and provides information about current and anticipated future capacity constraints and congestion on the Nation's electric transmission grid. In this fact sheet, we highlight the transmission needs of the Southeast and Florida. The Needs Study provides further detail on the benefits of transmission that could be realized throughout the country.



		Southeast	Florida
Current or Anticipated Need	Improve reliability & resilience	●	
	Alleviate congestion & unscheduled flows	*	*
	Alleviate transfer capacity limits between neighbors	●	
	Deliver cost-effective generation to meet demand	●	●
Anticipated Need	Meet future generation & demand with within-region transmission	●	
	Meet future generation & demand with interregional transfer capacity	●	

**Wholesale market price data is limited for non-RTO/ISO regions. Absence of data does not necessarily indicate that there is no need for transmission to alleviate congestion and/or unscheduled flows in non-RTO/ISO regions.*

FINDINGS OF TRANSMISSION NEED IN THE SOUTHEAST AND FLORIDA

Fewer transmission system data and references were available for the Southeast and Florida than for many other regions of the country. These findings are incomplete for these regions given this lack of historic information.

› **Improve reliability and resilience.** Extreme events in the Southeast can lead to generation shortages and blackouts, even when neighboring regions have excess generation. Increased transfer capacity between the Southeast and its neighbors would have helped Southeastern utilities service customer load during Winter Storm Elliott in 2022. Additional transmission infrastructure within the Southeast region would provide reliable electric service to some areas as generation retirements occur. Hurricanes pose a threat to both the Southeast and Florida, and the hardening of the existing system would increase resilience to these intensifying events.

› **Alleviate transfer capacity limits between the Southeast and its neighbors.** Increased transfer capacity between the Southeast and its neighbors would result in consumer savings. Transfer capacity limits between the Southeast and its neighbors during Winter Storm Elliot led to forgone savings estimated to total nearly $100 million.

› **Deliver cost-effective generation to meet demand.** Both market forces and public policy are driving rapid changes in generation and demand in the Southeast and Florida. Capacity expansion modeling suggests that transmission upgrades within the Southeast and between the Southeast and Florida will be necessary to deliver cost-effective generation to load under a variety of different transmission technology scenarios.

HELPFUL LINKS

› **Read the full study at www.energy.gov/gdo/national-transmission-needs-study**

› **Contact GDO with additional questions: transmission@hq.doe.gov**

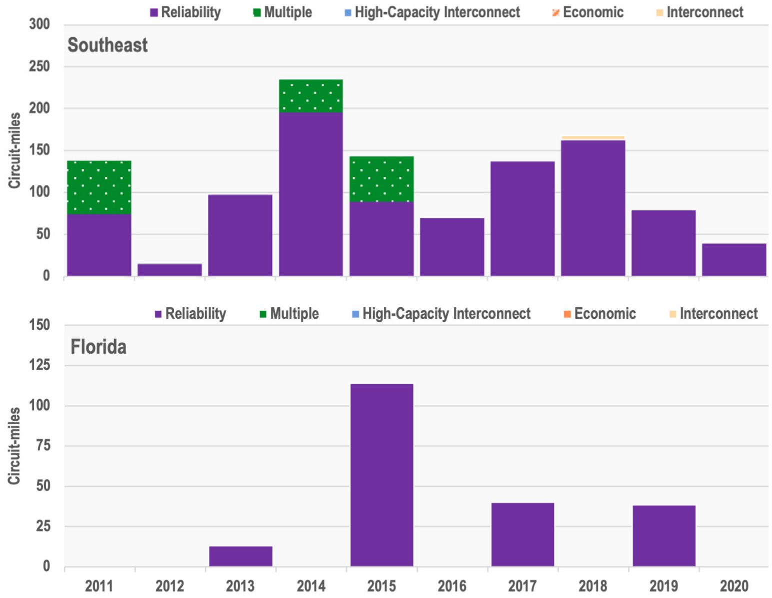
FINDINGS OF TRANSMISSION NEED IN THE SOUTHEAST AND FLORIDA (CONT.)

- **Meet future generation and demand with additional within-region transmission.** It is anticipated that the Southeast region will need between 5.4 and 8 TW-miles of within-region transmission in 2035 (median 6.8 TW-miles, a 77% increase relative to the 2020 system) to meet moderate load growth and high clean energy growth future scenarios. Median growth of anticipated within-region transmission need in Florida was less than 25% relative to the 2020 system in 2035 under the same future scenarios.

- **Meet future generation and demand with additional interregional transfer capacity.** It is anticipated that the Southeast region will need between 5.8 and 9.9 GW of additional transfer capacity with the Mid-Atlantic region in 2035 (median of 6.9 GW, a 97% increase relative to the 2020 system) to meet moderate load growth and high clean energy growth future scenarios. Smaller transfers between the Southeast region and the Delta (median value of 5.1 GW) and Midwest (median value of 4.5 GW) regions will also be required. Median growth of anticipated transfer capacity need between the Southeast and Florida was 32% relative to the 2020 system in 2035 under the same future scenarios.

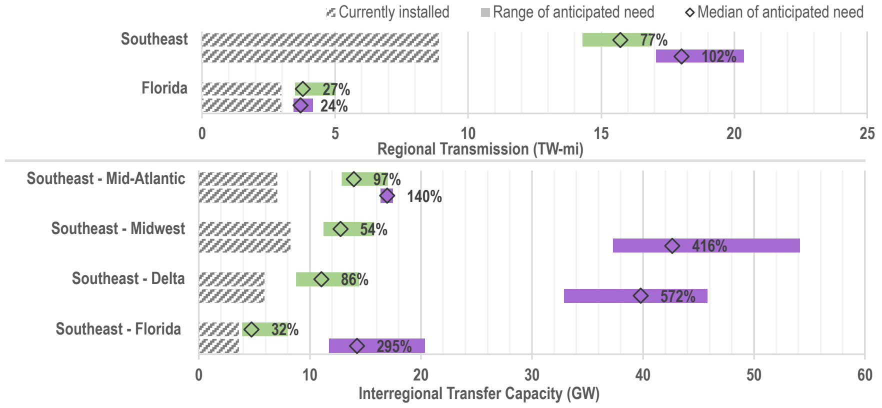
FINDINGS AT A GLANCE

Circuit-miles of new or rebuilt transmission lines (≥100kV) energized between 2011–2020 by project driver.



Projects energized from 2011-2020 in Southeast and Florida were almost exclusively installed to **address reliability concerns**. Less than half of projects installed in the Southeast prior to 2016 were to address **multiple drivers**.

Within-region transmission and interregional transfer capacity need for Southeast & Florida in 2035
Range of new transmission need for future scenarios with moderate load and high clean energy growth (green, top for each region) and high load and high clean energy growth (purple, bottom). Median % growth compared to 2020 system shown.



Capacity expansion modeling results for the Moderate/High scenario group suggest an anticipated need of **6.8 TW-miles of new within-region transmission in the Southeast** (77% growth relative to 2020) and **0.8 TW-miles in Florida by 2035** (27% growth relative to 2020). **Significant new interregional transfer capacity growth is needed between the Southeast and its neighbors by 2035**.

Median 2035 capacity expansion modeling results for Moderate/High scenario group.

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FACT SHEET

2023 NATIONAL TRANSMISSION NEEDS STUDY

SOUTHWEST REGION

The U.S. Department of Energy's Grid Deployment Office (GDO) released the National Transmission Needs Study ("Needs Study") in October 2023. The Needs Study is the Department's **triennial state of the grid** report. The Needs Study identifies transmission needs and provides information about current and anticipated future capacity constraints and congestion on the Nation's electric transmission grid. In this fact sheet, we highlight the transmission needs of the Southwest. The Needs Study provides further detail on the benefits of transmission that could be realized throughout the country.

**Wholesale market price data is limited for non-RTO/ISO regions. Absence of data does not necessarily indicate that there is no need for transmission to alleviate congestion and/or unscheduled flows in non-RTO/ISO regions.*

FINDINGS OF TRANSMISSION NEED IN THE SOUTHWEST REGION

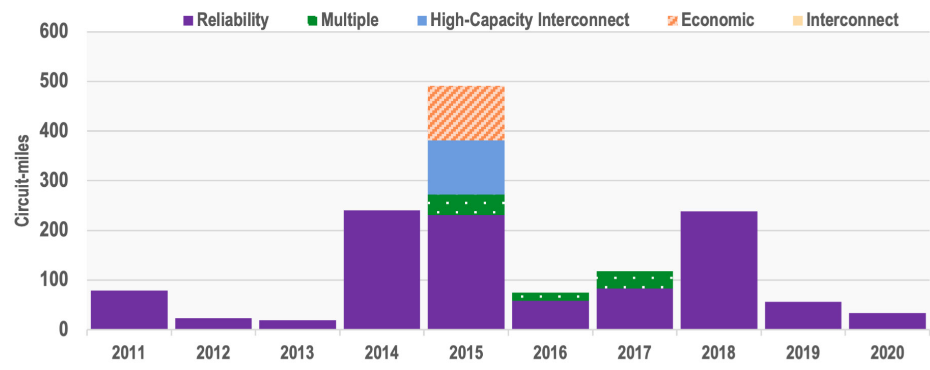
- **Improve reliability and resilience.** The Southwest region is approaching system conditions which present the risk of load curtailment during extreme weather events and wildfires, especially as the region's reliance on variable energy resources to meet peak demand increases. Additional transmission upgrades in the near term would reduce risks to electricity reliability from extreme events.
- **Alleviate congestion and unscheduled flows.** Unscheduled flows persist on Qualified Path 31 located near the southern Colorado and northern New Mexico border; additional transmission deployment would alleviate these unscheduled flows.
- **Alleviate transfer capacity limits between the Southwest region and Texas.** High congestion value of interregional transmission from 2012–2020 exists between the Southwest region and Texas, with an average marginal value of transmission equal to $25/MWh. A high congestion value indicates that increased transmission between the regions would reduce system congestion and constraints.
- **Meet future generation and demand with additional interregional transfer capacity.** It is anticipated that the Southwest will need between 2.3 and 4.7 GW of additional transfer capacity with the Plains region in 2035 (median of 3.7 GW, a 914% increase relative to the 2020 system) to meet moderate load growth and high clean energy growth future scenarios. Smaller additional transfers between the Southwest and Mountain (median value of 1.7 GW) and California (median value of 0.3 GW) regions may also be required.

HELPFUL LINKS

- **Read the full study at www.energy.gov/gdo/national-transmission-needs-study**
- **Contact GDO with additional questions: transmission@hq.doe.gov**

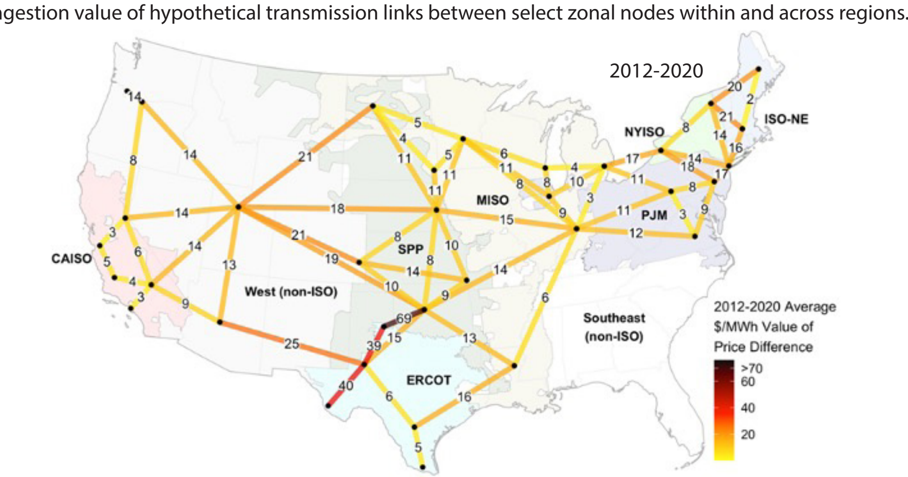
FINDINGS AT A GLANCE

Circuit-miles of new or rebuilt transmission lines (≥100kV) energized between 2011-2020 by project driver.



Transmission projects energized over the last decade in the Southwest region were predominantly, but not exclusively, installed to **address reliability concerns**.

Congestion value of hypothetical transmission links between select zonal nodes within and across regions.

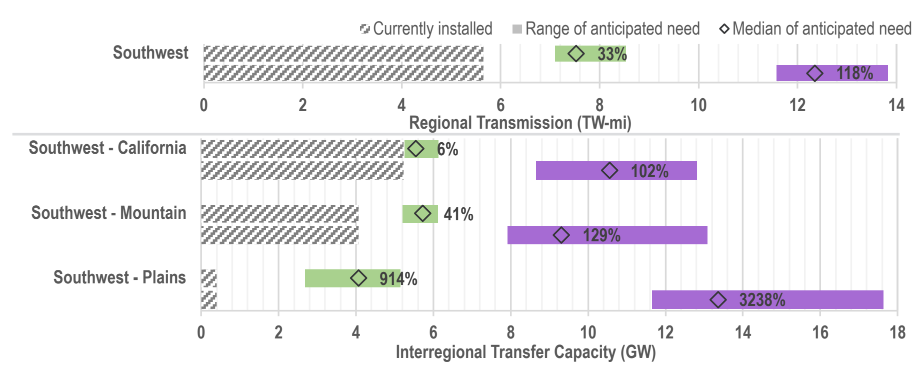


Note: Wholesale market price data is limited for non-RTO/ISO regions. Absence of data does not necessarily indicate that there is no need for transmission to alleviate congestion and/or unscheduled flows in non-RTO/ISO regions. Findings organized using geographic region nomenclature as described in the Needs Study.
Source: D. Millstein, et al. (2022)

Wholesale market price differentials demonstrate a **high value of new interregional transmission** exists **between the Southwest region and Texas**.

The average marginal value of transmission between the Southwest region and Texas from 2012–2020 is equal to $25/MWh.

Within-region transmission and interregional transfer capacity need for Southwest in 2035
Range of new transmission need for future scenarios with moderate load and high clean energy growth (green, top for each region) and high load and high clean energy growth (purple, bottom). Median % growth compared to 2020 system shown.



Capacity expansion modeling results for the Moderate/High scenario group suggest an anticipated need of **1.9 TW-miles of new within-region transmission by 2035** (33% growth relative to 2020) and **3.7 GW of new interregional transmission deployment with the Plains region by 2035** (914% growth relative to 2020).

Median 2035 capacity expansion modeling results for Moderate/High scenario group.

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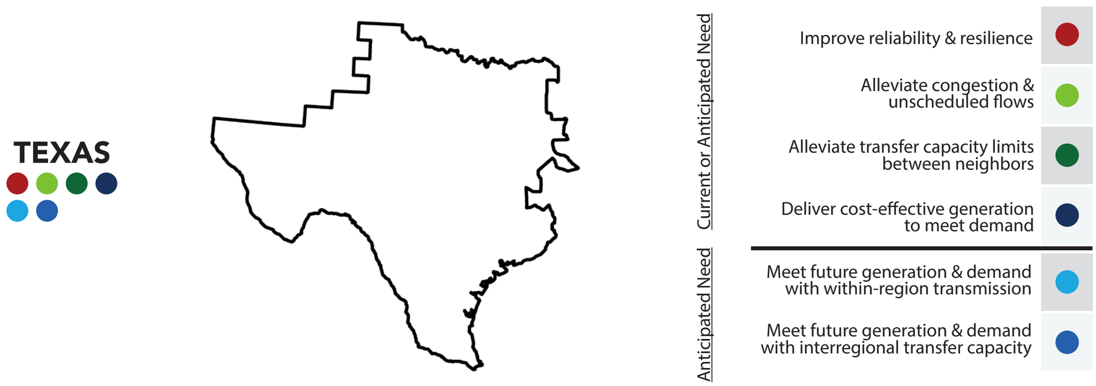
2023 NATIONAL TRANSMISSION NEEDS STUDY

TEXAS

The U.S. Department of Energy's Grid Deployment Office (GDO) released the National Transmission Needs Study ("Needs Study") in October 2023. The Needs Study is the Department's **triennial state of the grid** report. The Needs Study identifies transmission needs and provides information about current and anticipated future capacity constraints and congestion on the Nation's electric transmission grid. In this fact sheet, we highlight the transmission needs of Texas. The Needs Study provides further detail on the benefits of transmission that could be realized throughout the country.



FINDINGS OF TRANSMISSION NEED IN TEXAS

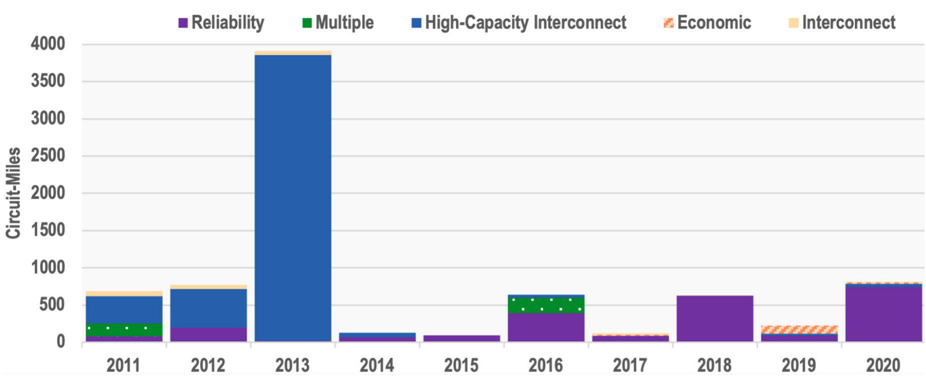
- **Improve reliability and resilience.** Limited transfer capacity with neighboring regions significantly affects the ability for Texas to address capacity shortages when the system is stressed under emergency conditions, such as those experienced during the February 2021 cold weather event. Increased bi-directional transfer capacities with neighboring regions would improve system reliability during extreme weather events.
- **Alleviate congestion and unscheduled flows.** High congestion values exist within Texas, indicating that additional transmission deployment would reduce system congestion and constraints. Texas is also anticipated to experience significant congestion due to increases in generation in the western part of the state and limited within-region transmission export capacity into demand centers such as the Dallas-Fort Worth and Houston areas.
- **Alleviate transfer capacity limits between Texas and the Plains region.** The highest congestion values of interregional transmission from 2012–2020 across the entire United States exists between Texas and the Plains region, ranging from \$15/MWh to \$69/MWh. Similarly high congestion values of transmission exist between Texas and the Southwest (\$25/MWh) and Delta (\$16/MWh) regions.
- **Deliver cost-effective generation to meet demand.** A high proportion of planned, cost-effective renewable resource additions within Texas are located in western Texas, which is a significant distance from load centers located in the eastern part of the state. Capacity expansion modeling suggests that transmission upgrades within Texas will be necessary to deliver cost-effective generation to load under a variety of different transmission technology scenarios.
- **Meet future generation and demand with additional within-region transmission.** It is anticipated that Texas will need between 6.8 and 9.4 TW-miles of within-region transmission in 2035 (median 9.0 TW-miles, a 140% increase relative to the 2020 system) to meet moderate load growth and high clean energy growth future scenarios.
- **Meet future generation and demand with additional interregional transfer capacity.** It is anticipated that Texas will need between 4.3 and 12.6 GW of additional transfer capacity in 2035 with the Plains region (median of 9.8 GW, a 1,201% increase relative to 2020 levels) to meet moderate load growth and high clean energy growth future scenarios.

HELPFUL LINKS

- **Read the full study at www.energy.gov/gdo/national-transmission-needs-study**
- **Contact GDO with additional questions: transmission@hq.doe.gov**

FINDINGS AT A GLANCE

Circuit-miles of new or rebuilt transmission lines (≥100kV) energized between 2011–2020 by project driver.

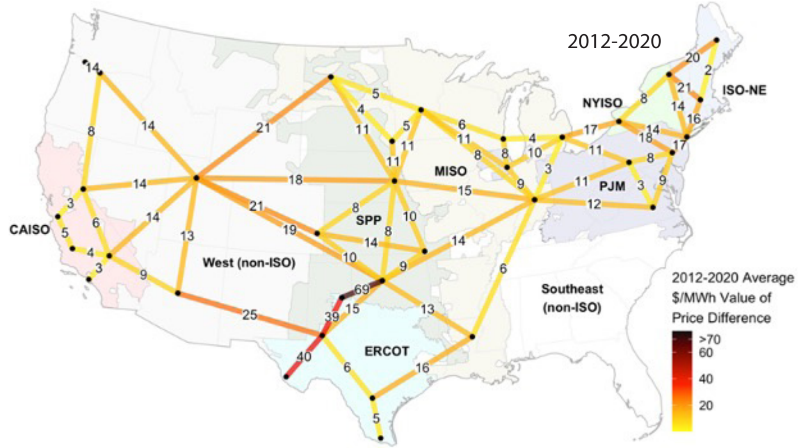


Texas predominantly installed **high-capacity (>230kV) transmission to interconnect generation** between 2011–2014. Projects energized from 2015–2020 were mainly installed to **address reliability concerns**.

Wholesale market price differentials demonstrate a **high value of new interregional transmission** exists **between Texas and the Plains region**.

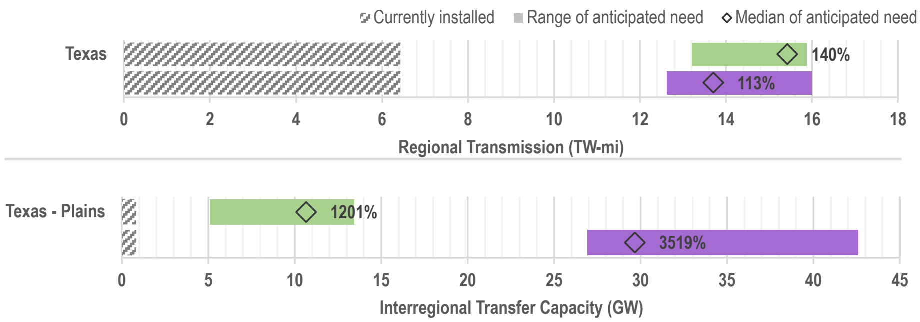
The average marginal value of transmission between Texas and the Plains region from 2012–2020 is equal to $42/MWh.

Congestion value of hypothetical transmission links between select zonal nodes within and across regions.



Note: Wholesale market price data is limited for non-RTO/ISO regions. Absence of data does not necessarily indicate that there is no need for transmission to alleviate congestion and/or unscheduled flows in non-RTO/ISO regions. Findings organized using geographic region nomenclature as described in the Needs Study.
Source: D. Millstein, et al. (2022)

Within-region transmission and interregional transfer capacity need for Texas in 2035
Range of new transmission need for future scenarios with moderate load and high clean energy growth (green, top for each region) and high load and high clean energy growth (purple, bottom). Median % growth compared to 2020 system shown.



Capacity expansion modeling results for the Moderate/High scenario group suggest an anticipated need of **9.0 TW-miles of new within-region transmission by 2035** (140% growth relative to 2020) and **9.8 GW of new interregional transfer capacity with the Plains region by 2035** (1,201% growth relative to 2020).

Median 2035 capacity expansion modeling results for Moderate/High scenario group.

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Appendix B: Comment Synthesis and Resolution

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National Transmission Needs Study

Public Comment Synthesis

Table of Contents

List of Abbreviations

ACC	American Chemistry Council
ACEG	Americans for a Clean Energy Grid
ACORE	American Council on Renewable Energy
ACP	American Clean Power Association
AE	Alliant Energy
AEA	Alaska Energy Authority
AEG	Advanced Energy Group
AES	The AES Corporation
AEP	American Electric Power Service Corporation
AEU	Advanced Energy United
AMP	Association for Modern Powerlines
AMPUA	Arizona Municipal Power Users' Association
AREGCBA	Accelerated Renewable Energy Growth and Community Benefit Act
CDR	carbon dioxide removal
CEBA	Clean Energy Buyers Association
CETA	Clean Energy Transformation Act
CHPE	Champlain Hudson Power Express
CLCPA	Climate Leadership and Community Protection Act
CPNY	Clean Path New York
CREZ	Competitive Renewable Energy Zone
DCC	Data Center Coalition
DER	distributed energy resource
DLR	dynamic line ratings
DOE	U.S. Department of Energy
EDF	Environmental Defense Fund
EEI	Edison Electric Institute
EIPC	Eastern Interconnection Planning Collaborative
EMS	Energy Management System
EPA	U.S. Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas

FAS	Federation of American Scientists
FERC	Federal Energy Regulation Commission
FGRS	Future Grid Reliability Scenarios
FHWA	Federal Highway Administration
FPA	Federal Power Act
GDO	Grid Deployment Office
GEB	Grid-Interactive Efficient Buildings
GET	grid-enhancing technology
GW	gigawatt
HVDC	high-voltage direct current
ICCP	Inter-control Center Communications Protocol
IEDA	Irrigation & Electrical Districts Association of Arizona
IIJA	Infrastructure Investment and Jobs Act
IRA	Inflation Reduction Act
IRPA	Interregional Reliability Planning Assessment
ISO-NE	ISO New England
ITC	International Transmission Company
IRP	integrated resource plan
JHI	Juneau Hydropower, Inc.
JTIQ	Joint Targeted Interconnection Queue
LRTP	Long-Range Transmission Planning
MISO	Midcontinent Independent System Operator
MW	megawatt
NAERM	North American Energy Resilience Model
NCUC	North Carolina Utilities Commission
NEMA	National Electrical Manufacturers Association
NEPA	National Environmental Policy Act
NERC	North American Electric Reliability Corporation
NHA	National Hydropower Association
NIETC	National Interest Electric Transmission Corridors
NJBPU	New Jersey Board of Public Utilities

NREL	National Renewable Energy Laboratory
NYISO	New York Independent System Operator
NWA	non-wire alternatives
NYTOs	New York transmission owners
OSW	offshore wind
PIOs	Public interest organizations
PJM	PJM Interconnection LLC
PPTN	Public Policy Transmission Need
PSEG	PSEG companies
PUCT	Public Utility Commission of Texas
RFP	Request for Proposal
ROFR	right of first refusal
RTEP	Regional Transmission Expansion Plan
RTO	regional transmission organization
SCADA	Supervisory Control and Data Acquisition
SERTP	Southeastern Regional Transmission Planning
SPIGs	Southeast Public Interest Groups
SPP	Southwest Power Pool
SREA	Southern Renewable Energy Association
TVA	Tennessee Valley Authority
TWh	terrawatt-hours
USFS	U.S. Forest Service
VOLL	value of lost load
WATT	Working for Advanced Transmission Technologies Coalition
WECC	Western Electricity Coordinating Council
WIUFMP	Western Interconnection Unscheduled Flow Mitigation Plan
WSM	wide system model

Introduction

On April 6, 2023, the U.S. Department of Energy (Department or DOE) Grid Deployment Office (GDO) published a Notice of Availability of the National Transmission Needs Study and Request for Comment.[1] As mentioned in the Notice, Section 216(a) of the Federal Power Act (FPA), as recently amended by Section 40105 of the Infrastructure Investment and Jobs Act (IIJA), requires DOE to conduct a study of electric transmission capacity constraints and congestion every 3 years. The National Transmission Needs Study (Needs Study or Study) implements that statutory provision and replaces what was formerly known as the National Electric Transmission Congestion Study. Pursuant to section 216(a)(2) of the FPA, the Study would inform any decision to exercise DOE's National Interest Electric Transmission Corridor (NIETC) designation authority. The Needs Study will also inform DOE as it coordinates the use of other authorities and funding related to electric transmission. These include new authorities under the IIJA and existing DOE programs, such as grid-related research and development and financing authorities that support grid infrastructure development.

Comments were accepted by GDO via NeedsStudy.Comments@hq.doe.gov until midnight, April 20, 2023.

GDO asked ICF to provide a synthesis of the comment submissions received in response to the Notice. GDO received a total of 58 submissions. ICF has analyzed all submissions and prepared a narrative summary of the relevant ideas, issues, and concerns expressed by the submissions.

ICF's process for analyzing public comments relies on its commercial CommentWorks® software product, a web-based software solution for analyzing, sorting, tracking, summarizing, and responding to public comments. As a first step, ICF was granted access to the comment mailbox and downloaded all comment submissions to be imported into CommentWorks for analysis. Based on its review of the comments, ICF developed a hierarchical coding structure to include key issues identified in the comments. GDO reviewed this structure and approved its use in organizing the synthesis report. ICF staff then reviewed all unique comments, identifying within each submission substantive excerpts that should be bracketed and coded using the hierarchical structure to associate each bracketed excerpt with the issue(s) to which it applies . ICF staff then synthesized the content from the verbatim excerpt quotes from all submissions into the comment summaries that are included in this document. The comment summaries that follow are organized into issue topic areas, as indicated in the Table of Contents.

DOE reviewed all comments in full in addition to this comment synthesis and considered all comments in full when making decisions about how to revise the Needs Study based on the feedback received. Within each comment topic area, the Department provides a "Department Response," summarizing changes made between the draft Needs Study for public comment (draft Study) and the final version of the Needs Study published in October 2023 (final Study) in response to comments.

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[1] U.S. Department of Energy. 2023. Notice of Availability of National Transmission Needs Study and Request for Comment, 88 Fed. Reg. 13811. Available at https://www.federalregister.gov/documents/2023/03/06/2023-04521/notice-of-availability-of-national-transmission-needs-study-and-request-for-comment.

1. General Comments

1.1. General Support

Several commenters express broad support for DOE's Needs Study. The Arizona Municipal Power Users' Association (AMPUA), Irrigation & Electrical Districts Association of Arizona (IEDA), Advanced Energy United (AEU), and the National Electrical Manufacturers Association (NEMA) note that the Study comes at a critical time as the country works to manage existing planning inadequacies and plan for efficient and cost-effective decarbonization. This section details comments that express support for the Study's methods, content, conclusions, and potential applications.

A few commenters appreciate DOE's approach to identifying national transmission needs. Public interest organizations (PIOs)[2] recognize that literature review, rather than original research, is a standard, scientifically sound methodology. NEMA appreciates DOE's recognition of regional differences, citing that future needs will be informed by market, policy, cultural, and topographical factors. It indicates that different solutions will be required to meet these differing needs, as is reflected in the Needs Study. The Environmental Defense Fund (EDF) supports DOE's iterative approach of alternating between the Transmission Needs and Transmission Planning studies, noting that they can inform and complement one another, as information and data changes.

The AES Corporation (AES) expresses support for DOE's needs-based, technology-neutral approach. AES supports the Needs Study's discussion of transmission needs to (1) increase reliability and resilience, (2) alleviate congestion, (3) reduce unscheduled power flows that are due to system constraints, (4) increase transmission capacity and transfer capability, (5) integrate renewable energy, and (6) support cost-effective generation. AES additionally supports DOE's intention to periodically update the Study.

The American Council on Renewable Energy (ACORE), Edison Electric Institute (EEI), American Clean Power Association (ACP), Southern Renewable Energy Association (SREA), and International Transmission Company (ITC) support the Study's research. ACP writes that the Study's conclusions reflect proper consideration of research and analysis conducted over the past decade. SREA remarks that the Study's research represents a wide range of subject matter expertise, geographic diversity, and concerns related to the power sector. ITC appreciates DOE's thorough consultation with relevant stakeholders throughout the research process. Similarly, EDF concludes that DOE undoubtably met its obligations to consult with affected entities, as defined in the FPA. It cites the 2006 transmission congestion study, in which DOE

[2] Natural Resources Defense Council, Sustainable FERC Project, RMI, Earthjustice, Sierra Club, National Wildlife Federation, Southern Environmental Law Center, Western Resource Advocates, Montana Environmental Information Center, National Audubon Society, and Alliance for Affordable Energy collectively responded to GDO's Request for Comment.

failed to engage with relevant stakeholders,[3] and asserts that, in comparison, the Needs Study engaged in earlier, more comprehensive, and more inclusive engagement.

Some commenters express support for the Needs Study's scope and detail. AEU writes that while there are several studies that analyze specific regions or elements of the grid, the Needs Study presents an appropriate national and regional depiction of transmission needs that cannot be found elsewhere. In opposition to a critique by Southeastern Regional Transmission Planning (SERTP) Sponsors stating that the Study's broad scope extends beyond statutory authority, ACORE strongly disagrees and argues that the draft Study's scope is needed to demonstrate existing infrastructure inadequacies. Similarly, the New Jersey Board of Public Utilities (NJBPU) states that the very purpose of the Study is to identify gaps in existing planning efforts and argues that DOE properly balanced bottom-up and top-down planning efforts. It fully endorses the Study's choice to examine regional and interregional needs, noting that it complements traditional planning processes that prioritize local concerns. SREA and PIOs share this sentiment. SREA specifically notes the Needs Study addresses the limited scope of utility integrated resource plans (IRPs), which often do not consider needs beyond their service territories. In response to a comment by SERTP Sponsors, stating that analyzing forecasted transmission constraints is beyond the scope defined in the FPA, SREA argues that DOE's research predicts future congestion and capacity constraints and excluding these insights from future grid conditions would be negligent.

AMPUA, IEDA, ACP, American Electric Power Service Corporation (AEP), Consolidated Edison Company of New York (Con Edison), Gallatin Power, New York transmission owners (NYTOs), PSEG companies (PSEG), Association for Modern Powerlines (AMP), and PJM Interconnection LLC (PJM) generally agree with the Needs Study's overall findings, such as the need for transmission expansion to manage a changing resource mix, decarbonization efforts, extreme weather events, and existing infrastructure inadequacies. ACP and Americans for a Clean Energy Grid (ACEG) also agree that transmission expansion will encourage a diversified and low-cost future energy mix. They express support for the Study's conclusions across all growth scenarios. In response to a comment by SERTP Sponsors claiming that the existing southeastern transmission system cannot support an additional 2 gigawatts (GW) of generation capacity, SREA argues that this is justification for the Needs Study and evidence that current planning efforts are not sufficient. PJM agrees that there are potential benefits to transmission expansion, under the assumption that it is appropriately planned and sited. EEI notes that the Needs Study's conclusions on the primary needs and challenges facing each region of the country's grid are consistent with findings by local and regional planners and stakeholders in those areas. Similarly, ACEG says that the Study reinforces the findings of multiple experts.

Blue Lake Rancheria Tribe asserts that transmission needs in Tribal lands are critical. It explains that Tribal nations have been widely excluded from national efforts to support electrification in rural and remote areas of the country. Consequentially, the transmission infrastructure serving

[3] California Wilderness Coalition v. United States DOE, 631 F.3d 1072 (9th Cir. 2011).

Tribal lands is at capacity and not prepared to withstand impending climate disasters or to support necessary electrification and clean energy efforts.

Two commenters discuss the need for reliable power and increased transmission infrastructure within their respective industries. The Data Center Coalition (DCC) emphasizes the role of reliable transmission infrastructure in the data center economy. It explains that inadequate transmission infrastructure is already impeding operations, as congestion prevents the utilization of available generation facilities. DCC notes that this is costly, both for individual businesses and workers, and for the national economy. Similarly, the American Chemistry Council (ACC) emphasizes the chemical industry's large demand for electricity, and subsequent transmission needs, warning that demand will likely increase with electrification efforts.

Avangrid, Con Edison, AEU, ACP, AEP, Grid United, National Grid, NYTOs, and AMP specifically support the need for, and benefit of, increased interregional transfer capability. These commenters cite at least one of several factors, including the critical role of interregional transmission infrastructure in the clean energy transition, ensuring reliability, meeting state and federal climate targets, managing growing customer demand, and providing economic benefits. AEU writes that DOE provides indisputable evidence of the need for interregional transmission expansion. Avangrid supports the need for increased international transfer capability and a group of PIOs also support the need for transmission between interconnections and utility service area.

Some commenters confirm the need for transmission expansion in specific regions, including within PJM, in New York and in New England, between New York and New England, and between Canada and New England. Southeast Public Interest Groups (SPIGs) write that the Needs Study accurately portrays future transmission needs in the Southeast and adds that these infrastructure inadequacies are already compromising the region's grid.

ACP and SPIGs agree that transmission deployment is not keeping up with changing needs of the grid. Specifically, the commenters note that despite the importance of interregional transmission, it has received negligible investment in recent years.

Several commenters anticipate that the Needs Study will be useful. SREA states that it provides value to non-regional transmission organization (non-RTO) regions, especially the Southeast. AEU remarks that the Study helps improve transmission infrastructure investments. Con Edison mentions that the Study is helpful to understanding future needs and prompts discussion on the vital role of transmission in clean energy and decarbonization efforts.

ACEG, EEI, Con Edison, DCC, SREA, NYTOs, and PIOs anticipate that the Study will be a beneficial tool for those participating in transmission planning and policymaking. ACEG refers to the Study as a foundational document that each transmission planner, regulator, energy policymaker, and stakeholder should read to better understand the need for and benefits of transmission expansion. AEU states that the Study helps stimulate coordinated regional and interregional planning efforts. SREA indicates that the Study offers context for planners and stakeholders, as they consider current and future grid conditions. NYTOs echo this sentiment, adding that regulators could benefit from its contents. AEU asserts that the Needs Study is an essential benchmark and guidepost in the ongoing effort to mitigate regulatory and planning barriers to transmission development. AEU explains that by creating a set of standard facts relating to regional transfer capability and need, the Needs Study can serve as tool for regional planning entities, as they collaborate and seek mutually beneficial solutions to grid challenges.

Other commenters anticipate that the Study could serve as an important resource for federal programs related to transmission deployment, for both DOE and program applicants. These commenters note that the Study could be valuable in the potential designation of NIETCs and programs funded through the IIJA and Inflation Reduction Act (IRA). ACORE writes that the Needs Study encourages the Federal Energy Regulatory Commission (FERC) to act on the pending proposed rulemakings on regional transmission planning and cost allocation[4] and generator interconnection procedures and agreements.[5]

Lastly, a few commenters support specific aspects of the Study's content. These statements of support are itemized below:

- ACORE and AES support the Study's definition of transmission need.
- AES supports the Study's stated purpose.
- AEP appreciates the Study's acknowledgment that needs will shift over time.
- EEI and Alliant Energy (AE) appreciate the Study's detail on previous and existing capacity constraints and congestion as it provides useful context.
- The Electric Reliability Council of Texas (ERCOT) appreciates the Study recognizes that Texas built more transmission than other regions.
- Utah Public Lands Coordinating Office supports the Study's inclusion of Western Interconnect Unscheduled Flow Mitigation Plan in its discussion of unscheduled flows on Qualified Paths connecting Colorado to its neighbors.

Department Response

The Department thanks the commenters for their comments of general support. The Department did not make any changes in response to these comments.

1.2. General Opposition

This section details comments expressing broad opposition to the Needs Study, as well as objections to the Study's methods and conclusions.

A few individuals express opposition to the basis of the Study and what they view as political or parochial goals of the Study. One individual, Keryn Newman, criticizes the discrepancy between needs identified in the 2020 Congestion Study and the draft Study, stating that in 2020, DOE did

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[4] Federal Energy Regulatory Commission. 2022. Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection, Docket No. RM21-17-000, 179 FERC 61,028. Available at https://www.ferc.gov/media/rm21-17-000.

[5] Federal Energy Regulatory Commission. 2022. Improvements to Generator Interconnection Procedures and Agreements, Docket No. RM22-14-000, 179 FERC 61,194. Available at https://www.ferc.gov/media/rm22-14-000.

not find a need to designate transmission corridors.[6] In contrast, this report finds significant transmission need "in an area so vast that if the DOE were to designate corridors to solve it, the entire continental U.S. would be one gigantic 'corridor.'" Newman concludes that this discrepancy can only be attributed to the fact that the studies "are not based on data and science, but on political goals." Another individual, Janice Cooper, raises similar concerns. Econwerks, states that the Study should be held to much higher scientific standards to meet President Biden's commitment to follow the science. By analyzing existing studies rather than conducting independent research, Econwerks argues that the Needs Study presumes the outcome. Econwerks states that conclusions are not objective, neutral, nor independent and are not anchored in sound science, but instead reflect a "panoply of economic interests with parochial goals."

A couple of commenters express skepticism of the report's utility. PJM questions the Needs Study's role in designating transmission corridors. It argues that the Study's sweeping conclusions are so broad that they could serve as a basis for designating the entire country, or no areas at all, as a transmission corridor. PJM argues that the Needs Study does not offer "the degree of specificity and record" needed to support corridor designation. SERTP Sponsors offer general critique, stating that if the Study "serves more than informational purposes, it must meet a higher bar."

SERTP Sponsors object to the basis of DOE's conclusions, arguing that the research is untethered from state data and planning efforts. Furthermore, SERTP Sponsors state that the Needs Study only considers the benefits of transmission expansion, without a necessary, complementary analysis of transmission costs. Without this analysis, SERTP Sponsors argue that DOE is ill equipped to make transmission corridor designations, which will encourage wide-scale transmission expansion and require significant financial investment. SERTP Sponsors suggest that DOE consult with planning coordinators and transmission planners registered with the North American Electric Reliability Corporation (NERC) to better understand local realities and planning efforts, which include data on transmission costs.

A couple of commenters object to the Study's conclusions. Janice Cooper disagrees with the need for transmission expansion. Keryn Newman argues that transmission cannot solve the needs identified in the Study. Newman explains that regions of the country are already experiencing resource adequacy concerns and increased transmission will only exacerbate the issue, as regions are required to serve both local load and the load of their neighbors. Newman asserts that transmission does not produce electricity, implying that DOE should consider the need for increased generation, rather than transmission capacity.

SERTP Sponsors object to the Study's conclusion that transmission expansion will be necessary and beneficial in the Southeast. They argue that the cost to increase transmission capacity and interregional transfer capability would outweigh the benefits. SERTP Sponsors conclude that low customer costs, low congestion, high reliability, and successful implementation of the

[6] U.S. Department of Energy. 2020. National Electric Transmission Congestion Study, page vi. Available at https://www.energy.gov/oe/articles/2020-national-electric-transmission-congestion-study.

energy policies all indicate that the southeastern grid is working efficiently and does not require build-out. SERTP Sponsors disagree with the Study's claims that utility planning has a limited scope and that the Needs Study is a more thorough assessment of transmission need. They believe their transmission planning, informed by IRP and Request for Proposal (RFP) processes, is more comprehensive.

Department Response

The Department thanks the commenters for their comments of general opposition. The Department believes that analyzing and reviewing previously published scientific and industry data and reports is a valid and valuable methodology to determine the existence of need. Synthesizing existing publications can identify commonalities, contradictions, and gaps in research to help form an evidence-based, comprehensive understanding of transmission need. Leveraging existing research also helps enable DOE to provide timely, relevant insight pursuant to its statutory mandate to conduct a study every 3 years. DOE believes this approach can complement new transmission system modeling and specific project planning, as performed by industry. The Department also believes that this study complements its own modeling and analysis work in the National Transmission Planning (NTP) Study and related work.

The Department notes that findings of transmission need are organized by broad geographic regions—the boundaries of which align with the power grid jurisdictional boundaries—to help focus readers' attention on areas of interest, but these regions do not align with an area that could be designated as a NIETC (pronounced as \NIT-see\). As stated on page 1, the Needs Study does not designate NIETCs. The Department has added content to clarify how the Needs Study interrelates with the NIETC designation processes (pages 1–2).

Changes were made to *Section V.a. Reliability and Resilience* to better explain that transmission is one available solution to address resource adequacy concerns, in addition to generation and demand-side solutions (pages 59–62).

The Department has removed the *Section I. Introduction* passage referenced by SERTP Sponsors regarding utility planning processes from the final Study. The Department maintains that the Needs Study is meant to complement, and not displace, the vital transmission planning performed by utilities. Further, the Department maintains that because the Needs Study is a review of previously performed studies and does not include any new system modeling, reliability, and cost analyses of specific projects—comprehensive components of planning performed by transmission planners—are not within scope of this effort. The Department has added *Section I.a. How to Use This Needs Study* (pages 2–4) to the final Study to further explain how Study findings can complement existing power sector planning efforts.

1.3. Executive Summary and Introduction

This section includes any comments related to the Needs Study's Executive Summary.

AMPUA and IEDA emphasize that electrification could cause power demands to double from 2020 to 2050 and recommend that the Executive Summary adequately stress the need for transmission capacity to manage this demand growth and the lead time for such capacity additions.

CEBA recommends adding a table with regional and interregional transfer capabilities and a summary on the national key takeaways from the Study to the Executive Summary. Additionally, CEBA recommends differentiating existing and anticipated transmission needs to inform prioritization.

Department Response

In response to comments on the draft Study, the Department has restructured the Executive Summary in the final Study to provide more context surrounding national and regional takeaways from each section, including key summary graphics from final Study Sections III–VI. The revised Executive Summary more clearly distinguishes between current and anticipated future needs. New additions include a brief discussion of capacity expansion modeling future scenarios and how increasing power demands are factored into the scenarios.

The Department also inserts a more robust discussion of the need for additional transmission due to load growth (pages 87 and 89) in *Section V.c. Generation and Demand Changes*, which encompasses the impacts of increased electrification of end-use technologies.

1.4. Purpose and Application of the Study

Several commenters urge DOE to provide more context indicating the purpose and application of the Needs Study.

ACP requests clarification on how DOE will use the Study for the Transmission Facilitation Program, public-private partnerships through the Power Marketing Administrations, and other transmission-related loan and grant programs. ACP, AEU, Clean Energy Buyers Association, DCC, EEI, ACEG, and PJM urge DOE to clarify how it will apply the Needs Study to designate transmission corridors. PJM explains that the Needs Study lacks the details necessary to understand transmission needs in the context of corridor designation. For example, it notes that the Needs Study identifies areas in PJM with congestion but does not explain how transmission investments within specific zones could alleviate this. PJM states that the Study's general observations and silence on how these observations relate to corridor designation, "leave the Secretary with little in the way of guidance and support and the public with little information" on how corridor decisions will ultimately be made.

ACEG asks that DOE address if, and how, it plans to facilitate and improve interregional planning efforts. Similarly, ACP urges DOE to explain how it will employ its statutory authority to address the transmission needs identified in the Study. PIOs request DOE recommend additional studies that should follow the Needs Study.

A few commenters request that DOE explain how planners, regulators, and other stakeholders should use the Study. DCC notes that it is unclear how the Study can be used in planning and regulatory processes. It recommends adding a section to the report detailing best practices for using the Study. Similarly, CEBA requests detailed and concrete examples of how states, and regional and local planning entities, can use the Study. ACEG requests guidance on how state and Tribal planners can parse out which of the Study's insights, which are considered at a regional bases, are relevant to their respective planning processes.

ACP and EEI recommend that DOE detail, through guidance or regulations, how applicants to federal transmission programs can use the Needs Study to better their applications. ACP recommends that DOE use the Needs Study to evaluate applications to federal transmission programs, prioritizing applicants whose projects address needs identified in the Study.

Department Response

In response to comments requesting additional context surrounding the purpose and application of the Needs Study, the Department has included additional context in Section I to discuss the purpose of the Study and how the Department plans to utilize its findings. Notably, the Department has added content to clarify how the Needs Study interrelates with NIETC designation processes (pages 1–2).

In response to comments requesting more information about how planners, regulators, states, and other stakeholders should use this Study, the Department has added *Section I.a. How to Use This Needs Study* (pages 2–4) to the Introduction, which discusses how entities may utilize final Study findings and how they can be incorporated into existing transmission planning processes.

The Department does not make additional revisions to the final Study in response to commenter requests for clarity on how DOE will use the Study to guide transmission-related funding. As noted in *Section I. Introduction* (page 1) of the final Study, the Department will use the findings of this Study as it coordinates the use of its authorities and funding that relate to electric transmission, including implementing the many grid resilience and technology investment provisions of the IIJA and the IRA.

1.5. Editorial Changes

Several commenters offer editorial suggestions. This section includes comments related to language, web links, and figures and tables.

ISO New England (ISO-NE) remarks that "the first sentence of the fourth paragraph in Section V.b. of the draft Study regarding the Future Grid Reliability Scenarios (FGRS) may be misleading" and recommends replacing it with:

"ISO-NE (2022) similarly found in their Future Grid Reliability Scenarios (FGRS) that even in a mild weather year, such as the 2019 weather year used in the FGRS, weather events can pose significant challenges to maintaining electrical grid reliability under a high variable energy future."

The Federation of American Scientists (FAS) mentions that the Needs Study's language describing the IRA and IIJA in relation to the Study's modeling scenarios is misleading. Specifically, FAS cites pages 84–85, which define the Moderate/Moderate, Moderate/High, and High/High scenario groups in relation to the passage of the IRA and IIJA and expresses concern that the current phrasing implies that moderate transmission expansion and high renewable penetration are inevitable, given the passing of the IRA and IIJA. They cite Figure VI-6 in the Needs Study to assert that, even with this historic federal legislation, current transmission plans will not be adequate to accommodate an 80% share of renewable energy and "such an outcome must be chosen by multiple actors across all levels of government, industry, and society." FAS encourages DOE to make this clear and provides the following explanation as a possible substitute:

"The Moderate/Moderate scenario group most closely represents the evolution of the power system had IIJA and IRA not been enacted. The Moderate/High group best represents a future power system, now within the range of possibility due to the IRA and IIJA, but still requiring significant action from public, private, and community actors. The High/High group represents a future power system where new clean energy and electrification of demand-side energy policies are enacted."

The Western Electricity Coordinating Council (WECC) offers the following corrections:

- "WECC footprint is not a market." In two instances on page 47, and a third on page 75, it recommends using the term "Western Interconnection" instead of "the WECC" and "WECC region."
- The "Northwest Power Pool (NWPP)" was renamed the "Western Power Pool (WPP)."
- On page 35, the Needs Study references the "2013 WECC Paths Report." WECC offers a link to the updated "2023 Path Rating Catalog."[7]
- On page 32, the "WIUFMP FERC tariff" link does not work. WECC offers "the related Unscheduled Flow Mitigation Plan (WIUFMP), published in 2019'" and explains that it could be "a useful, contemporary reference for inclusion or replacement."[8]

Several commenters provide suggestions on figures and tables. AMPUA and IEDA suggest adding a table to the Study summarizing existing transmission capacity between regions. Comments on existing tables and figures are detailed below.

- **Figure IV-2:** AE recommends describing regional and federal policies, such as FERC Order No. 1000, which could explain these data.
- **Figures IV-2 and IV-3**: AE suggests representing these data, on the proportion of circuit-miles installed by developer type and project driver, at a regional rather than national level. AE explains that doing so would allow for a reader to analyze how regulatory environment and market forces, which differ regionally, shape investment patterns. Additionally, it suggests including the share of data that is related to transmission projects meant to replace existing lines, explaining that these projects are typically excluded from planning processes.
- **Figure IV-3**: AE recommends detailing how MAPSearch defines each project driver. Additionally, it suggests showing the data in Figure IV-3 by developer types, as defined in Figure IV-2 and explaining whether or not these projects were incorporated into regional planning processes. AE also recommends adding additional context to explain the figure's trend, such as the policy and regulation factors that might have contributed

[7] Western Electricity Coordinating Council. 2023 Path Rating Catalog—Public Version. Available at https://www.wecc.org/Reliability/2023%20Path%20Rating%20Catalog%20Public.pdf.

[8] Western Interconnection Unscheduled Flow Mitigation Plan. Available at https://spp.org/Documents/62460/081919%20WIUFMP%20Tariff.pdf.

to the large decrease in the proportion of installed circuit-miles driven by high-capacity projects in 2013.

- **Figure IV-10**: WECC remarks that this figure, illustrating WECC Balancing Authorities, is outdated and provides an updated version as an attachment.
- **Figure V-2**: AMPUA and IEDA, and AE remark that "80%" appears twice on the x-axis. AE recommends adding a line of best fit to summarize the relationship between the share of clean energy and transmission investments. Furthermore, it recommends removing outliers that would skew this line of best fit to ensure it is not misleading. Additionally, AE recommends adding context to explain why estimates in Figure V-2 differ widely and suggests including insights from DOE's report titled *Queued Up… But in Need of Transmission*. AMPUA and IEDA state that while DOE highlights the $500 billion cost of achieving 80% clean energy, the figure and context lack detailed information on regional transmission line construction costs.
- **Table VI-4:** AMPUA and IEDA note that the estimated capacity transfer increase from Southwest to Texas is missing.

Department Response

The Department made several changes based on editorial suggestions received during the public comment period. Specifically, the Department:[9]

- Made corrections to ISO-NE FGRS study reference using suggested language from ISO-NE comments.
- Revised language describing the scenario group descriptions in Section VI.a. of the final Study in response to comments suggesting additional language to clarify the Moderate/High capacity expansion modeling scenario groups. Specifically for the Moderate/High group, the Department has added that while Moderate/High scenarios are now within the range of possibility given current policies, they are not inevitable and will require action (pages 118–119).
- Made changes in response to WECC's suggestion for including new reference to "2023 Path Rating Catalog" (updated Figure IV-14, page 45) updated the broken "WIUFMP FERC tariff" link (page 19), removed references to NWPP, and replaced references of "WECC" to the "Western Interconnection" as appropriate throughout the Study.
- Included additional Figures IV-4 and IV-5 (pages 26–27) in the final Study to display historic developer type data (national level data presented in Figure IV-2 in the draft Study) at the regional and voltage class levels.
- Included additional Figure IV-7 (page 30) in the final Study to display historic transmission driver data (national level data presented in Figure IV-3 in the draft Study) at the regional level.
- Added more information for draft Study Figure IV-3 (final Study Figure IV-6, page 28) on the driver definitions and circumstances behind driver trends in certain regions (pages 27–31).

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[9] Figure labels listed in this section correspond to figure labels as they appear in the final Needs Study.

- Updated Figure IV-10 (now Figure IV-15, page 47) with a more up-to-date WECC balancing authority map.
- Corrected Figure V-2 (now Figure V-6, page 75) x-axis where "80%" appears twice.

The Department notes that the six capacity expansion modeling studies that form the basis of data analysis in Section VI did not model increased transfers between the Southwest and Texas, so there is no data for this potential transfer to add to Table VI-4.

1.6. Other Comments Related to the Content of the Study

EDF suggests that DOE clearly define the term transmission value and its metric for assessing such value. EDF states that the Needs Study references "transmission value" and the "value of transmission," without defining these terms. It argues that this limits the usefulness of certain Study insights, such as declarations of investments that would provide the greatest transmission value. EDF urges DOE to explain whether these terms reflect (1) net or gross benefit value and (2) strictly economic value or an assessment of total benefits, including factors such as reliability and environmental impacts. It also suggests that if the term currently has multiple meanings in the Study, DOE should be consistent and use different language to clarify this difference. EDF asserts that this clarification would make the Study's conclusions more meaningful.

CEBA requests clarification on the meaning of each capacity expansion model scenario group, such as the level and pace of decarbonization in the power system assumed in each group.

AE recommends additional context to inform the reader why the Study's identified transmission needs exist. For example, as noted in Section 1.5, AE notes that Figure IV-3 illustrates a large decrease in the proportion of installed circuit-miles driven by high-capacity projects in 2013 without sufficient explanation. While there are external forces affecting this trend, including policy and regulation, AE is concerned that readers might lack this context. Specifically, it fears transmission owners might use the Study to justify large transmission investments, without implementing the necessary reforms to plan for a cost-effective grid. CEBA recommends adding a section to the Needs Study to describe methodology. It requests an explanation on (1) why DOE chose to examine existing literature, (2) the limitations of the Study, (3) the relationship between the Needs Study and the NTP Study, and (4) how and why the Study might underestimate transmission needs.

National Grid remarks that considering the impacts of specific transmission projects is vital to contextualizing need. Specifically, it argues that projects require detailed modeling and coordination with entities on both sides of the interface to determine the benefits and limitations of a specific upgrade.

AE recommends that the Study include a discussion on how transmission build-out will affect customer costs. It cites an S&P Global Market Intelligence finding on the increase in base rates in Midcontinent Independent System Operator (MISO) as evidence that transmission rates account for a considerable portion of customers' monthly utility bills.[10] AE further notes that the words "rate base" are not mentioned in the Needs Study and asserts that the customer impacts of transmission investments cannot be an afterthought when planning the grid. Keryn Newman criticizes the Study's conclusion that large-scale transmission build-out is cost-effective. Newman cites the Study's "vague claims of 'economies of scale,'" arguing they are never justified and allow DOE to avoid a comprehensive analysis of the cost of transmission.

The Center for Biological Diversity urges DOE to continue to exclude the North American Energy Resilience Model (NAERM) from this planning effort. It references the 2020 Grid Congestion Study,[11] which relied on NAERM. It explains that this model creates a pretext for continued reliance on fossil fuels and supports its omission from the draft Study. It asserts that NAERM should not distract DOE from publishing the Needs Study in a timely manner.[12]

SREA argues that given existing constraints and MISO's current planning efforts, the Needs Study should prioritize connecting MISO South (Delta) and MISO North (Midwest), rather than connecting these regions to the Southwest Power Pool (SPP). SREA cites recent weather events, including the cold weather bulk electric system event in January 2018, Winter Storm Uri in 2021, and Winter Storm Elliott in 2022 to illustrate that existing infrastructure is not equipped to accommodate power flows between the Midwest and Delta regions that are necessary to ensure reliability. Specifically, SREA explains that during these events there was energy in MISO North that was stranded and unable to support load in the Delta region because of system constraints. It also notes that connecting the Midwest and Delta regions will only be valuable if MISO's Long-Range Transmission Planning (LRTP) Tranche 3 effort, which addresses transmission constraints within the Delta region, is successful. SREA explains that congestion in southern Louisiana and southeastern Texas is limiting power flow in the area and contributing to high costs of interconnection. It cites MISO's revised Future 2A forecast, which projects 80 GW of renewable energy, hybrid, and energy storage resources will be deployed in the Delta region by 2037, to further emphasize the need for transmission upgrades within the Delta region.[13]

PJM provides additional context regarding the February 2021 cold snap. During this event, PJM asserts that it supplied an unprecedented amount of electricity to neighboring systems. During

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[10] S&P Global Market Intelligence, Transmission rate base, authorized returns on equity of U.S. utility operating companies in MISO.

[11] U.S. Department of Energy. 2020. National Electric Transmission Congestion Study. Available at https://www.energy.gov/sites/default/files/2020/10/f79/2020%20Congestion%20Study%20FINAL%2022Sept2020.pdf.

[12] The Center for Biological Diversity raised some of these issues in an earlier letter to the agency. See Letter of July 20, 2022, https://www.biologicaldiversity.org/programs/public_lands/pdfs/DOE-Grid-Study-Letter-072022.doc.pdf.

[13] Midcontinent Independent System Operator. 2023. Future 2A Expansion & Preliminary Siting Presentation, slide 8. Available at https://cdn.misoenergy.org/20230310%20LRTP%20Workshop%20Item%2002%20MISO%20Future%202A%20Expansion%20and%20Preliminary%20Siting628178.pdf.

peak hours of the event, PJM's exports totaled to three times higher than the 2020/2021 winter average during peak. Accordingly, PJM concludes that "overall, the grid performed reliably." It also clarifies that transfer limitations during this event can mostly be attributed to constraints in neighboring systems, which could not support a greater volume of imports, rather than facilities in PJM or along the seam. PJM hopes DOE will consider these notes in the Needs Study's discussion of the cold snap.

DataCapable states that there is a need to increase interoperability and shareability of distribution and transmission data, to address a disconnect between utilities, vendors, and distributed energy resources (DERs) manufacturers. It encourages DOE to review Outage Data Initiative Nationwide. Additionally, it emphasizes the need to standardize data sharing between microgrid operations, utilities, and transmission operators to accommodate greater diversity of generating resources on the grid.

SERTP Sponsors remark that the draft Study did not meaningfully address their comments on the consultation draft. Instead of incorporating their suggestions, SERTP Sponsors argue that the draft Study summarizes SERTP Sponsors' concerns in Appendices A-1 and A-2 and cross-references to moderately relevant responses. SERTP Sponsors repeat their recommendations to (1) incorporate state resource projections, (2) include cost analysis, and (3) coordinate EIPC.

SPIGs provide detailed critiques of SERTP Sponsors' comments in Appendix A-2. SPIGs argue that SERTP Sponsors have a vested financial interest in ignoring the needs identified in the Study. SPIGs provide detailed counterarguments to address SERTP Sponsors' comments 43, 55, 83, 97, 118, 128, 129, 132, 147, 148, 149, and 150, as enumerated in Appendix A-2.

Department Response

In general, the term *value* is used colloquially to refer to both quantifiable cost savings and, for example, non-monetized societal benefits. The underlying studies which use this terminology reviewed in the Needs Study may also have their own definition and use. When the term *value* has a specific meaning in the context of an underlying study, it is defined. For example, the research underlying *Section IV.b. Market Price Differentials* defines *value* as "the energy arbitrage potential, that is, the difference in price between two locations," (page 36).

In response to comments requesting more insight into details of the capacity expansion modeling scenario groups, the Department has provided more context and information regarding scenario specifics in *Section VI.a. Included Studies and Scenarios* of the final Study (pages 118–119). The Department has also added a list of scenario names and associated details, including excluded scenarios, to the Supplemental Material (Table S-6, pages 40–43).

As noted in the Department's response to editorial suggestions above and in response to comments requesting additional information about the drivers for historical transmission installation trends, the Department has provided additional context behind historical transmission installation trends between 2011 and 2020 in *Section IV.a. Historical Transmission Investments* of the final Study (pages 28–31).

The Department included a description of its methodology for choosing publications in the opening paragraphs of *Section V. Current and Future Need Assessment and Identification of*

Transmission Benefits through Review of Existing Studies: "The literature includes reports from the U.S. Government, national laboratories, academia, consultants, and a cross section of industry participants that incorporate quantitative and qualitative measures of electricity transmission needs. Reports were chosen on the basis of geographic diversity, diversity among sources, and author subject matter expertise, and to cover a range of critical reliability and congestion issues faced by the transmission system today," (page 52).

In response to comments about the chosen methodologies underestimating transmission need, the Department added several clarifications that full system need may not be captured in the final Study, especially where a lack of reviewable data exists. An example clarification is provided in the Executive Summary: "…there are gaps outside of RTO/ISO regions where information regarding the economic value of congestion is not available; these gaps do not reflect the absence of transmission needs but rather the absence of market data with which to calculate price differentials," (page v).

The Department agrees that additional modeling of the benefits of specific transmission lines is important to understand how they can meet system need. The Department added *Section I.a. How to Use This Needs Study* (pages 2–4) to address this and other comments. Relatedly, cost analysis of any specific project is vital to understanding how benefits may justify the investment costs. As this Needs Study does not analyze the specifics of any individual transmission project, cost analysis is considered out of scope. Example investment costs for system-wide transmission studies were considered in Figure V-6 (page 75).

No new transmission modeling was conducted as part of this final Needs Study. As such, the NAERM model was not utilized in this iteration of the Study.

In response to comments requesting more information regarding transmission limitations between MISO South (Delta) and MISO North (Midwest), the Department has included additional references and context in *Sections V.a. Reliability and Resilience* (page 57–59) and *V.b. Regional Congestion and Constraints* (pages 68–69) to discuss further the Regional Directional Transfer Limit between the Midwest and Delta regions and associated transmission limitations. Section V.a. also includes more discussion on the limitations within the context of recent weather events, including the cold weather bulk electric system event in January 2018, Winter Storm Uri in 2021, and Winter Storm Elliott in 2022 (pages 56–58).

The Department recognizes that PJM was able to export electricity to its neighbors to aid in grid reliability during the February 2021 winter cold event. The cited reports' findings of a lack of interregional interconnections limited the abilities of some regions to maintain reliability during this event are retained in the final Study version. The Department did add the important clarification raised by the commenters that within-region transmission or distribution system upgrades may be necessary to support any given expansion in interregional transmission in a couple of instances. In *Section V.a. Reliability and Resilience* the Department added a reference to a PJM report stating: "In other words, because of the complex nature of transmission flows, interregional transfer capability can be limited by insufficient transmission capacity internal to a region (PJM 2023d)," (page 58). In *Section VI. Anticipated Future Needs Assessment through Capacity Expansion Modeling* the Department added: "Additionally, any portion of these transmission system additions may require associated distribution or transmission system upgrades to support increased energy transfers and, as such, the zonal estimates reported here may underestimate total required system builds. These downstream analyses are critical to the transmission planning process to ensure reliable operation of the grid but are out of scope for the analysis presented here," (page 114).

While important, data sharing and interoperability standards are outside the scope of this effort and are not included in the final Needs Study.

The Department maintains that because the Needs Study is a review of previously performed studies and does not include any new system modeling, the inclusion of additional state resource projections (outside of those already included in the works reviewed), cost analyses of specific projects, and coordination with planning entities in modeling exercises are not within scope of this effort.

1.7. Stakeholder Engagement

As DOE finalizes the Needs Study and plans for corridor designation, EDF encourages DOE to develop a plan for engaging with potentially impacted and historically disadvantaged communities. While EDF appreciates DOE's stakeholder engagement in the preparation of the draft Study, it argues that DOE should carry out stakeholder engagement beyond the statutory minimum before the final Study is published. Particularly, EDF requests that DOE engage with nongovernmental organizations with transmission knowledge, energy justice organizations, and potentially impacted communities. EDF asserts that this will lay the groundwork for relationships with community members that will be necessary in the corridor designation process. The Blue Lake Rancheria Tribe adds that Tribal nations need to be included in transmission planning efforts related to offshore wind (OSW) integration. Specifically, it argues that planners must consider the energy and infrastructure needs of Tribal nations and minimize impacts to Tribal land.

The Advanced Energy Group (AEG) emphasizes the need to educate stakeholders on the need for and benefit of transmission expansion. AEG recommends that this education aligns with the priorities of impacted communities and addresses how transmission can support wealth creation, energy cost burden, and public health concerns. Additionally, AEG urges transmission planners to listen to communities and their experiences and compensate stakeholders for their contributions.

Keryn Newman argues that the Needs Study does not include adequate consultation with landowners, whom Newman identifies as those who will most experience the devastating impacts of transmission development. Newman argues that the Study identifies landowner concerns as a barrier to transmission deployment but does not bother to consult these "barriers" or to devise solutions to mitigate their concerns. For this very reason, Newman also objects to the FERC *Report on Barriers and Opportunities for High Voltage Transmission*, which is cited in the Needs Study.[14] Additionally, Newman argues that landowner interests should be represented on DOE's Technical Review Committee.

CEBA encourages DOE to solicit additional feedback from regional, state, and Tribal entities regarding the Needs Study and possible future improvements. Additionally, it encourages DOE to consult with large energy customers to ensure the Study's projections of load and clean energy demand are consistent with their internal projections. CEBA writes that this step could improve the Study's utility and credibility for industry and government purposes. DCC also recommends engaging with large commercial and industrial customers for future studies. It encourages DOE to convene large energy customers, including representatives from the data center industry, before future publications ensure data are most recent.

SERTP Sponsors encourage DOE to consult with transmission planning entities, like Eastern Interconnection Planning Collaborative (EIPC), before acting on the findings of the Needs Study, which the organization deems as hypothetical transmission needs. SERTP Sponsors urge DOE to consult with planners on their projections of load, resources, and transmission costs, arguing that this information would allow for a more meaningful and holistic assessment of transmission value and help DOE to identify the regions where transmission is most needed.

Department Response

In response to comments from parties requesting additional, targeted stakeholder and Tribal outreach and continued stakeholder engagement, the Department has made additional efforts to engage with entities beyond the Department's consultation with states, Tribes, and regional entities pursuant to Section 216(a) of the FPA, as amended (16 U.S.C. §824p(a)(1)). The Department has continued to accept meeting requests from commenting and interested parties to discuss draft Study findings.

Further, the Department has created regional and national fact sheets to be appended to the final Study and released concurrently to help make Study findings more accessible. The Department hopes the final Needs Study will be used as an educational tool to engage communities in discussion about grid needs. Departmental communications on final Study findings are a tool to solicit additional feedback from stakeholders on what future iterations of the Needs Study should entail.

The Department agrees with commenters that landowner, community, stakeholder, and Tribal engagement is imperative. The Department added *Section V.e. Siting and Land Use Considerations* (pages 95–108) to the final Study on subjects of unique interest to the communities. This section contains discussion of best practices for developers in engaging with landowners and other affected parties.

Additionally, the Department added a new subsection on specific Tribal energy needs to *Section V.c. Generation and Demand Changes*. This subsection (pages 74–89) includes recently

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[14] Federal Energy Regulatory Commission. 2020. Report on Barriers and Opportunities for High Voltage Transmission. Available at https://www.congress.gov/116/meeting/house/111020/documents/HHRG-116-II06-20200922-SD003.pdf.

collected data by the Department's Office of Indian Energy which describe electricity access on Tribal lands.

1.8. Future DOE Action

The Center for Biological Diversity argues that DOE has failed to meet the statutory requirements in previous grid studies and urges DOE to continue the draft Study's efforts. The Center states that Pub Law 109-58 Section 1221 mandates DOE to conduct grid studies every 3 years, and claims DOE has rarely complied. It urges DOE to keep this Needs Study on track to finalize as soon as possible. Furthermore, it urges DOE to adequately address each of the Study requirements detailed in the IIJA.

CEBA suggests that DOE communicate, either directly in the Needs Study or on its website, the iterative nature of the report. Specifically, CEBA requests information on the lessons DOE learned from this iteration, as well as any suggested future studies.

While CEBA understands there are barriers to data collection, specifically in non-RTO regions, it emphasizes that this deficiency hinders the Study and its ability to assess transmission need. It encourages DOE to improve data collection in future iterations of the Needs Study and suggests that DOE organize working groups to brainstorm methods to do so.

ITC asks DOE to support existing planning efforts such as the LRTP and MISO-SPP Joint Targeted Interconnection Queue (JTIQ) Study. National Grid describes its potential project, Twin States Clean Energy Link, which would connect New England to Québec, Canada. It requests DOE's support efforts to increase interregional transfer capabilities, financially and in advocacy.

A couple of commenters discuss DOE's expected NTP Study. CEBA requests clarification on how the Needs Study and NTP Study are related and specifically asks whether the NTP Study will identify solutions to the needs identified in the Needs Study.

EDF offers several suggestions for the NTP Study, itemized below:

- The NTP Study should have a time horizon of at least 20 years to account for the long lead time of transmission development, long-term decarbonization goals, and grid modernization efforts. Furthermore, the NTP Study should consult existing federal, regional, and state planning processes to ensure it accounts for impacts of planned, long-term system evolution.
- The NTP Study should consider a wide range of scenarios that reflect various future grids. EDF suggests DOE look to existing policies and actions at the state, federal, and regional level to design these scenarios. It also urges DOE to account for the impacts of recent climate legislation and to consult with local resources, such as New York Independent System Operator's (NYISO's) annual *Load and Capacity Data Report* (Gold Book),[15] to define energy demand scenarios. Also, EDF notes that extreme weather

[15] New York Independent System Operator. 2022. 2022 Load and Capacity Data Report. Available at https://www.nyiso.com/documents/20142/2226333/2022-Gold-Book-Final-Public.pdf.

events are increasingly common. Accordingly, they state that billion-dollar weather events and climate disasters should be assumed in all scenarios.
- The NTP Study should include a thorough analysis of non-wire alternatives and grid-enhancing technologies (GETs), in which they are not treated as an outlier, but instead entirely incorporated into the NTP Study's assessment.
- The NTP Study should include stakeholder engagement that is at least as inclusive as what was done in preparation for the Needs Study. Additionally, EDF urges DOE to develop a strategy to meaningfully collaborate with energy justice, environmental justice, Tribal, historically disadvantaged, and low-income communities. EDF also expresses support for DOE's suggestion that studies should prioritize renewable energy development in regions experiencing fossil dependence, energy burden, and environmental or socioeconomic vulnerabilities and that transmission should work to mitigate harms to those experiencing high energy burden, frequent or long-duration outages, and high levels of environmental hazards.

AE notes that grid technologies and transmission needs are changing rapidly and asserts that planning processes must become more dynamic and responsive to keep pace. It explains that new grid technologies, such as storage and demand response, can make long-term transmission planning more susceptible to "costly inefficiencies, as the rapidly evolving grid makes some approved transmission projects obsolete before they are even completed." AE expresses support for long-term planning efforts but suggests that long lead time projects are reassessed every 3 years, to ensure assessments reflect the changing realities of the grid.

One individual, Vijayasekar Rajsekar from Institute of Electrical and Electronics Engineers and Pacific Gas and Electric Company,[16] suggests that DOE assess the feasibility of interconnecting the U.S. grid to create a "National Grid" that mitigates reliability concerns and reduces the frequency of blackouts.

Department Response

The Department appreciates comments regarding future DOE action related to the Needs Study. The Department has determined addressing these comments is currently beyond the scope of the 2023 Study.

[16] Rajsekar commented on their own behalf, not on behalf of Institute of Electrical and Electronics Engineers and Pacific Gas and Electric Company.

2. Gaps and Additional Resources

2.1. Legislation and Regulations

AMPUA and IEDA urge DOE to reference FERC Docket No. ER21-1790-003 in the Needs Study. They explain that the Southwest is heavily reliant on transmission from California and FERC Docket No. ER21-1790-003 authorizes CAISO to prioritize California's energy demands over those in the Southwest. Given this, they argue that the Southwest is vulnerable to supply shortages. AMPUA and IEDA encourage DOE to consider this regulation and to include the Southwest's need to reduce dependency on CAISO's transmission infrastructure in the Needs Study.

The Columbia River Treaty Group recommends that DOE review provisions in the IIJA regarding the future of the Canadian Entitlement. It argues that the 1964 Columbia River Treaty, which mandates the United States provide Canada a portion of the power benefit created by Canadian storage dams, is outdated and exceeds what should be returned to Canada. The Columbia River Treaty Group explains that the IIJA includes provisions to rebalance and modernize the Treaty and urges DOE to consider this negotiation in the Study.

Con Edison cites the Climate Leadership and Community Protection Act (CLCPA) as ambitious state legislation that requires "70 percent renewable energy by 2030, 100 percent carbon-free electricity by 2040, and 85 percent economy-wide decarbonization from 1990 levels by 2050. This includes goals of 6,000 megawatts of distributed solar installed by 2025, 3,000 MW of storage installed by 2030, and 9,000 MW of offshore wind installed by 2035." Con Edison clarifies that meeting CLCPA mandates will require transmission expansion in New York, especially to integrate OSW. Hydro-Québec echoes this sentiment, urging DOE to consider New York and New England's ambitious climate legislation. It cites the CLCPA in New York and several clean energy and emission reduction targets in New England.

Similarly, Seattle City Light informs DOE of Washington's passage of the Clean Energy Transformation Act (CETA), which will make previous state projections obsolete. While CETA impacts have not been fully studied yet, it shares that a study is underway by NorthernGrid, which may reveal the legislation's impact on the transmission system.

PIOs suggests that the Needs Study consider the IRA and U.S. Environmental Protection Agency's (EPA) recent proposed rule, *Multi-Pollutant Emissions Standards for Model Years 2027 and Later Light-Duty and Medium-Duty Vehicle*. They cite multiple BloombergNEF articles, which project significant increases in renewable energy, residential electrification, and electric vehicle deployment driven by policy efforts. Accordingly, PIOs encourage DOE to adopt high load and high clean energy assumptions as the Needs Study's base case. Similarly, National Grid emphasizes that the IRA will further accelerate the Northeast region's decarbonization efforts and increase electrification, helping serve as a model for the rest of the country on the impact of the legislation on states' clean energy policies.

PSEG and EEI request that DOE acknowledges FERC's role in transmission planning and investment. EEI objects to the draft Study's statement that "many existing transmission planning processes 'are primarily focused on compliance with NERC and local reliability standards with very limited scopes and planning horizons,'" arguing that it fails to acknowledge FERC's recently proposed transmission planning reforms. EEI cites FERC's Notice of Proposed Rulemaking to change regional transmission planning and cost allocation requirements and notes that such reforms will encourage efficient, cost-effective transmission investment. EEI urges DOE to acknowledge FERC's role in planning reform in the Needs Study. Similarly, PSEG argues that regulatory certainty is crucial to addressing transmission need. It explains that FERC's proposal to remove the RTO adder incentive is a policy that discourages transmission investment.

ERCOT suggests that DOE review recent Public Utility Commission of Texas (PUCT) reforms, stating that the Needs Study's continued reliance on 2021 data contributes to an overestimate of the benefits of increased interregional transmission connections between ERCOT and neighboring regions. ERCOT explains that following the February 2021 winter storm, PUCT adopted reforms to reduce the likelihood and the financial impact of a future such event. Specifically, ERCOT cites the adoption of Tex. Util. Code § 35.0021, Tex. Nat. Res. Code § 86.044, 16 Tex. Admin. Code § 25.55, Tex. Admin. Code § 25.52(h), and Tex. Util. Code § 38.201, which mandate several reliability, resiliency, and planning efforts. In addition, ERCOT references ongoing market reforms, which will cumulatively reduce ERCOT's need for interregional transmission capacity.

Department Response

The Department focused analysis of transmission need on physical limitations of the system and not jurisdictional or regulatory limitations. For this reason, FERC authorities and international treaties were considered out of scope.

Several commenters note recent climate legislation for particular regions and urge the Department to consider implications from new legislation, specific to projected clean energy generation and load changes. The Department did reorganize information in the draft Study and include additional context in *Section V.c. Generation and Demand Changes* to highlight that a) new transmission will be needed to access many clean energy resources (pages 74–79) and b) load growth will require more transmission (pages 87 and 89). These changes include references to 16 additional industry reports not included in the draft Study.

Similarly, PIOs urge the Department to adopt the high load and high clean energy case as the final Study's base case considering the passage of the IRA and EPA's recent proposed vehicle emissions standards. In response to these comments and those referencing recent state climate legislation, the Department states in both the Executive Summary and in discussion of capacity expansion modeling results in Section VI that scenarios including high load growth are more in line with state and utility policy goals in some regions than the moderate load growth scenarios. Results of this scenario group were also highlighted in Figures ES-5 and ES-6 (pages ix–x) in the Executive Summary of the final Study, whereas only results of the moderate load and high clean energy growth scenario group were highlighted in the draft Study. The Department includes additional context regarding the relevance of the high load and high clean energy scenario groups throughout *Section VI. Anticipated Future Needs Assessment through Capacity Expansion Modeling* (notably, pages 119, 143–144). Further, the Department includes a reference to a recently published National Renewable Energy Laboratory (NREL) Study on the Impacts of the IRA on the U.S. power system in *Section VI.a. Included Studies and Scenarios* (page 118).

In response to commenter objections to the Department's characterization of existing planning efforts and recommendations to acknowledge FERC's role in transmission planning and investment, the Department has removed the statement highlighted by EEI and added further clarification in Section I of the final Study (pages 1–2) that this Study will inform existing industry-led transmission planning processes conducted in accordance with FERC regulations and policies. Notably, the Department has added the clarification that "[t]ransmission planning is predominantly conducted today by local utilities, who plan for transmission needs on their respective transmission systems, and 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" (page 2).

The Department maintains that the citations to outages and interregional transfer limitations experienced by ERCOT in the February 2021 winter storm are still relevant and these have been maintained in the final Study. Increased interregional transfer capability is, of course, only one of many solutions that would help prevent similar outages in the future. The Department further clarifies this in the relevant passage of *Section V.a. Reliability and Resilience* by noting other recommended reforms that are unrelated to transmission (page 63).

2.2. Studies and Reports

Approximately 19 commenters suggest additional studies and reports for DOE to consider and revisit before finalizing the Needs Study.

Low-Cost and Reliable Transmission Service

Many commenters like ACORE, AE, ITC, PIOs, Xcel Energy, Vijayasekar Rajsekar, and PJM suggest incorporating the following studies and resources into the Study to enhance the analysis of transmission benefits and provide guidance on low-cost solutions and best practices for ensuring reliable transmission service:

- NREL, *Interconnections Seam Study*[17]
- Grid Strategies, *Enabling Low-Cost Clean Energy and Reliable Service Through Better Transmission Benefits Analysis: A Case Study of MISO's Long-Range Transmission Planning*[18]

[17] National Renewable Energy Laboratory. 2020. The Value of Increased HVDC Capacity Between Eastern and Western U.S. Grids: The Interconnections Seam Study. Available at https://www.nrel.gov/docs/fy21osti/76850.pdf.

[18] Gramlich R. 2022. Enabling Low-Cost Clean Energy and Reliable Service through Better Transmission Benefits Analysis – A Case Study of Miso's Long Range Transmission Planning. Available at https://acore.org/wp-content/uploads/2022/08/ACORE-Enabling-Low-Cost-Clean-Energy-and-Reliable-Service-Through-Better-Transmission-Analysis.pdf.

- Telos Energy, *Multi-Value Transmission Planning for a Clean Energy Future: A Report of the Transmission Benefits Valuation Task Force*[19]
- Brown & Botterud, *The Value of Inter-Regional Coordination and Transmission in Decarbonizing the U.S. Electricity System*[20]
- Grid North Partners, *The CapX2050 Transmission Vision Report*
- Lawrence Berkeley National Laboratory, *Empirical Estimates of Transmission Value using Locational Marginal Prices*[21]
- PJM, *Interregional Transfer Capability Proceeding*[22, 23]
- MISO, *Long-Range Transmission Planning Process*
- MISO-SPP, *Joint Targeted Interconnection Queue Study*

Technology

AE and the WATT Coalition highlight studies that support the expansion and benefits of various transmission technologies. They propose that DOE incorporate The Brattle Group's 2021 *Unlocking the Queue with Grid-Enhancing Technologies*[24] study to further highlight how GETs can significantly increase existing grid capacity. Additionally, the WATT Coalition points out that insufficient attention is given to the increasing utility of GET investments in the Study and provides DOE with case studies showcasing the deployment of GETs in the United States.[25] The

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[19] Energy Systems Integration Group. 2022. Multi-Value Transmission Planning for a Clean Energy Future. Available at https://www.esig.energy/wp-content/uploads/2022/07/ESIG-Multi-Value-Transmission-Planning-report-2022a.pdf.

[20] Brown P, Botterud A. 2021. The Value of Inter-Regional Coordination and Transmission in Decarbonizing the US Electricity System, p. 115. Available at https://www.sciencedirect.com/science/article/pii/S2542435120305572.

[21] Lawrence Berkeley National Laboratory. 2022. Empirical Estimates of Transmission Value using Locational Marginal Prices, p. 3. Available at https://eta-publications.lbl.gov/sites/default/files/lbnl-empirical_transmission_value_study-august_2022.pdf.

[22] Federal Energy Regulatory Commission. 2022. Staff-Led Workshop on Establishing Interregional Transfer Capability Transmission Planning and Cost Allocation Requirements held December 5–6, 2022, Docket No. AD23-3-000. Available at https://www.ferc.gov/news-events/events/staff-led-workshop-establishing-interregional-transfer-capability-transmission.

[23] Federal Energy Regulatory Commission. 2023. Establishing Interregional Transfer Capability Transmission Planning and Cost Allocation Requirements, Notice Requesting Post-Workshop Comments, Docket No. AD23-3-000. Available at https://ferc.gov/media/notice-requesting-post-workshop-comments-docket-no-ad23-3-000.

[24] Tsuchida T, Ross S, and Bigelow A. 2021. Unlocking the Queue with Grid-Enhancing Technologies. Available at https://watt-transmission.org/wp-content/uploads/2021/02/Brattle__Unlocking-the-Queue-with-Grid-Enhancing-Technologies__Final-Report_Public-Version.pdf90.pdf.

[25] Available at https://view.officeapps.live.com/op/view.aspx?src=https%3A%2F%2Fwatt-transmission.org%2Fwp-content%2Fuploads%2F2023%2F04%2FUS-GETs-Case-Studies.xlsx&wdOrigin=BROWSELINK.

WATT Coalition also suggests that DOE reference a 2019 paper[26] to address barriers hindering the optimal and effective utilization of existing and future transmission infrastructure.

Offshore

ACORE, PIOs, and SPIGs request DOE include the following relevant studies regarding the benefits of OSW integration:

- The Brattle Group, *The Benefit and Urgency of Planned Offshore Transmission: Reducing the Costs of and Barriers to Achieving U.S. Clean Energy Goal*[27]
- Smith et al., *Offshore Wind Transmission and Grid Interconnection across U.S. Northeast Markets*[28]
- DOE, *Atlantic Offshore Wind Transmission Literature Review and Gaps Analysis*[29]

Given that the *Atlantic Offshore Wind Transmission Study* anticipates a significant amount of OSW in the Northeast and discusses the associated challenges, National Grid recommends that DOE consider the interaction between NREL's study and the results of the Needs Study, particularly regarding interregional transfers. Additionally, PSEG suggests that DOE update the Study to incorporate the 40 recommendations included in the updated *Atlantic Offshore Wind Transmission Action Plan*.

Extreme Weather Events

Many commenters provide materials to better capture extreme weather events in the Study.

CEBA notes that the Study may potentially underestimate transmission needs, as it fails to consider the impact of recent events, such as Winter Storm Elliott. ACORE and SPIGs recommend including Grid Strategies' *The Value of Transmission During Winter Storm Elliott*[30] to showcase the benefits of interregional transmission during extreme weather events. Specifically, SREA suggests that DOE incorporate Grid Strategies' approach in determining the value of transmission. SREA mentions that Grid Strategies utilizes wholesale power prices at the

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[26] Tsuchida T, and Gramlich R. 2019. Improving Transmission Operation with Advanced Technologies: A Review of Deployment Experience and Analysis of Incentives. Available at https://watt-transmission.org/wp-content/uploads/2019/06/brattle-grid-strategies-paper-improvingtransmissionoperationwithadvancedtechnologies.pdf.

[27] Pfeifenberger J, DeLosa III J, Bai L, Plet C, Peacock C, Nelson R. 2023. The Benefit and Urgency of Planned Offshore Transmission: Reducing the Costs of and Barriers to Achieving U.S. Clean Energy Goals. Available at https://www.brattle.com/wp-content/uploads/2023/01/Brattle-OSW-Transmission-Report_Jan-24-2023.pdf.

[28] Smith K, Lenney S, Marsden O, Kates-Garnick B, Stanković A, Hines E. 2021. Offshore Wind Transmission and Grid Interconnection across U.S. Northeast Markets. Available at https://createsolutions.tufts.edu/wp-content/uploads/2021/08/OSW-Transmission-and-Grid-NE.pdf.

[29] U.S. Department of Energy. 2021. Atlantic Offshore Wind Transmission Literature Review and Gaps Analysis. Available at https://www.energy.gov/sites/default/files/2021-10/atlantic-offshore-wind-transmission-literature-review-gaps-analysis.pdf.2021.

[30] Goggin M, and Zimmerman Z. 2023. The Value of Transmission During Winter Storm Elliott. Available at https://acore.org/wp-content/uploads/2023/02/The-Value-of-Transmission-During-Winter-Storm-Elliott-ACORE.pdf.

interfaces between TVA (Tennessee Valley Authority) and Duke Energy with MISO and PJM, then applies a value of lost load (VOLL) of $9,000 to determine the value of transmission, which factors in the value of transmission during extreme weather events.

For additional reading, Vijayasekar Rajsekar suggests that DOE consider ERCOT's letter to Members of the Texas Senate and the Texas House of Representatives regarding generator outages during the cold weather event in February 2021.[31] Additionally, Rajsekar provides *Outages and Curtailments During the Southwest Cold Weather Event of February 1–5, 2011, Causes and Recommendations*.[32]

Other Topics

TDI New England disagrees with the Needs Study's reference to Brinkman et al. in Section VI.d., explaining that the statement about significant international transfer capacities between Canada and New York and New England not arising until 2040 is incorrect. TDI New England points out that New England Clean Power Link is a fully permitted transmission project, situated to commence and complete construction in a timely manner, which will enable considerable international transfer capacities well before 2040. Similarly, NYTOs disagree with DOE's statement, as they expect Champlain Hudson Power Express (CHPE) to be operational by spring of 2026.

The Blue Lake Rancheria Tribe suggests DOE update outdated references to clean energy and economic potential statistics. For instance, markets with recent increases in energy costs and constraints have the potential to develop significant amounts of clean energy as both economic enterprises and economy-enabling infrastructure.

An individual commenter, William Driscoll, proposes that DOE add a discussion on the benefits of flexible demand, citing two of his published stories: *Real-time pricing that balances renewables could save $33 billion per year, study finds*[33] and *California rulemaking to pursue demand flexibility through dynamic pricing*.[34]

[31] Electric Reliability Council of Texas. 2021. ERCOT letter to Members of the Texas Senate and the Texas House of Representatives regarding Generator outages during February 2021 cold weather event, dated March 4, 2021. Available at https://www.ercot.com/files/docs/2021/03/04/ERCOT_Letter_Re_Feb_2021_Generator_Outages.pdf.

[32] Staff of the Federal Energy Regulatory Commission and the North American Electric Reliability Corporation. 2011. Outages and Curtailments During the Southwest Cold Weather Event of February 1–5, 2011, Causes and Recommendations. Available at https://www.ferc.gov/sites/default/files/2020-04/08-16-11-report.pdf.

[33] Driscoll W. 2022. Real-time Pricing that Balances Renewables Could Save $33 Billion per Year, Study Finds. Available at https://pv-magazine-usa.com/2022/06/15/real-time-pricing-that-balances-renewables-could-save-33-billion-per-year-study-finds/#:~:text=Markets-,Real%2Dtime%20pricing%20that%20balances%20renewables%20could%20save%20%2433%20billion,bills%2010%25%20to%2017%25.

[34] Driscoll W. 2022. California Rulemaking to Pursue Demand Flexibility through Dynamic Pricing. Available at https://pv-magazine-usa.com/2022/07/22/california-rulemaking-to-pursue-demand-flexibility-through-dynamic-pricing/#:~:text=Demand%20flexibility%20would%20allow%20consumers,%E2%80%9Csending%20prices%20to%20devices.%E2%80%9D.

Gallatin Power recommends reviewing the draft *CAISO 2022–2023 Transmission Plan* to highlight constraints on Paths 46 and 66.

Xcel Energy is concerned that DOE did not review reports developed by utilities, such as Grid North Partners' *The CapX2050 Transmission Vision Report*, suggested above.

Juneau Hydropower, Inc. (JHI) advocates for the inclusion of DOE's *Hydropower Vision Chapter 3, Assessment of National Hydropower Potential*.[35] JHI elaborates that it is important to recognize that water is much denser than air and can serve as a powerful energy source for the country and help meet the Nation's economic, energy, and national security objectives.

Vijayasekar Rajsekar includes a list of further reading suggestions for DOE, including *The U.S. May Finally Get a Unified Power Grid*[36] by Kumagai, J. and the *Continental Europe Synchronous Area Separation on 8 January 2021*[37] by European Network of Transmission System Operators for Electricity (ENTSO-E).

SPIGs recommend that DOE consider its Initial Comments in Response to FERC Notice of Proposed Rulemaking in Docket No. RM21-17-000[38] for further insights.

Department Response

Whereas Section V of the draft Study references over 50 different industry reports published in the past 5 years, the final version references more than 100 recent reports to highlight the historical and anticipated drivers of transmission needs, the multiple benefits that additional transmission infrastructure can provide to consumers, and the challenges of expanding the Nation's electric transmission infrastructure. A complete list of the reports reviewed for incorporation into Section V of the final Needs Study are listed in Table S-4 of the accompanying Supplemental Material document (pages 13–24). The Department notes that several of the studies referenced by commenters were already included in the draft Study. Many of the studies added to Section V of the final Study were specifically suggested by commenters, which include, but are not limited to:

- NREL, *Interconnections Seam Study*
- Grid North Partners, *The CapX2050 Transmission Vision Report*
- MISO, *Long-Range Transmission Planning Process*
- CAISO, *2022–2023 Transmission Plan*

[35] U.S. Department of Energy. 2016. Hydropower Vision Chapter 3, Assessment of National Hydropower Potential. Available at https://www.energy.gov/node/1922621/.

[36] Kumagai J. 2015. The U.S. May Finally Get a Unified Power Grid (*IEEE Spectrum Magazine*). Available at https://ieeexplore.ieee.org/document/7367461.

[37] European Network of Transmission System Operators for Electricity. 2021. Continental Europe Synchronous Area Separation on 8 January 2021, Interim Report. Available at https://eepublicdownloads.azureedge.net/clean-documents/Publications/Position%20papers%20and%20reports/entso-e_CESysSep_interim_report_210225.pdf.

[38] Southeast Public Interest Groups. Initial Comments in Response to Federal Energy Regulatory Commission Notice of Proposed Rulemaking in Docket No. RM21-17-000.

- The Brattle Group, *The Benefit and Urgency of Planned Offshore Transmission: Reducing the Costs of and Barriers to Achieving U.S. Clean Energy Goal*
- DOE, *Atlantic Offshore Wind Transmission Literature Review and Gaps Analysis*
- Grid Strategies, *The Value of Transmission During Winter Storm Elliott*

In response to the Blue Lake Rancheria Tribe suggestion for DOE to update outdated references to clean energy and economic potential statistics on Tribal lands, the Department has added an additional subsection (pages 84–86) to provide more context surrounding unique Tribal energy and transmission needs. The subsection addition includes preliminary results from a Department-conducted survey of Tribal access to reliable electricity as directed by the Consolidated Appropriations Act, 2021 (pages 84–85).

Many commenters suggested news articles for inclusion in the final Study. Except in rare circumstances for which a substitute reference could not be found, these articles were omitted from review and instead a published report or industry reference on the suggested topic was used. Highly technical journal publications that are not accessible to the wider public were similarly omitted from this analysis.

2.3. Data and Assumptions

Approximately 35 commenters suggest changes to data and assumptions used in the Study.

Seattle City Light finds that the transmission challenges related to the Canadian Entitlement Return and other flows between British Columbia and the Pacific Northwest have not been considered in the Study and stresses the importance of recognizing the need for solutions that address the transmission issues between Canada and the Northwest. Seattle City Light states that British Columbia also supplies electricity to California for many hours of the year and dealing with regional power flows have been challenging since the early 2000s when the first Puget Sound Area – Northern Intertie curtailments occurred.

Alaska Energy Authority (AEA), National Hydropower Association (NHA), and JHI urge DOE to include Alaska in the Study. As JHI notes, while Alaska aims to reduce energy costs by transitioning to renewable energy sources and improving transmission reliability, the state's transmission infrastructure is severely lacking compared with the contiguous United States. NHA suggests including an Alaska appendix to address the state's significant transmission needs, considering its unique characteristics. JHI points out that if the Study's purpose is limited in scope, then DOE should create an Alaska Annex. NHA suggests the Study recognize Alaska's potential to export hydropower to the Yukon or British Columbia through future transmission links. However, NHA notes hydropower development requires markets and transmission infrastructure, and high transmission costs can hinder viability without federal or other subsidies. Moreover, JHI states that federal authorization for a Southeast Alaska Intertie in 2000 to interconnect the region of the state with high-voltage transmission lines have still not yet been appropriated by Congress. It notes that the Alaska Railbelt region also requires enhancements to alleviate congestion, enhance redundancy, and accommodate current and future electricity generation. It also believes it is crucial to view Alaska's transmission needs from an environmental and social justice perspective, in addition to economic and national security.

DCC mentions that the data center industry has experienced the impact of inaccurate or underestimated forecasts of energy demand growth drivers. It stresses the importance of ensuring that load forecasts consider a variety of factors that drive demand, like electric vehicle growth, electrification, and other industry trends. Similarly, one individual, Martyn Roetter, adds that it is unclear whether the Study has thoroughly evaluated the overall demand for clean electricity, including the potential load from indirect uses like green hydrogen and low carbon fuel production, and the potential load from carbon removal systems.

Referring to its recent study, the *Energy Transition Report*, which examines the impact of industry trends and federal decarbonization policies in the PJM Region, PJM urges DOE to consider four trends that pose reliability risks during this transition:

- Electricity demand is increasing due to electrification and the growth of data centers in the region.
- Thermal generators are retiring quickly due to government and private sector policies and economic factors.
- Retirements may outpace the construction of new resources, with potential long-term consequences.
- PJM's interconnection queue primarily consists of intermittent and limited-duration resources, which require more capacity to replace thermal generation.

Econwerks states that the report fails to mention energy efficiency and does not sufficiently discuss demand-side management. Econwerks also indicates that there is no mention of the use of real-time pricing to ration demand, load modifying programs, or VOLL in the draft Study.

Utah Public Lands Coordinating Office mentions that the Study does not consider major transmission lines like Energy Gateway South and TransWest, nor does it address the need for substations and supporting infrastructure to accommodate the growing use of solar, wind, and geothermal energy. Xcel Energy notes there are ongoing efforts that might address some of the conclusions from the Study. It recommends considering the current planning assessments, known projects, and depicting the outcomes as a gap and needs assessment. It asks for clearer understanding of how these plans align with the analyzed scenarios to determine realistic paths forward. It offers regional transmission plans, IRPs, and other analyses conducted by utilities that could provide better information for comparing these plans.

CEBA, SPIGs, and SREA all discuss the need for additional data in the Needs Study. CEBA recognizes that the lack of data availability on local, regional, and interregional congestion and capacity constraints, specifically in non-RTO regions in the West and the Southeast, poses challenges to the comprehensive nature of the Study. CEBA encourages DOE to improve data collection for future iterations of the Needs Study by leveraging its technical and convening capabilities to set up working groups to address concerns and barriers. SPIGs supports DOE's interest in using quantitative measures to identify existing transmission needs. As evident from the gaps in draft Study Figures IV-4 through IV-6, SPIGs highlight the limitations that are due to the absence of an independent wholesale energy market and the associated price transparency in the Southeast. SPIGs also observe that the primary metric used in the Study to evaluate needs—market price differentials—excludes the Southeast entirely. SREA encourages DOE to work with SERTP utilities to obtain nodal data so more specific transmission analysis can be conducted.

ERCOT argues that DOE fails to fully account for data that may skew overall historical trends. For example, ERCOT questions DOE's use of 2021 price data in its analysis since it includes Winter Storm Uri, which ERCOT argues is a statistically outlying event. Although ERCOT notes that the Study tries to reduce its emphasis on 2021 data by introducing data from additional time periods, ERCOT insists that continued reliance on it still overestimates the benefits of increased interregional transmission connections between ERCOT and other regions. ERCOT additionally notes that Texas regulators have enacted reforms since the storm that would reasonably be expected to reduce the likelihood and the financial impact of a similar event.

Con Edison does not oppose the Needs Study's suggested GW increase in the interregional transfer capacity assessment but requests additional transparency regarding DOE's data to confirm whether it is up to date. Con Edison notes that it is important to confirm the most up-to-date information, as it will ensure the accurate assessment of transmission needs.

Several commenters emphasize the need to consider resilience in regional planning. Grid United recommends that DOE continue exploring methodologies that can assess the impact of extreme weather events. One approach it mentions is to conduct Loss of Load Expectation studies, which involve more advanced modeling to account for weather volatility. It indicates that qualitative assessment of past extreme weather events, like storms Uri and Elliott and the California heatwave, could also be conducted if Loss of Load Expectation studies are too quantitatively rigorous. PJM notes several emerging system conditions that already present challenges to reliable system operations, including cyberattacks and shifts in the generation fleet. In assessing needs for the Southeast, SREA highlights the importance of considering any relevant data from the joint FERC/NERC inquiry into Winter Storm Elliott, initiated on December 28, 2022.

Some commenters point to the absence of state-level data or assumptions. Utah Public Lands Coordinating Office mentions that the national assessment did not consider the state-level studies. Utah Public Lands Coordinating Office cites studies like the *Utah Transmission Study* that highlight potential capacity issues as Utah's population grows and electricity demand increases, especially during extreme temperatures and studies that conclude that Utah would not gain many benefits from joining ISO/RTO because of its already low electricity prices and reliable grid. Utah Public Lands Coordinating Office also emphasizes that there are concerns about increasing energy costs when moving east from Utah, like seen in draft Study Figure IV-6, suggesting a need for new infrastructure to meet future energy needs in those areas. The Utah Public Lands Coordinating Office encourages DOE to consider the goals, objectives, and policies of energy solutions and align them with those at the state and local planning levels, which will help avoid legal conflicts and speed up the completion of energy projects.

SERTP Sponsors suggest the Study would benefit from including more information from state-regulated processes, particularly regarding the bottom-line impact on customers. They indicate the FPA reserves exclusive authority for the states to regulate facilities used for electricity generation, which includes making decisions about planning and resources for utilities.

Therefore, it is unclear to them why the Study independently makes assumptions about load and resources based on various studies as opposed to using state-determined resource decisions. SERTP Sponsors recommend that DOE collaborates with the EIPC to include the resource decisions made by states in their planning efforts.

Econwerks and Keryn Newman raise concerns regarding the report's presumption that all congestion can be addressed and eliminated. Econwerks suggests that the Study should differentiate between economically justified expansion of renewable technologies and their impact on the grid. Econwerks cautions against treating congestion as the sole driver for transmission expansion, as it could lead to predetermined conclusions and excessive infrastructure development. Monitoring Analytics notes that because the geographic distribution of congestion is dynamic, constructing transmission to address a specific congestion pattern does not make sense unless the technology can be easily moved to new locations as conditions change.

Xcel Energy provides suggestions for improving discussions on curtailment, including acknowledging additional reasons for why resources may be curtailed outside of transmission constraints and recognizing the value gained from reduced curtailment. It argues that allowing some level of curtailment in a higher variable energy future may be more cost-effective than efforts to eliminate curtailment entirely. Xcel also references MISO's RIIA, which indicates that renewable resources operating below maximum capacity can improve system stability. Finally, Xcel Energy calls for additional context on the cost-benefit balance of addressing certain transmission constraints as other constraints are mitigated.

Department Response

The Department focused analysis of transmission need on physical limitations of the system and not jurisdictional or regulatory limitations. For this reason, international agreements were considered out of scope.

In response to commenters requesting more information regarding the need for transmission in Alaska, the Department has incorporated both Alaska and Hawaii into the final Study. Historic Alaskan transmission installations[39] were incorporated into *Section IV.a. Historical Transmission Investments* (pages 20–31). Additional discussion of transmission needs of both states can be found throughout *Section V. Current and Future Need Assessment and Identification of Transmission Benefits through Review of Existing Studies*. Eleven additional references to the Alaskan or Hawaiian power grids were reviewed for inclusion in this section, which can be viewed in Table S-4 of the accompanying Supplemental Material document (pages 13–24). Capacity expansion modeling data are limited for Alaska and Hawaii. As a result, neither Alaska nor Hawaii was incorporated into the analysis in *Section VI. Anticipated Future Needs Assessment through Capacity Expansion Modeling*.

[39] Historic Hawaiian transmission investments were not intentionally omitted from this section, but no transmission investments that met the threshold for inclusion in the analysis were identified in Hawaii.

Various commenters suggested the draft Study underestimates energy demand growth drivers or suggested a high load growth and high clean energy penetration scenario would be a more appropriate base case considering the passage of IRA and IIJA. In response, the Department has expanded Section V.g. of the draft Study to encompass more than just implications from and factors leading to increased electrification to include more discussion. The subsection, now included in pages 87 and 89 under *Section V.c. Generation and Demand Changes*, discusses additional factors outside of increased end-use electrification that would serve to increase demand, including emerging industries such as data centers, chemical production, hydrogen production, and direct air capture, among other drivers. Several transmission planning reports that identify the emergence of high-demand industrial growth were also added to the report. See Department Response in Section 4.4 of this comment synthesis for a discussion of how increased demand due to hydrogen production and carbon dioxide removal is considered in Section VI.

Further, as discussed in Section 2.1 above of this comment synthesis, the Department includes additional context regarding the relevance of the high load and high clean energy capacity expansion scenario group included in the final Study. Findings for this scenario group are highlighted alongside those for the moderate load and high clean energy scenario groups in study graphics, including Figures ES-5 and ES-6 (pages ix–x) of the Executive Summary. The Department also states in both the Executive Summary and in discussion of capacity expansion modeling results in Section VI that scenarios that include high load growth are more in line with state and utility policy goals in some regions than the moderate load growth scenarios (pages 118–119).

The Department also addresses suggestions from commenters to provide more information with respect to the needs of certain regions and states. In response to PJM's comment requesting more nuanced discussion about reliability concerns given a shifting generation mix, the Department has incorporated suggested references and expanded discussion of reliability needs in *Section V.a. Reliability and Resilience*, notably on pages 54–55, 62–63, 87, and 89. The Department additionally included five PJM references in the final Study that were not included in the draft Study.

While important to power sector evolution, the Department deemed demand-side solutions, including energy efficiency, to be outside the scope of this National Transmission Needs Study. The Department does acknowledge the importance of demand-side solutions in the final Study, however. In *Section V.b. Market Price Differentials* the Department states "[o]ther strategies (e.g., energy efficiency or new low-cost energy supply resources) could also help lower localized high prices. The specific solutions that work for each locality might be unique to that community," (page 34). Additionally, the Department does briefly discuss the role of energy efficiency in power sector development in *Section V.c. Generation and Demand Changes*, notably on page 87. Demand response solutions are also identified as a potential alternative transmission solution on page 90.

Similarly, market-based solutions were deemed out of scope except as they impact the transmission system. The intersection of markets and transmission congestion are discussed throughout Section V, and at length in *Section V.b. Regional Congestion and Constraints* (pages 64–74).

The Department emphasizes that the Needs Study is not meant to identify particular solutions in *Section I. Introduction*. As such, the Department made a general practice of not identifying specific transmission projects in the final Study, and therefore projects referenced by commenters like Utah Public Lands Coordinating Office and Xcel Energy are omitted from the final Study. Further, the Department uses *transmission* in a technology-agnostic way throughout the final Study, whereby individual transmission elements necessary for system function, such as substations, are not called out specifically.

The Department acknowledges that lack of data access makes determining transmission need difficult in some regions, particularly in the non-RTO/ISO regions like the Southeast and Florida. Absence of data does not necessarily indicate that there is no need for new transmission. The Department has added several acknowledgments of this point by stating throughout the Study that the absence of data does not necessarily indicate that there is no need for new transmission. This acknowledgment is notable on all summary figures, including Figure ES-7 (page xi). The Department draws on several different analyses to determine need, not just the market price differentials analysis, a point that was additionally made clear in the summary figures.

ERCOT notes the discussion of price data in ERCOT and SPP includes data from 2021 Winter Storm Uri, an event that is an outlier among historical data. The Department believes retaining analysis of this event is important given the immense implications it had on the power sector and electricity consumers. The Department does include additional discussion in *Section IV.b. Market Price Differentials* of the final Study (pages 39–42) describing how extreme events, such as Winter Storms Uri and Elliott, can produce price spikes in affected areas. This section also analyzes the portion of total transmission congestion value attributable to high-value hours or extreme conditions between 2012 and 2021 to provide more context.

In response to comments requesting additional examples of extreme weather events and associated impacts to the grid, the Department has added new references to Section V to discuss events such as extreme heat events in California and the Northwest, the 2014 polar vortex impacts to the Midwest and northeastern U.S., and the 2018 “bomb cyclone” cold weather event, among other events. Nearly 20 different industry and consultant reports were added to the final Study to capture the impacts of extreme weather.

In response to suggestions to provide more state-level data, the Department has incorporated various studies focusing on transmission needs at the state level throughout Section V. Xcel Energy, for example, suggested discussing benefits of interconnecting Texas and the Mountain regions. The Department notes that while benefits of increased interconnection with neighboring regions are discussed elsewhere in Section V, none of the studies included under Section VI’s capacity expansion modeling analysis considered new future connections between Texas and the Mountain or Southwest regions.

The Department agrees that alleviating all transmission congestion—and, related, all generation curtailment—is economically inefficient and the Study does not suggest this strategy should be undertaken. This caveat is appropriately noted in *Section V.b. Regional Congestion and Constraints*: “New deployment of transmission, along with storage and other alternative transmission solutions, can alleviate congestion. If a transmission facility is being considered for the sole purpose of alleviating congestion, the cost of the project would need to be less than the congestion costs that are alleviated for the project to be financially viable,” (page 64). Similarly, the Department agrees that there are many causes for long interconnection queues aside from an inadequate access to transmission. This point is appropriately caveated in *Section IV.d. Interconnection Queues* in the passage that begins: “There are numerous drivers of these trends. While lack of access to transmission is a major barrier, there are many potential reasons that proposed power plants do not always move rapidly to the construction phase…” (page 48).

2.4. Methodology and Modeling

Approximately 32 commenters provide insights related to the Need Study’s methodology and modeling.

Modeling Methodology and Analysis

Many commenters shared their opinions and suggestions on DOE’s modeling methodology and analysis in the Study.

Both PJM and SERTP Sponsors state that the Study fails to address concerns about resource adequacy, especially the potential for certain regions to shift their resource adequacy responsibilities to neighboring regions through interregional transmission. Econwerks suggests that DOE conduct a thorough investigation of resource adequacy separate from those conducted by reliability coordinators, RTOs, consultants, and policy influencers who all have an economic interest in grid build-out. Econwerks remarks that DOE should rely on an independent study of transmission needs that is academically rigorous and peer reviewed to ensure scientific accuracy and acceptance by the general public.

Grid United recommends DOE evaluate any need for expanded regional transmission networks to ensure deliverability of resources from large energy zones, which follows the study methodology used by RTOs and utilities when assessing their generator interconnector processes. AEU states that while interregional projects are more challenging to build, DOE should not ignore the significant benefits provided by regional transmission lines, which can face many of the same barriers to construction.

SREA states that given the evolving generation mix, it is important to conduct a more thorough analysis at both regional and interregional levels. SREA states that this is important because not all utilities—like those in Alabama, Florida, and Texas—publish IRPs. SREA acknowledges that while IRPs may be helpful data inputs, they are not the only sources for evaluating future load, retirements, and generation changes. Nevertheless, SREA encourages DOE to collaborate with all utilities to collect IRP data and utility goals to inform future sensitivities and studies in the future.

Xcel Energy suggests that instead of generic solutions, the Study could focus on discussing the benefits of increased connectivity between areas. It indicates that the general nature of the solutions provided does not motivate them to implement the findings of the Study.

Keryn Newman states the Study touts bidirectional power trading between regions, but it overlooks the challenges of interregional merchant transmission, which rely on contracted customers. Newman states that without firm customers, merchant transmission has no revenue stream and is uneconomic to build.

According to NEMA, the largest issue confronting transmission development is less the technical limits of transformers, but rather in the difficulty of obtaining an adequate supply of transformers. NEMA suggests this should be considered as a significant need and included as a study criterion. NEMA adds that the availability of critical products is necessary for the functioning of the grid at the state and local levels, particularly for end-users, and should be considered in transmission planning.

ACC states that it is important to acknowledge that natural gas generation will play a vital role in ensuring a secure, reliable, and evolving lower-emissions grid.

Several commenters discuss the importance of understanding the cost of investments relative to the benefits to the system or to consumers. NJBPU recommends that DOE focus on identifying transmission investments that adequately consider reliability and economic benefits while also facilitating clean energy deployment. NJBPU suggests scenarios should focus on cost-effective solutions that do not rely solely on aggressive policy assumptions. NJBPU believes developing long-distance, high-voltage transmission infrastructure is vital for affordable electricity and reliable clean energy deployment, but consensus requires consideration and quantification of non-clean-energy benefits.

SERTP Sponsors state the Study overlooks transmission costs and siting impacts, which undermines the determination of the true value of transmission needs. Similarly, ERCOT claims the Study does not adequately consider the significant costs associated with the identified transmission additions when analyzing the economic benefit. ERCOT indicates the Study identifies considerable economic benefits for several new transmission facilities across the country, including those connecting Texas to the western U.S. and the Plains region, but fails to address the costs that are likely to be substantial. ERCOT suggests that DOE conduct a more comprehensive cost-benefit analysis so that the net benefit of such transmission facilities can be fully understood. Without such an analysis, the Study does not demonstrate an independent economic need exists to support the construction of expansive and costly new interregional transmission lines. ERCOT suggests that any analysis of improvements should consider the costs associated with constructing all the necessary facilities, rather than focusing solely on a few select projects the Needs Study identifies as having the highest value. ERCOT urges DOE to consider other costs associated with the proposed changes to the power grid, including:

- Additional upgrades to the transmission system to ensure sufficient grid strength and inertia.
- Changes in the costs of managing the dispatch of electricity due to the retirement of older or less efficient power generation caused by increased transfer capability.

- The impact of increased transfer capability on regional dispatch costs due to the intermittent nature of renewable energy sources.
- Adjustments to the requirements for maintaining operating reserves due to increased reliance on intermittent renewable resources.
- Potential modifications to existing market structures and Texas state regulations to effectively handle interregional transfers.

Additionally, ERCOT warns increasing transfer capability between regions can reduce total reserves available to all regions as increased competition from other regions could lead some generators to retire.

ERCOT states that while DOE responds to ERCOT's comment that the Study does not replace the responsibilities of regional entities when it comes to transmission reliability and planning, DOE does not directly address its concern that the Needs Study does not consider costs associated with transmission additions.

Con Edison and AE discuss cost allocation methods. Con Edison emphasizes the importance of fair cost allocation methods that consider the benefits of interregional connections during power system emergencies. AE refers to a recent FERC technical conference that discussed minimum interregional transfer capability. AE notes that experts at the conference raised important concerns like cost allocation, alternatives to transmission infrastructure and assessing the benefits of meeting interregional transfer requirements relative to the investment costs. AE also suggests cost allocation projects should be based on a beneficiary pays approach wherein the beneficiaries of improving the ability to transfer energy will need to be identified and considered as this topic evolves.

National Grid recommends DOE incorporate more detailed regional cost modeling, which would better quantify the operational cost benefits of an interregional connection between New York and New England and provide more insight into how interregional transmission can reduce price volatility and improve generation dispatch efficiency.

Econwerks claims the Study overlooks the natural monopoly and cost complexities in the electric industry. Econwerks states that using the findings from individual RTO transmission expansion plans that are specific to a particular region to determine transmission needs at the national level is not an optimal method of assessing transmission needs.

SERTP Sponsors claim the Study underestimates the transmission needed as the zonal modeling results assessed in the Study do not adequately address impacts on lower voltage systems. It states that proper evaluation of transmission costs is necessary and that economic evaluations that incorporate transmission costs are essential when designating NIETCs. It also states that collaboration with registered planners and coordinators is crucial to incorporating these evaluations into the Study.

AE notes the Study frequently references MISO's *Renewable Integration Impact Assessment*. AE states the RIIA helps identify system issues that could arise with increased renewable energy penetration, but the Study does not show how to address these issues or focus on implementation steps that would likely be taken as more renewables are brought online. According to AE, MISO did not find any milestones of the system becoming inoperable up to the 50% penetration levels studied; however, AE believes there is still much to learn about effectively integrating higher levels of renewable energy. AE suggests the RIIA results indicate the need for further analysis to truly understand the optimal integration of renewable energy resources.

Gallatin Power recommends further research focusing on the WECC Paths to evaluate significant transmission constraints in the western region.

AEP recommends DOE should acknowledge the importance of local transmission planning in alleviating capacity constraints and congestion. AEP notes that there is significant overlap between reliability violations and economic congestion. AE notes that addressing reliability issues through local or regional reliability projects can proactively address economic congestion.

ERCOT values DOE's recognition that Texas has built more transmission infrastructure than have other regions. However, ERCOT disputes the accuracy of DOE's statement that transmission investment and construction from 2016 to 2020 has experienced a "sharp decline" in ERCOT. ERCOT notes it has seen substantial investments between 2013 and 2016 via the Competitive Renewable Energy Zone (CREZ) initiative led by the PUCT. ERCOT provided a figure in its comment illustrating the consistent increase in transmission improvements over the past decade.

DCC proposes adding a new section or subsection to *Section V: Review of Existing Studies: Current and Future Needs*, detailing information about the Study's overall process and methodology, particularly as it relates to the inclusion of source data and reports. DCC sees the benefit from discussing potential issues and limitations when relying on data from past or regional reports. Similarly, PIOs recommends that DOE acknowledges the limitations of studies and reports chosen for inclusion in the literature review portion in the Needs Study for two purposes. First, PIOs recognize the possibility that identified needs may be more urgent than initially suggested in a study or report included in the literature review portion of the Needs Study. Second, they state that absence of transmission needs in less comprehensive studies does not imply the absence of further needs endorsed by DOE. PIOs also recommend DOE clarifies its own criteria for assessing whether a present or future transmission need exists. PIOs state several studies and FERC's recent regional transmission Notice of Proposed Rulemaking have emphasized the importance of evaluating transmission needs under multiple anticipated scenarios, which includes considering factors such as expected changes in generation, shifting demand trends, and extreme weather patterns. Therefore, PIOs state it is crucial to assess all potential benefits of proposed solutions rather than focusing on limited types.

CEBA similarly suggests DOE provide more explanation on why DOE chose to conduct the Study through a review of existing literature. CEBA proposes adding a new section after *Section II: Legislative Language* to thoroughly explain the Study's overall method, including its limitations, rationale for the literature review, differences from the NTP Study, and the possibility of under-projecting transmission needs.

Scenarios

Some commenters shared their thoughts and suggestions on the capacity expansion scenarios used in the Study.

CEBA supports the Study's findings and the approach of grouping Capacity Expansion Modeling study results; it recommends, however, that GDO provides further reasoning on the Study's methods. CEBA highlights the importance of considering large energy customer load and growth often overlooked in transmission planning studies to avoid underestimating clean energy demand and load growth.

ACORE recommends that DOE use the High/High scenario in the final Study as the base case to most accurately reflect the drivers of transmission needs, including IIJA and IRA, and the increasing electrification of buildings and transportation. AMP also proposes the Needs Study should use a scenario with high load and high clean energy assumptions (High/High) as its base case, given passage of the IRA and given EPA's proposed ruling for reducing harmful emissions.[40] The WATT Coalition also believes that the High/High scenario should be used to determine future needs due to the passage of IIJA and IRA best represents the High/High scenarios and recommends placing greater emphasis on higher renewable energy growth assumptions.

Martyn Roetter points out that the Study's discussed scenarios, projecting future grid loads of 7,000 terawatt-hours (TWh) to 8,000 TWh by the 2040s, fail to consider the significant demand for clean electricity to produce green hydrogen or carbon dioxide removal systems. The focus of the Study appears to be on the increased grid load driven by the electrification of transportation and buildings.

NJBPU highlights that the Moderate/High scenarios may include policy assumptions that require high levels of clean energy integration. Consequently, the transmission solutions identified using these scenarios may not correspond to transmission investment needed to maintain reliability in a cost-effective manner. NJBPU suggests incorporating scenarios that prioritize "no regrets" transmission solutions, which can reduce costs and support clean energy deployment without compromising reliability.

Results and Findings

Some commenters disagree with some of the findings of the Study, while others seek additional clarification.

North Carolina Utilities Commission (NCUC) disagrees with the Study's claim that current utility plans in the Southeast fail to meet the needs identified in the Study, explaining that public

[40] U.S. Environmental Protection Agency. 2023. Proposed Rule: Multi-Pollutant Emissions Standards for Model Years 2027 and Later Light-Duty and Medium-Duty Vehicles. Available at https://www.epa.gov/regulations-emissions-vehicles-and-engines/proposed-rule-multi-pollutant-emissions-standards-model.

utilities in North Carolina are involved in long-term transmission planning processes, as required by federal regulations and state law. NCUC emphasizes that studies considered in the DOE draft Study are separate from the ongoing work specific to North Carolina's electric system. Therefore, the results may differ from what is happening in North Carolina. NCUC suggests DOE exclude North Carolina from the statement regarding the utilities in the Southeast lacking sufficient plans to meet anticipated 2035 needs or provide more information to explain the basis for the statement.

SERTP Sponsors also disagree with the Study's claims that the Southeast will need a lot more transmission capacity in the future, as it does not have enough evidence to support this assertion. SERTP Sponsors claim that the Southeast already has a strong transmission system and has been investing in it to meet the needs of customers and to accommodate state energy policies. SERTP Sponsors mention that the Southeast has achieved lower electricity costs, high reliability, and successful implementation of state resource decisions. It notes the Study overlooks some unique characteristics of the Southeast, such as existing long-distance transmission lines and the focus on providing physical transmission so that long-term firm commitments can be served with the intent of no congestion or curtailment. It argues DOE's analysis of transmission investment from 2011 to 2020 is limited and does not reflect current increased investment.

AE indicates that the Study lacks sufficient context for transmission investment decisions, stating that the Study does not pay enough attention to optimizing the overall system or discuss how customers will be affected by transmission spending. AE does not think the Study provides practical guidance on expanding the transmission system in a cost-effective manner. AE adds that it is important to understand the policies and business incentives that have led to the current needs. ACP notes that DOE should highlight the gap between the increasing pace of the energy transition and lack of investment and implementation of interregional transmission. ACP suggests mechanisms like siting assistance, loans, and capacity contracts to bridge the gap between the energy transition and the lack of interregional transmission investment.

In response to DOE's finding that 50% or more of an asset's value can be realized in the worst 5% of hours, Xcel Energy suggest further investigation into the reasons behind the 5% of hours that drive these benefits and the likelihood of encountering those system conditions throughout the lifespan of new transmission assets. Xcel Energy questions how the authors of the Study perceive the risk and value of assets. It says addressing these risks will likely involve considering a broader range of options beyond just expanding transmission.

Xcel Energy also comments on the regional results, as summarized below:

- **Mountain.** The Study draws conclusions about the ability to transfer power between Colorado and the rest of the Western Interconnection. However, the Study also suggests that the eastern parts of the Western Interconnection would benefit from better transfer capability with areas further east. Further analysis is needed to compare the value of improving connections eastward or westward in the eastern part of the Western Interconnection. Comparatively simple solutions, such as changing contractual pathways and adopting new approaches to facility ratings, could provide significant benefits without incurring additional transmission costs. Any transmission development beyond policy-based mitigation would then be a more optimal solution. The potential value of connecting the Southwest region with the Texas region is considered. Xcel wonders if similar benefits would be achieved by improving connections between the mountain and Texas regions, allowing for greater power transfers between the West and southern SPP or ERCOT.

- **Southwest.** The Study results indicate that the transfer capacity between the Southwest and Texas needs to be increased for improved reliability and resilience. Southwestern Public Service, an operating company of Xcel Energy, serves the area between these two regions in the Plains region. Depending on how the transfer capability is increased, there may be unintended consequences in the Plains area that would need to be addressed in project development planning. Considering the recent events impacting the system in this area, it raises the question of whether a transmission solution is the right approach or if additional investment in cold weather protection would be more cost-effective.
- **Plains.** Xcel Energy believes that the Plains/SPP region has been understudied compared with other regions. Most of the recommendations provided are generic, which makes it challenging to rely solely on the Study for a way forward. The Study's conclusion that average prices in the region have been increasing compared with neighboring regions lacks substantial support and could be addressed in various ways, not just through interregional transmission as suggested by the Study. A more detailed analysis of the factors influencing locational marginal price trends would be valuable in determining the appropriate solution for addressing such changes.
- A couple of commenters describe the advantages of co-locating transmission lines on transportation or other utility corridors. FAS supports the Study’s suggestion that co-locating new transmission lines with existing rail, highway, or pipeline infrastructure can be a promising solution to bypassing development challenges. FAS states that it involves negotiating with fewer stakeholders and takes advantage of the proximity to areas with renewable energy potential and avoids disturbing undeveloped land. FAS adds that it can reduce the time and effort required for acquiring leases, increase investor confidence, and speed up the deployment of new transmission infrastructure. FAS suggests DOE’s RAPID toolkit can be a valuable resource, although it currently lacks information specific to building transmission lines in railroad rights-of-way. Both FAS and Keryn Newman highlight the SOO Green HVDC [high-voltage direct current] Link project[41] as a potential example for rail co-location with HVDC transmission and note the benefits of burying transmission lines alongside highways and railways. FAS suggests that incorporating co-location into regulatory information resources would greatly benefit future transmission developers.
- PIOs state that although it is beneficial to have connectivity between MISO North, SPP, and MISO South, it is also important for the Study to acknowledge the advantages of increasing direct transfers between MISO North (Midwest) and MISO South (Delta). Additionally, PIOs note that while the Study should prioritize interregional projects that

[41] Available at https://soogreen.com/.

are more challenging to implement, it should not overlook regions that have struggled to build transmission infrastructure within their own market boundaries. The difficulties in developing within MISO South and connecting MISO North and MISO South are examples of significant transmission needs that have national importance and should not be disregarded.

- Con Edison emphasizes transmission expansion efforts in New York should not be dampened by the Study's conclusion that New York's planned transmission exceeds DOE's anticipated needs for both scenarios. Con Edison encourages continuous efforts to expand transmission infrastructure, including at the local level.
- ERCOT believes achieving the economic, reliability, and resiliency benefits outlined in the Study for Texas cannot be accomplished by selectively implementing projects that are deemed to provide the highest value. ERCOT suggests that any analysis of improvements should consider the costs associated with constructing all the necessary facilities, rather than focusing solely on a few select projects with the highest value.

Interregional Capability Analysis

- Several commenters discussed the factors that should be considered in the assessment of interregional investments.
- PJM raises concerns about the lack of clear criteria or metrics in the Needs Study to gauge the level of transfer capability needs. PJM believes that ongoing work at FERC and the EIPC should be considered to develop appropriate metrics and defers to the ongoing Interregional Transfer Capability Proceeding to establish metrics and methodology.
- Dana Siler expresses concern about the Study's lack of emphasis on connecting the central region of the country to PJM. Siler highlights the testimony of PJM's Vice President, Asim Haque,[42] who raised alarm about PJM's ability to provide reliable electricity in the medium term due to new state decarbonization policies. These policies could lead to the retirement of thermal resources and an increase in the share of renewable energy in PJM's resource mix, potentially affecting its reliability. Connecting PJM to the central region could offer a more reliable solution, reducing the need for aging coal plants and avoiding stranded natural gas assets.

ACORE also points out that DOE uses different measures to quantify interregional ("the amount of power that new or upgraded lines can move between neighboring regions, regardless of the length of the lines that make that connection across boundaries") versus regional (GW-mi or TW-mi) transmission needs and plans and suggest that DOE elaborate on the relationship between its interregional and regional analyses.

EEI states that determining interregional transfer capacity involves complex and technical analysis and that conversations across industry continue to evolve. According to EEI, the Study

[42] Available at https://ohiochannel.org/video/ohio-senate-energy-and-public-utilities-committee-2-28-2023 and https://search-prod.lis.state.oh.us/cm_pub_api/api/unwrap/chamber/135th_ga/ready_for_publication/committee_docs/cmte_s_energy_pu_1/submissions/cmte_s_energy_pu_1_2023-02-28-1000_137/asimhaquepjm.pdf.

does not appear to consider important factors highlighted at FERC's workshop on interregional transfer capability, including:

- The need for a clear definition of transfer capability.
- Other factors beyond direct connection that can affect the transfers, as determining transfer capability between regions is not as simple as adding up the capacities of power lines between them.
- Any facility planned to facilitate interregional transfers must have clarity and consensus on benefits to ensure appropriate cost allocation and enable the construction through state regulatory processes.
- Significant levels of new transfer capability between regions would likely require upgrading the existing transmission system in the receiving region.

AMPUA and IEDA highlight the limited import and export capabilities of the Southwest region and urge DOE to emphasize the importance of increasing transfer capacity between ERCOT and the Eastern and Western Interconnections.

NJBPU recommends the Study focus on identifying transmission projects that can deliver net benefits from a reliability and economic perspective that also facilitate the energy transition and where they should be constructed. NJBPU adds that when combined with detailed data on candidate transmission projects from the upcoming NTP Study, this could demonstrate the wide-ranging benefits of investing in major infrastructure projects to all stakeholders and help build consensus on the need to develop and fund significant regional and interregional transmission infrastructure.

National Grid emphasizes the significance of interregional transmission in facilitating clean energy growth and economic security, particularly in regions like the Northeast. National Grid believes that valuable insights can be shared with other regions through the Study. In addition, National Grid explains that it can assist DOE in expanding the Study analysis by including operational and resource modeling across regions and evaluating interface impacts on resilience and reliability.

SREA discusses the impact of four major winter events in the past 11 years—the 2014 Polar Vortex, 2018 Cold Weather Bulk Electric System Event, 2021 Winter Storm Uri, and 2022 Winter Storm Elliott—to show that interregional transfer capability between the Southeast and MISO regions is necessary and would provide value.

SPIGs say Winter Storm Elliott revealed serious transmission network problems in the Southeast, which should be considered in identifying the region's interregional transmission needs. SPIGs add the storm revealed that while the Southeast experienced blackouts, the central region had excess wind energy that could not be used due to inadequate infrastructure. SPIGs suggest DOE stress the urgency to prevent future disasters and improve the Southeast's interregional transmission.

Hydro-Québec recommends that DOE provide additional information on the importance of international transmission investments in enabling two-way trade of electricity. It states that by facilitating greater two-way trading of electricity between Québec and the United States, the benefits of each region can be shared more broadly, promoting renewable development and ensuring a stable supply of clean energy. Hydro-Québec cites studies showing that bidirectional transmission between Québec and the Northeast is crucial for achieving ambitious state climate policies and reducing power system costs. It adds that expanding the clean energy partnership between the Northeast and Québec will require additional HVDC lines, providing numerous additional benefits to the system.

Department Response

In response to comments related to resource adequacy, the Department added eight industry studies that discuss resource adequacy to *Section V.a. Reliability and Resilience* (pages 59–62) of the final Study. The Department is clear that resource adequacy requirements can be met through a mix of solutions, including, but not limited to, interregional transmission: "Regions meet their resource adequacy requirements through a mix of regional generation, demand response, and firm capacity transfers across intra- and interregional transmission lines" (page 59).

Cost allocation methodologies or analysis are considered out of scope for this assessment of physical need of the transmission system. Supply chain concerns, though capable of having a major impact on the development of new transmission capacity, are also deemed out of scope.

Historic non-incumbent developer transmission investments are discussed on pages 25–27 of *Section IV.a. Historic Transmission Investments*, including the addition of Figures IV-4 and IV-5, which show a comparison of developer investments at the regional and voltage class level.

The final Study highlights that a diverse generation mix is necessary to reliably meet the evolving needs of the power sector, as is stated on page vi of the Executive Summary of the final Study: "Study findings also indicate that interregional and cross-interconnection transmission investments will improve system resilience and alleviate resource adequacy concerns by enabling increased access to diverse generation resources across different climatic zones." Furthermore, many different technologies are considered "clean" for the purposes of grouping scenarios in *Section VI. Anticipated Future Need Assessment through Capacity Expansion Modeling*: "The annual percentage of clean energy generation, including all solar energy technologies (concentrating solar power, utility-scale photovoltaic systems, rooftop photovoltaic systems), land-based and offshore wind power, hydropower, nuclear energy, hydrogen-based technologies, biomass energy, coal and natural gas plants paired with carbon capture and sequestration technologies, and landfill gas plants were considered" (page 116). See Department Response in Section 4.4 of this comment synthesis for a discussion of how increased demand due to hydrogen production and carbon dioxide removal is considered in Section VI.

Several commenters requested more insight into how the Department determined criteria for identifying transmission needs. As part of the Department's approach to summarizing transmission needs discussed in the Study, the Department created finding summary graphics in the Executive Summary (Figure ES-7, page xi), Section IV (Figure IV-18, page 50), Section V (Figure V-17, page 109), and Section VI (Figure VI-12, page 142). The Supplemental Material provides a detailed discussion of the methodology used to categorize information included in the Study as a transmission need.

The MISO *Renewable Integration Impact Assessment* is one of many studies included in Section V, notably pages 54–55 of *Section V.a. Reliability and Resilience*, which discuss the complexities of connecting large penetrations of variable energy resources to the larger transmission system. Findings from this study are appropriately incorporated into the Study.

Commenters also requested more nuanced discussion of the role of local transmission planning for alleviating capacity constraints and congestion. The Department has provided more context in *Section I.a. How to Use This Study* to identify how Study findings can inform existing transmission planning processes. Additionally, see the Department Response in Section 1.6 of this comment synthesis for a response to how interregional transmission investments can have impacts on the local and regional systems.

The Department appreciates ERCOT sharing their data on transmission investments by in-service year. The Department believes the trends of investment shared by ERCOT match that published in the final Needs Study. The Department added information on the CREZ investments and how those impacted the regional investment trends in the final Study in *Section IV.a. Historical Transmission Investments* by adding Figure IV-7 and subsequent discussion (pages 29–31).

In response to commenters requesting an increased focus on high load growth, see Sections 2.1 and 2.3 of this comment synthesis above in which the Department includes additional context regarding the relevance of the high load and high clean energy capacity expansion scenario group in the final Study.

In response to entities who commented that regional need in the Southeast has not been appropriately attributed, the Department has added several references and context to additional studies relevant to the region in Section V of the final Study (pages 58, 62, 69, 78, 79 and 80 in particular). These include both utility studies (e.g., Duke Energy and TVA) and state utility commission regulations. Additionally, the Department made a note in the final Study that acknowledges that the Southeast made large transmission investments prior to the years considered in *Section IV.a. Historical Transmission Investments* (page 21).

With respect to comments that the Plains and Mid-Atlantic regions were underrepresented in the draft Study, the Department added approximately four additional studies and additional discussion on transmission needs in the Plains throughout the final Study (pages 39–40, 59–60, and 80 in particular). Please see the Department Response in Section 2.3 of this comment synthesis above discussing the incorporation of additional references and context in the Mid-Atlantic region.

Several commenters suggested additional discussion of the advantages of co-locating transmission lines in transportation or other utility corridors. In response, the Department has added brand new analysis in *Section V.e. Siting and Land Use Considerations* to discuss the possibility of co-locating transmission in interstate corridors (pages 96–103). This subsection includes recent NREL analysis and a discussion about the feasibility of siting undergrounded transmission lines along highways given a variety of unique characteristics. The data sources and methodology used to conduct this analysis is included in pages 26–33 of the accompanying Supplemental Material.

In response to comments requesting more discussion of transfer limitations between MISO North (Midwest) and MISO South (Delta), the Department refers the reader to the Department Response in Section 1.6 of this comment synthesis above, which discusses new references added to Section V.a. that further discuss the Regional Directional Transfer Limit between the Midwest and Delta regions and associated transmission limitations.

The units for transmission deployment (TW-mi) and transfer capacity (GW) in Section VI are the commonly used units by capacity expansion models. While these differ from one another and from industry-standard units, the Department continues to use them as they were the units used in the underlying studies. The Department does discuss the use of these units and offers examples for how they can be compared with industry units in *Section V.c. Within-Region Transmission Deployment* (pages 121–122).

Certain commenters encouraged the Department to consider the current planning assessments and clarify how these plans align with the analyzed scenarios. In response, the Department added *Section VI.e. Comparison with Utility Plans* (pages 139–141) to discuss further how current utility plans for additional transmission development compare with anticipated future need revealed in the capacity expansion models considered in the Study. Table VI-5 (page 139) lists seven industry references, in addition to two industry references included in the draft Study, which were added to the final Study to make this comparison.

In response to commenters highlighting how recent extreme weather events have shown a need for additional interregional transfer capacity, the Department has made several changes to the final Study to incorporate this need. See pages 39–42 of *Section IV.b. Market Price Differentials* and pages 58–59 of *Section V.a. Reliability and Resilience* in particular. Additionally, see the Department Response in Section 2.2 of this comment synthesis above for a discussion of references added related to extreme events.

In response to commenters who believe not enough transmission need is identified in the northeastern regions (New York and New England), including international transfers, the Department made numerous changes to the final Study. The Department acknowledges that the moderate load and high load growth scenarios highlighted in the draft Study did not fully capture the high load growth policies established in these and other regions. For this reason, the Department has additionally highlighted the high growth capacity expansion scenario results throughout the report. See the above discussion on where these changes were made.

Specific to findings of low international transfers, the Department has moved the findings of international transfer capacity from the draft Study to the Supplemental Material. Upon internal review and additional discussions with commenters, the Department believes that the scenarios that fed these results were low in number and did not adequately capture future power system changes. A discussion of the results can be found in the final Study on pages 74–77, 89, 130–131. The Department also supplemented the discussion about international transfers with Canada in *Section V.c. Generation and Demand Changes* on pages 76–80 referencing three other studies.

The Needs Study is an assessment of previously published work and does not include any new modeling. This synopsis incorporates demand forecasts into new capacity expansion modeling, cost-benefit analyses of individual or portfolios of projects, assessments of value of individual or portfolios of projects, and new scenario development for capacity expansion modeling. While many of the analyses requested by commenters are important to transmission system planning, all comments suggesting new modeling methods are considered out of scope. As pointed out by several commenters, some of these requested modeling exercises are being performed in separate Department studies, such as the NTP Study. The Department did add *Section I.a. How to Use This Needs Study* (pages 2–4), which briefly discusses how the findings of the final Study can be incorporated into other planning processes.

While additional project cost analyses are out of scope, the Department does report system costs for several national capacity expansion modeling studies throughout Section V, most notably in Figure V-6 (page 75). Additionally, all transmission expansion results presented in *Section VI. Anticipated Future Need Assessment through Capacity Expansion Modeling* are the result of least-cost optimization modeling, meaning that these transmission solutions were found to be cost-optimal when compared with a suite of other supply- and demand-side solutions under a set of modeling assumptions. While not as resolved as a financial cost-benefit analysis of individual or portfolios of specific projects, least-cost optimization does provide a general sense of the amount of transmission expansion that would be economically viable given a particular set of scenarios.

2.5. Other Gaps

Approximately seven commenters provide additional comments highlighting gaps in the Study that DOE should consider.

National Grid, the Blue Lake Rancheria Tribe, ACC, and SPIGs offer insights and challenges specific to their regions or sectors:

- National Grid emphasizes the importance of interregional transmission in the Northeast, particularly during winters, highlighting gas supply constraints and price increases due to reliance on imported liquid natural gas. National Grid also anticipates both Upstate New York and New England to interconnect large amounts of renewable energy in the next decade.
- In reference to Section V.c.2., the Blue Lake Rancheria Tribe notes that while many Tribal nations are actively seeking to build electrical infrastructure, inadequate transmission capacity is slowing adoption of electrified transportation, building electrification, and development of DERs in Tribal lands. The tribe highlights the negative impact of transmission limitations on Tribal nations' economies, leading to a reliance on high-emission fossil fuel generators.
- ACC stresses the need for lower-emissions energy sources in energy-intensive manufacturing sectors like the U.S. chemical industry. It states the importance coordination between DOE, FERC, and states in building national transmission aligned with the most ambitious scenario for transmission investment, urging policymakers at all levels to understand the requirements to meet ambitious projections.

- A lack of transparent market pricing and regional transmission planning leads SPIGs to urge DOE to consider existing needs in the Southeast that may be incapable of quantification, such as those found in utility statements or official regulatory processes. They cite TVA as an example as TVA chose gas power over solar and storage options because of the perceived high expense of transmission costs, despite experts highlighting the benefits of renewable sources for reliability and resilience.

NYTOs suggest DOE incorporate the latest transmission projects that have been included in NYISO's transmission planning to avoid significant omissions that would change the draft Study's conclusions:

- The AC Transmission Project
- The Smart Path Connect Project
- The Tier 4 HVDC Projects (CHPE and Clean Path New York [CPNY])
- The Long Island Offshore Wind Export Public Policy Transmission Need (PPTN) Projects

NYTOs argue that DOE should consider the significant impact of the Long Island PPTN project. If timing poses challenges, they recommend incorporating it in future assessments that could lead to the designation of NIETCs. NYTOs highlight that these transmission projects would effectively address concerns raised in the Study, such as price disparities between upstate New York and Long Island and historical high prices observed on Long Island.

National Grid further points out that national leaders could gain valuable insights from New York's experiences and lessons learned in policy and process development, particularly in the integration of renewable energy. National Grid mentions the 2020 Accelerated Renewable Energy Growth and Community Benefit Act, which has already attracted over $5 billion in investments for local transmission infrastructure to support renewable energy delivery throughout the state. National Grid also discusses major bulk transmission projects, such as Smart Path Connect, CHPE, and CPNY, as well as New York utilities' Coordinated Grid Planning Process aimed at achieving the state's clean energy goals. Lastly, National Grid mentions the PPTN process, which seeks competitive transmission solutions to accommodate renewable energy generation.

Department Response

The Department thanks commenters for their comments regarding other gaps.

The Department has included a discussion about natural gas constraints during winter months in the Northeast on page 87 of the final Study. See the Department Response to Sections 2.2 of this comment synthesis above for resolution on including Tribal energy needs into the final Study. See the Department Response to Sections 2.3 and 2.4 above for a discussion on capturing high load growth scenarios in alignment with regional policies and high-demand industries. Additionally, see the Department Response to Section 2.4 above for a discussion on references added that address southeastern transmission need.

The Department emphasizes that the Needs Study is not meant to identify particular solutions in *Section I. Introduction*. As such, the Department made a general practice of not identifying specific transmission projects in the final Study, and therefore projects referenced by commenters are not included in the final Study.

3. Transmission Planning and Security

3.1. Planning and Coordination

Approximately 28 commenters mention topics related to transmission planning and coordination.

Several commenters strongly agree with DOE's conclusions in the Needs Study that there is a need to expand interregional and cross-interconnection transmission planning to improve reliability, support electrification efforts, support the clean energy transition, and reduce customer costs. ACORE indicates that the Study could identify transmission planning processes as a transmission need, thereby expanding the Study scope to determine what gaps and opportunities could improve regional and interregional transmission planning processes.

Several commenters remark on the failure of current regional and interregional transmission planning processes and stress the importance of improving them. For example, AEU and PIOs argue that current transmission planning processes across the country result in "inefficient investments that foreclose meaningful competition, miss out on economies of scale, and result in consumers paying considerably more for significantly less—less choice, less capacity, less flexibility, less resiliency, and ultimately less reliability." AEU, AEP, PSEG, and PIOs advocate for the use of multi-value and scenario-based approaches to planning, which enhance the processes' ability to determine more cost-effective investments (providing energy price benefits to consumers), address uncertainties, and reduce system-wide costs and risks. Similarly, National Grid recognizes that future investments need to take into consideration a holistic view of the diverse needs of customers and system at large such as reducing transmission curtailments, bolstering grid resiliency, enabling a clean fuel mix, and access to low-cost resources. AEU notes that eliminating existing barriers to regional and interregional transmission projects can maximize net consumer benefits across regions and improve reliability and resilience in the face of increasing extreme weather events. PJM requests that DOE assess how resilience considerations in intermediate- and long-term regional planning processes affect the determination of transmission needs and corridor designation.

Similarly, AE notes that transmission planning processes need to be more dynamic and flexible to respond to evolving needs and solutions. AE notes the need for transparent, robust planning processes with meaningful stakeholder engagement and consideration, wherein projects with long lead times are reviewed every 3 years to ensure that initial project planning assumptions remain accurate. AE and other commenters indicate that transmission planning processes must modernize to ensure that diverse solutions and advancements are properly considered.

While AE expresses its appreciation for DOE acknowledging that the intention of the Needs Study is not to replace current planning processes performed by regional planning entities, it believes that the Study could benefit from identifying current reforms across regulatory levels that might address needs identified in the Study. For example, several commenters, including AE, NJBPU, ITC, and ACORE reference MISO's LRTP, a planning effort consisting of multiple tranches of projects focused on various areas and needs of the MISO footprint. AE also references the MISO and SPP JTIQ Study, which is helping to address the need for increased transfer limits between the Midwest and Plains regions. ITC urges DOE to be attentive of the benefits of incumbent utilities being allowed a right of first refusal (ROFR), as witnessed in the successful approval of the LRTP Tranche 1 portfolio and ongoing development of Tranche 2.

AEP describes its interregional planning, minimum transfer proposal in detail, and suggests an Interregional Reliability Planning Assessment (IRPA) be conducted to determine the appropriate minimum interregional transfer capability necessary for regions to cost-effectively support reliable system operation.

SPIGs illustrate the pressing transmission needs in the Southeast, despite limited data on the region, and suggests that DOE consider them in the Needs Study. SPIGs detail that throughout the Southeast, utilities do not proactively plan for necessary transmission expansion. SPIGs emphasize that the Southeast's dire need for transparent market pricing and regional transmission planning require creative solutions to expose regional needs. For instance, SPIGs explain that SERTP Sponsors' regional transmission plan has not once included a regional transmission facility, primarily due to its narrow regional evaluation process. SPIGs explain that local plans, which lay the groundwork for the regional plan, typically only consider reliability needs, and rarely conduct multi-value planning, which limits the benefits that inform the analysis. And when a regional project is considered, SPIGs describe how, as expected, larger regional project costs are far greater than small local project costs, resulting in none of the regional projects being selected. Given all these challenges, SPIGs argue that the prospects for transmission development in the Southeast are "slim under the current planning paradigm," and therefore Southeast planning processes will provide minimal assistance in DOE's effort to identify transmission needs.

Other recommendations by commenters include AEP suggesting that DOE recognize that local transmission planning is important in alleviating capacity constraints and congestion and in securing a reliable and resilient transmission system. DCC recommends that DOE add a section on best practices for integrating its findings into regulatory proceedings or planning processes.

Lastly, NEMA advocates strongly for siting authorities on the federal, state, and local levels to encourage the use of existing rights-of-ways along railroads, highways, brownfields, and other corridors for transmission development.

Barriers to Transmission Planning and Development

Several commenters also discuss barriers to transmission planning and development. AEU and others agree with the many challenges to siting high-voltage lines summarized in the Needs Study. Commenters elaborate that challenges to planned interregional transmission include aligning stakeholders across regions with divergent priorities, processes, and benefit analyses; arranged planning processes that lead to prioritizing local; cost allocation; and siting and permitting hurdles. Furthermore, AEU observes that barriers to interregional planning make it challenging to optimize net consumer benefits and create investment gaps near and across market seams because regional planning authorities largely focus on local and regional investments and generator interconnection requests. AEU elaborates that the lack of dedicated siting authorities, staff, expertise, and funding, as well as a wealth of "'veto points' where any single siting process can result in a project's rejection," all provide major barriers to transmission approval. The Utah Public Lands Coordinating Office sees the biggest hurdle impeding national transmission needs as National Environmental Policy Act (NEPA), given its expansive and lengthy environmental reviews.

As mentioned above, ITC argues that the most pressing issue hindering transmission development is uncertainty driven by the removal of the federal ROFR. ITC goes on to reference recent research supporting the benefits of FERC's ROFR. PSEG agrees, stating that the elimination of ROFR is one reason for the decline in transmission investment across the country.

Hydro-Québec also suggests that DOE should identify that new market mechanisms and commercial models are needed for efficient transmission development, as financing "will require adaptable funding mechanisms which reflect more dynamic performance of the resource."

PSEG also highlights the planning barriers that exist in multi-state RTOs with varied state public policies and discusses the significant challenges to transmission planning in specific regions, noting that current PJM/NYISO transmission planning and allocation rules largely limit options available for transmission projects that would strengthen ties between the two regions. For example, PSEG emphasizes that within PJM, there are 13 states with varying state public policies. PSEG elaborates that large RTOs also struggle to properly generate a load forecast that captures anticipated load and future demand across states, as trends evolve rapidly, leading to understated load forecasts. SPIGs detail the specific challenges faced in the Southeast's transmission planning processes, stating that the regional planning processes themselves are a barrier to regional and interregional transmission development. Rather than approach transmission planning top-down, like independent planners in RTO/ISO regions, SPIGs note that the region's transmission planning is carried out by the transmission-owning utilities themselves, whose own financial incentives favor local, rather than regional or interregional investment.

AE discusses considerations around the minimum interregional transfer capability requirement that was the subject of a recent FERC technical conference.[43]

Xcel Energy suggests that DOE include additional discussion on how to utilize existing cost allocation mechanisms, while identifying gaps in those mechanisms to confirm that the costs required to address the Study's identified needs are "just and reasonable."

Interconnection

Several comments relate to the interconnection process and interconnection queues.

[43] Federal Energy Regulatory Commission. 2022. Staff-Led Workshop on Establishing Interregional Transfer Capability Transmission Planning and Cost Allocation Requirements held December 5–6, 2022, Docket No. AD23-3-000. Available at https://www.ferc.gov/news-events/events/staff-led-workshop-establishing-interregional-transfer-capability-transmission.

Many commenters note their support for DOE in identifying growing interconnection queue delays as being linked to transmission needs. For example, AES appreciates that DOE includes a section on interconnection queues and describes the relationship between queue delays and the transmission needs. AE asserts that from its experience, interconnection process delays are largely due to affected system issues and projects that drop out of the queue and create the need for re-studies. AE believes that DOE should identify reforms that address specific issues in various regions. AES mentions that DLR could help alleviate interconnection queue delay if transmission planning models incorporate DLR data and insights.

Xcel and Keryn Newman comment on DOE's discussion of generation interconnection queues as a potential indicator of transmission need. Newman states that the Study relies too much on the number of generation projects in interconnection queues as an indicator of transmission need and fails to consider that only a small fraction of projects in the queue is realized. Xcel Energy asserts that queue levels are more dependent on near-term activity, like IRPs and the release of environmental goals, and less aligned with long-term resources shifts.

Econwerks references recent Lawrence Berkeley National Laboratory work estimating that only 14% to 21% of what is in the queue will get built.[44] Econwerks explains that "this is not surprising…when for instance in the MISO footprint the amount of generation in the current queue (1400+ projects totaling 244 GW) far exceeds MISO's 2011 all-time system summer peak demand of 127GW,"[45] which if all installed, "…would take an electrification of transportation even more aggressive than that contained in the draft assessment, a supernormal new inter-RTO dependency, or…an impossible to attain number of new resources. " Econwerks argues that just because policy subsidies encourage developers to undertake the development of generation projects, not all that enter the interconnection queue should be constructed.

ACP claims that the needs identified in the Study will not be realized by relying on generators' willingness to pay for large-scale upgrades. ACP notes that in many regions, regional power networks are being planned and expanded on a piecemeal basis through the project-by-project interconnection process, which leads to inefficient outcomes that ultimately cost consumers. AEG notes that few projects successfully result from the interconnection process, as significant time is required for interconnection review, resulting in many projects ultimately withdrawing applications.

FERC Order 1000

Some commenters mention FERC Order 1000 and its inefficiency in encouraging interregional transmission planning. AEU and PIOs point out that since the Order was issued in 2011, no new

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[44] Wiser R. LinkedIn blog (April 7, 2023). Available at https://www.linkedin.com/posts/ryanwiser_much-of-the-proposed-capacity-in-the-us-interconnection-activity-7049812522169761792-bT9K?utm_source=share&utm_medium=member_desktop. Posting references: Lawrence Berkley National Laboratory. Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection. Available at https://emp.lbl.gov/queues.

[45] Midcontinent Independent System Operator. 2023. Generation Interconnection Queue: Overview. Available at https://www.misoenergy.org/planning/generator-interconnection/GI_Queue/.

major interregional transmission projects have been approved and built[46] and the pace of high-voltage transmission expansion has slowed substantially. AEU elaborates that because local reliability projects are excluded from regional planning processes under Order 1000, the result is a piecemeal approach that has failed to bring about regional transmission build-out, resulted in backlogged interconnection queues, and yielded increased congestion and constraints. PSEG states that Order 1000 works directly counter to the robust, multi-value transmission planning needed, and references an August 2022 study by Concentric Energy Advisors that supports their argument.

PIOs state that the interregional coordination process under Order No. 1000 is effectively broken and point out that loopholes in the Order have resulted in most projects approved in RTO regions to be left out of the competitive process for rulemaking. Monitoring Analytics also argues that even with the implementation of FERC Order No. 1000, there is still no "transparent, robust and clearly defined mechanism to permit competition to build transmission projects, to ensure that competitors provide a clearly defined and enforceable total project cost cap, or to require that transmission owners obtain least-cost financing through the capital markets."

Furthermore, Monitoring Analytics suggests that PJM's Regional Transmission Expansion Plan (RTEP) rules for competitive transmission expansion be built upon FERC Order No. 1000 to ensure real competition between incumbent transmission providers and nonincumbent transmission providers, improve transparency (specifically addressing issues related to data access and cost impacts), and strengthen the queue management process for nonincumbent transmission investment.

Transmission Coordination

National Grid, Con Edison, NEMA, PSEG, and PIOs agree that there are significant benefits of interregional coordination. PSEG adds that interregional coordination helps ensure grid resilience. Additionally, PIOs recall that researchers Patrick R. Brown and Audun Botterud, from the Massachusetts Institute of Technology, found that "'inter-state coordination and transmission expansion [including across regions and interconnections] reduce the system cost of electricity in a 100% renewable U.S. power system by 46% compared with a state-by-state approach, from 135 $/MWh to 73 $/MWh.'"[47]

PSEG encourages improved coordination and collaboration between RTOs and member companies because member companies may be better equipped to capture trends that would lead to more accurate regional transmission planning. NEMA also encourages DOE to specify paths for improved cooperation among regional grid interconnections, in addition to any permitting or other institutional reforms essential for national transmission development.

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[46] The Brattle Group, Inc. 2021. A Roadmap to Improved Interregional Transmission Planning, p. 3. Available at https://www.brattle.com/wp-content/uploads/2021/11/A-Roadmap-to-Improved-Interregional-Transmission-Planning_V4.pdf.

[47] Brown P, Botterud A. 2021. The Value of Inter-Regional Coordination and Transmission in Decarbonizing the US Electricity System, p. 115. Available at https://www.sciencedirect.com/science/article/pii/S2542435120305572.

Other comments suggest that DOE itself coordinate with planning and other entities to better understand regional needs. The NYTOs suggest DOE coordinate with NYISO, PJM, and ISO-NE on further studies projecting the need between New York and the Mid-Atlantic and New England regions before considering any NIETC designation. SERTP Sponsors urge DOE to coordinate with NERC-registered planning coordinators and transmission planners (particularly EIPC). Con Edison suggests that DOE encourage NYISO to work with ISO-NE and PJM to examine the needed interregional transfer requirements.

NEMA believes that increased collaboration and leadership among federal agencies can enable highway rights-of-way to be utilized more quickly, stating that DOE, FERC, the Federal Highway Administration (FHWA), the Department of Interior, and others are key in the development of transmission in rights-of-way.

The Utah Public Lands Coordinating Office notes that building out the transmission required to support growing generation capacity will necessitate coordination with state and local governments. The Office explains that most lines in the western United States are sited on public lands administered by the Bureau of Land Management and the U.S. Forest Service (USFS), and relationships are frequently stretched and tested when direction, policies, and procedures passed down from the federal government change every few years. The Utah Public Lands Coordinating Office elaborates that insufficient coordination between the federal government and state and local governments is a major issue resulting in distrust between governments and energy companies. As a result, Utah requests frequent communication in order to expedite national goals to expand transmission infrastructure and support the anticipated increase in energy production.

Alignment with FERC

A few commenters, including DCC, CEBA, and EEI, want to ensure that DOE's efforts are coordinated with FERC reforms, including those intended to improve transmission planning and generator interconnection processes.[48] DCC believes it is imperative DOE align its activities with FERC's transmission planning, cost allocation, and generator interconnection initiatives. CEBA notes that GDO should ensure NIETC designation activities are complementary to FERC reforms on transmission planning and FERC backstop siting so that transmission planning and siting processes are coordinated and do not delay transmission development further.[49] EEI also remarks that DOE cannot overlook ongoing transmission planning reforms. EEI calls out one statement in the draft Study, that "many existing transmission planning processes 'are primarily focused on compliance with NERC and local reliability standards with very limited scopes and planning horizons,'" claiming that the statement is overly broad and fails to acknowledge FERC's recent proposed reforms to existing transmission planning policy, such as the Notice of

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[48] Utility Dive. 2023. FERC works 'feverishly' on transmission reform, with near-term focus on interconnection rule. Available at https://www.utilitydive.com/news/ferc-transmission-planning-generator-interconnection-reform/645267/.

[49] Federal Energy Regulatory Commission. 2022. Applications for Permits to Site Interstate Electric Transmission Facilities, Notice of Proposed Rulemaking, 181 FERC 61,205. Available at https://www.ferc.gov/media/e-1-rm22-7-000.

Proposed Rulemaking to change existing regional transmission planning and cost allocation requirements.[50]

Department Response

In response to comments requesting an analysis of how past regulations may have impacted historic transmission investments, the Department added a brief description of federal policies and regulations in *Section IV.a. Historic Transmission Investments* on these topics to the final Study (pages 28–29). The Department does not draw any conclusions about the effectiveness of these policies and regulations, however.

The Department received several comments requesting additional information regarding the shortcomings of existing transmission planning processes. The Department reiterates that the Needs Study is not meant to displace existing transmission planning processes nor 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. Consequently, the Department has determined an analysis of existing planning processes is beyond the scope of this Study. However, as noted in the Department Response to Section 1.4 above and in response to commenters requesting a "best practices" section for integrating these Study findings in regulatory proceedings or planning processes, the Department has added *Section I.a. How to Use This Needs Study* (pages 2–4) to the introduction to discuss how entities may use the findings contained in this Study to inform multi-value and scenario-based planning.

Relatedly, several commenters encouraged the Department to discuss pathways for improved coordination and collaboration between regional planners and between states and local governments and federal agencies. In response, the Department provides recommendations for how transmission planning entities might use the findings of the Study to guide coordinated transmission planning and development efforts across systems and regions. *I.a. How to Use This Needs Study* (pages 2–4) also provides recommendations for how states and local governments might incorporate Study findings in their own regulatory and planning processes to guide coordination with other states, regional transmission planning authorities and federal agencies. The Department additionally notes that the Brown and Botterud study referenced by commenters is discussed at length in the final Study.

Additionally, commenters suggested the Department identify current planning efforts and reforms that might address needs identified in the Study. In response, the Department highlights transmission planning processes, such as the MISO Multi-Value Project Portfolio and Long-Term Regional Transmission Plan, which have resulted in transmission project portfolios capable of addressing multiple need drivers (page 31). The Department does not, however, hypothesize how reforms to various state or federal regulations—including those of FERC—could impact future investments.

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[50] Federal Energy Regulatory Commission. 2022. Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection, Docket No. RM21-17-000, 179 FERC 61,028. Available at https://www.ferc.gov/media/rm21-17-000.

The Department agrees that there are many causes for long interconnection queues aside from inadequate access to transmission. This point is appropriately caveated in *Section IV.d. Interconnection Queues* in the passage that begins "There are numerous drivers of these trends. While lack of access to transmission is a major barrier, there are many potential reasons that proposed power plants do not always move rapidly to the construction phase…" (page 48). Certain commenters encourage DOE to consider the use of existing rights-of-way for transmission siting along railroads, highways, brownfields, and other corridors. In response, and as noted in the Department Response in Section 2.4 above, the Department has added new analysis and extensive discussion to *Section V.e. Siting and Land Use Considerations* of the final Study to discuss the possibility of co-locating transmission along highways (pages 96–103).

In response to several commenter requests to elaborate on challenges to planning transmission, particularly interregional transmission, the Department has significantly expanded and restructured Section V.i. in the draft Study to provide a more in-depth discussion of transmission siting and land use considerations, now incorporated into *Section V.e. Siting and Land Use Considerations* of the final Study (pages 95–107). This section includes several additional references to further the discussion on challenges of siting transmission, co-locating transmission along other energy corridors, balancing competing land use interests, and community, stakeholder and Tribal engagement during siting and permitting of transmission.

Several commenters additionally suggested the Department ensure NIETC designation activities are complementary to FERC backstop siting authority. The Department has included additional context in *Section I. Introduction* of the final Study to clarify the Study's relationship with the Department's NIETC designation process (pages 1–2). See the Department Response in Section 1.4 above for additional discussion.

3.2. Physical and Cybersecurity

A few commenters suggest that DOE expand on its discussion of physical or cybersecurity in the Needs Study. PSEG agrees with the Needs Study's assertion that transmission can provide resiliency in extreme weather events; however, it emphasizes the need for resiliency planning to mitigate physical and cyber security threats and urge DOE to include this need in the Study. PSEG explains that "there are significant interdependencies between [transmission] systems" and any attack, "no matter how small or how isolated, can have a far-reaching impact beyond one substation or even one company." PSEG cites recent FERC initiatives[51] and communications, and PJM's Attachment M-4 process,[52] to indicate that there is a consensus among experts and that the grid's physical and cyber security need to be prioritized. PSEG also cites its efforts to engage in resiliency planning at a state level and includes insights, which were

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[51] Federal Energy Regulatory Commission. 2022. Incentives for Advanced Cybersecurity Investment; Cybersecurity Incentives, Notice of Proposed Rulemaking, 180 FERC 61,189, Docket No. RM22-19. Available at https://www.ferc.gov/media/e-1-rm22-19-000. (This NOPR supersedes the Commission's December 2020 Cybersecurity Incentives NOPR. Cybersecurity Incentives, Notice of Proposed Rulemaking, 173 FERC 61,240, Docket No. RM21-3.)

[52] PJM Interconnection. Open Access Transmission Tariff, Attachment M-4. Available at https://agreements.pjm.com/oatt/34859.

emphasized in its recent testimony before the Assembly Telecommunications and Utilities Committee of the New Jersey Legislature.[53] These include: (1) PSEG's efforts to the ensure the physical security of the grid and address critical infrastructure needs, (2) the "continued vitality and increasing importance" of public-private collaboration, (3) the need to invest in the future resiliency and reliability of the grid, and (4) supply chain concerns.

Utah Public Lands Coordinating Office states that increasing interregional transmission capacity could increase or decrease system vulnerabilities. The Office urges DOE to prescribe methods to prevent and combat cybersecurity threats in the Needs Study. Econwerks implies that there are benefits to a fragmented national grid, arguing that system failures can be isolated. Econwerks cites the summer 2003 U.S. blackout, in which the Northeast was able to protect itself from the cascading disturbance in MISO, PJM, and Canada. Econwerks urges the Needs Study to consider the reliability implications of a highly connected national grid.

Keryn Newman argues that undergrounding transmission lines along transportation corridors would improve grid security.

Department Response

The Department thanks commenters for their comments regarding physical and cybersecurity. Except for physical security of the grid as it relates to grid reliability and resilience, the Department has determined that security issues are outside the scope of the Needs Study. This omission is not meant to imply that the Department does not find issues of grid security of vital importance, however. The Department is working on security issues in other programs, notably within the Office of Cybersecurity, Energy Security and Emergency Response, the Grid Modernization Initiative, and the Office of Electricity.

3.3. Environmental

Environmental Impacts

Several commenters suggest that DOE emphasize the many environmental concerns around new transmission.

The Center for Biological Diversity emphasizes the need to minimize negative impacts from utility-scale transmission and generation development. It explains that energy projects are disproportionately sited in environmental justice communities, further burdening populations, and too often sited in environmentally sensitive habitats. The Center for Biological Diversity cites directives in the IIJA, which instruct DOE to facilitate transmission expansion in a way that avoids and minimizes impacts on sensitive environmental areas and cultural heritage sites. To fulfill this mandate, the Center for Biological Diversity encourages DOE to restrict transmission development to areas where NWAs are insufficient to meet needs. Additionally, it encourages DOE to prioritize development in previously degraded lands to minimize impacts on communities, habitats, and species and to, under no circumstance, facilitate the connection of new transmission to fossil fuel power generation. The Center for Biological Diversity explains

[53] New Jersey Assembly Telecommunications and Utilities Committee, March 20, 2023.

that the focus should be on a rapid transition away from all fossil fuel resources and suggest that degraded landscapes like Superfund sites, brownfields, landfills, abandoned mine areas, and contaminated or abandoned agricultural lands are more suitable for large-scale renewable energy projects. The Center concludes that additional renewable energy and necessary transmission should be built with appropriate community input on degraded lands or lands with existing rights-of-way like highway or railway corridors, which would streamline the review process and minimize conflicts, delays, and adverse impacts on the environment.

The Center for Biological Diversity also mentions that the construction of new transmission lines in previously undisturbed areas can negatively affect sensitive ecosystems, including critical habitats for threatened and endangered species. Additionally, construction of new lines can increase air, water, and noise pollution and disrupt commercially or culturally important natural vistas. The Center notes that these impacts sometimes fall on communities that are not the beneficiaries of electricity to be delivered via the new line.

Similarly, the Utah Public Lands Coordinating Office states that it is not unusual for transmission lines to be in or near critical habitats for endangered and threatened species. Therefore, the Utah Public Lands Coordinating Office recommends that transmission lines should be placed in existing disturbed corridors wherever feasible. It states that this has posed significant challenges, especially in Sage-grouse Management Areas. The Office also adds that the current Needs Study fails to sufficiently address the collaboration across state borders to support species planning, habitat improvements, and reducing disturbances.

EDF supports DOE's statement in the draft Study that "[e]xpanded transmission along with storage and other non-wire alternatives could create avenues for frontline communities to have access to community-owned renewable generation projects which could decrease costs, reduce air pollutants that cause adverse health impacts, and advance energy democracy."[54]

Econwerks states that the Needs Study fails to mention that transmission development has externalities that affect land use, the natural environment, farming, and tourism.

The Utah Public Lands Coordinating Office notes that the largest hurdle to transmission development will be the lengthy NEPA process, required when potential transmission projects cross state boundaries and traverse diverse terrain like buttes, valleys, canyons, and basins. The Utah Public Lands Coordinating Office states that NEPA requirements have become increasingly complex, which the Office represents as further amplified by the revised National Environmental Policy Act Implementing Regulations, enacted by the Biden Administration on April 20, 2022, which has led to increasingly complex NEPA requirements.

Extreme Weather Events

Many commenters, including Con Edison, EDF, AMPUA and IEDA, and others comment on DOE's discussion of the need for transmission to bolster system resilience and reliability during extreme weather events. For example, ACP states the importance of interregional transmission

[54] U.S. Department of Energy. 2023. National Transmission Needs Study: Draft for Public Comment, p. 41. Available at https://www.energy.gov/sites/default/files/2023-02/022423-DRAFTNeedsStudyforPublicComment.pdf.

in assisting in recovery from increasingly common extreme weather events. AEP mentions that with the increased intensity of weather events, transmission development is needed to make sure the grid is reliable. National Grid comments that climate change will continue to increase the intensity of weather events and therefore cause more transmission level outages.

Commenters point out how unprepared states are during extreme weather events, and go on to mention causes of grid failures, such as frozen pipelines and wind turbines. Commenters suggest that additional transmission interconnections could reduce impacts during such catastrophic events. PIOs agree with DOE's findings that that weather risks can be mitigated if utilities share generating resources, aid with restoration and recovery, and improve frequency response. SREA also highlights the importance of geographic diversity of generation resources in ensuring reliability and resiliency, and specifically mentions the potential expansion of the Regional Directional Transfer Limits promised to be included in Tranche 4 of MISO's LRTP as vital to future system reliability and resilience. NYTOs state that the development of new transmission will be key to accommodating the transition to clean energy resources, supporting higher demand due to electrification, and reinforcing the grid to withstand extreme weather events.

The Utah Public Lands Coordinating Office comments on the need to enhance reliability and resilience in the Mountain region, primarily due to the increased occurrence of power outages caused by extreme heat and wildfires becoming more common due to climate change. The Utah Public Lands Coordinating Office elaborates on Utah's restoration efforts and the potential for fires to damage energy infrastructure.

Con Edison, AMPUA, and IEDA note that new interregional transmission can connect geographically diverse resources, which can help the transmission system withstand extreme weather events. EDF recommends that DOE recognize that minor weather events also have significant impacts on resources and regions. EDF uses examples of data collected by the National Oceanic and Atmospheric Administration that show project weather trends.

The Blue Lake Rancheria Tribe recommends DOE discusses seismic activity in Humboldt and Del Norte counties, potential grid capacity shortfalls, the need for substation and distribution grid upgrades, and sea level rise when assessing energy system reliability and resilience needs specific to California.

The Blue Lake Rancheria Tribe further asserts that Tribal nations need to upgrade their energy infrastructure (including transmission, substation, and distribution) as many Tribal nation areas are rural, remote, and subject to multiple hazards. Tribal facilities are often the only critical infrastructure in rural and remote areas and climate resilient electrical infrastructure can deliver a wide array of emergency services.

Multiple organizations—including Grid United, SPIGs, SREA, and others—assert that the Study should include more information on Winter Storm Elliott. SREA explains how Winter Storm Elliott, along with other extreme weather events disrupted utility operations. ACORE recommends that DOE integrate the following resource into the analysis: The Value of Transmission During Winter Storm Elliott, Grid Strategies LLC (2023), which evaluates the benefits of how interregional connection would positively impact during the storm.

Newman states that aboveground transmission lines in remote areas only add risk to the system from wildfires, hurricanes, tornadoes, sabotage, and other grid failure events. Newman suggests that a smaller system in which load and generation are closer together decreases risk because there are fewer potential points for failure. Newman argues that modern technologies other than aerial wires should be deployed to minimize burdens, avoid private property conflicts, and reduce opposition to transmission projects.

SERTP Sponsors comment that while the Needs Study addresses its concern that transmission would not mitigate tornado events, the Study still inaccurately indicates that transmission would mitigate hurricane events. SERTP Sponsors argue that the Study should make clear that both tornadoes and hurricanes are extreme weather events with impacts that likely would not be mitigated by increased transmission capacity.

Department Response

Commenters note the draft Study fails to mention that transmission development has externalities that affect land use, natural ecosystems, farming, and tourism. In response, the Department has included additional references and context to *Section V.e. Siting and Land Use Considerations* to discuss how transmission siting must balance competing land use interests, along with a text box highlighting DOE work on transmission siting (pages 103–106). Additionally, see the Department Response to Section 2.4 above for a discussion on co-locating transmission in energy corridors.

In response to comments recommending transmission be built with appropriate community input on degraded lands or lands with existing rights-of-way, the Department has included, as noted in the Department Response to Sections 1.6 and 3.1 above, an additional subsection in *Section V.e. Siting and Land Use Considerations* to discuss of the importance of community, stakeholder, and Tribal engagement (pages 106–108). The Department also includes a text box discussing the Department's work on energy justice.

Several comments recommend DOE further recognize the role of extreme weather events in identifying transmission needs. The Department has expanded discussion of extreme weather and its impacts on the transmission system in *Section V.a. Reliability and Resilience* (pages 55–59). This expanded section includes numerous additional references suggested by commenters, including references to an extreme heat event in California, the 2014 polar vortex impacts to the Midwest and northeastern United States, and the 2018 "bomb cyclone" cold weather event, among other events. See additional comment resolutions related to extreme weather events in Department Response to Sections 2.2 through 2.4 above.

The Blue Lake Rancheria Tribe outlines several needs for improved energy system reliability and resilience, including seismic activity in Humboldt and Del Norte counties, grid capacity shortfalls, substation and distribution grid upgrades, and sea level rise. In response, the Department has expanded discussion of the risks posed by seismic activity in northeastern California, including impacts in Humboldt County, and sea level rise to *Section V.a. Reliability and Resilience* (page 59). The additional context provided on sea level rise, specifically the transmission system risk from hurricane-related storm surge, addresses SERTP's concern that the risk of hurricanes to the transmission system is not adequately explained in the draft Study.

In response to several commenters recommending the Study include more information on Winter Storm Elliott, the Department expanded discussion of Winter Storm Elliott in Section V.a. and incorporated various references provided by commenters to support additional information.

3.4. Other Transmission Issues

Several commenters express other concerns related to transmission, including the risks, limitations of, and alternatives to transmission expansion.

ERCOT argues that increased interregional transmission can increase reliability risk. ERCOT cites the January 2019 Eastern Interconnection event, which "put the entire Eastern Interconnection on the brink of a collapse." Furthermore, it cites resource adequacy concerns and argues that fewer regions will be equipped to support themselves or help neighboring systems during system disturbances if there is greater interdependency between regions. ERCOT urges DOE to address these concerns in the Study. Additionally, ERCOT states that additional transmission facilities would be needed to regulate stability and voltage if ERCOT increased connection to other regions, and notes this could be costly.

Keryn Newman objects to the Needs Study's "impossible goal to eliminate congestion on the grid." Newman argues that new generation, in regions with high prices, would be a more effective solution to solve economic congestion than new transmission lines. Newman objects to the Needs Study's statement that estimates of an additional 1 GW of transmission capacity between Texas and the Southeast would have saved customers $75 million during Texas's 2019 heat have. Newman argues that this estimate does not include the cost of building the transmission line and does not consider whether additional peaking generation in Texas would be a more cost-effective alternative.

The Center for Biological Diversity urges DOE to consider alternative ways to meet energy needs in addition to transmission expansion and argues that to meet mandates defined in the IIJA, Pub. Law 117-58, the Needs Study must address methods to minimize the adverse impact of transmission deployment on environmental and cultural heritage sites.

AEG notes that Sonny Anand, Director, Infrastructure Investments for National Grid, emphasizes the importance of stakeholder engagement in transmission coordination. AEG references Anand's discussion of a successful engagement model, which would benefit, among other things, from consideration of the economic impacts and potential adverse consequences of transmission development, especially when vulnerable communities are involved. AEG also references discussion that asserts that developers need to ensure new rights-of-way are identified, communicated, and adequately analyzed for community impact, share the benefits of new projects with impacted communities, and seek opportunities such as disadvantaged business set asides and training/apprenticeship programs to economically empower impacted communities.

Keryn Newman objects to the Needs Study's statement that "large amounts of low-cost generation potential exist in the middle of the country and accessing this generation through increased transmission is cost-effective for neighboring regions." Newman argues this approach is only low-cost due to taxpayer-funded subsidies and lower-cost lands and that "turning rural America into an energy serfdom to provide power to far-away cities" benefits urban communities that do not want to build infrastructure in their own backyard. Newman also argues that the statement exhibits "cultural and political elitism." Furthermore, Newman argues that the Study dismisses legitimate landowner concerns as "NIMBYism" and barriers to transmission development without attempting to address them. Accordingly, Newman concludes that the Study lacks awareness and empathy.

Two commenters identify obstacles to transmission investment. Monitoring Analytics emphasizes the need for competitive transmission development. Furthermore, it notes the need for mechanisms that allow transmission planners to compare the costs, risks, and benefits of transmission development versus generation development. Additionally, Monitoring Analytics explains that transmission projects tend to exceed their estimated costs, which should be reflected in any robust cost-benefit analysis.

Avangrid supports DOE's statement that New England's constrained natural gas system poses reliability concerns in the winter when gas demand is high for both heating and electricity. Similarly, National Grid acknowledges the risk of natural gas constraints in New England and adds that these risks are exacerbated by cold winters, electric heating, and dependence on internationally imported fuels. It asserts that interregional transmission capacity can reduce these reliability concerns.

NEMA remarks that large power and distribution transformers are vital components of the grid, and long lead times on delivery could compromise grid operations and prevent power delivery to end-users.

The Blue Lake Rancheria Tribe encourages DOE to consider its reliability and resiliency needs. The tribe details existing capacity constraints, which limit renewable development options, and emphasizes the need to upgrade the single 115 kV line supplying power to its region.

Department Response

In response to commenter concerns that increased interregional transmission can have local and regional impacts, see Department Response to Section 1.6 of this comment synthesis. In response to commenter concerns about eliminating congestion in an economically efficient way, see the Department Response to Section 2.3. In response to commenter requests for project cost analyses and supply chain issues, see the Department Response to Section 2.4. In response to comments on risks posed by winter gas supply, see the Department Response to Section 2.5.

In response to concerns of Tribal energy needs, environmental degradation, landowner concerns, and stakeholder engagement during siting activities, see the Department Response to Sections 1.6, 2.2, 2.4, 3.1, and 3.3. The Department stresses that addressing landowner concerns is critical to ensuring just and equitable outcomes in transmission deployment. The Needs Study makes no reference to "NIMBYism" and the Department has taken care to ensure that landowner concerns are not presented as a barrier to transmission deployment in the final Study.

In response to commenter concerns about finding alternative means to meet energy needs, the Department did include a lengthy discussion on numerous transmission technologies, which is available in *Section V.d. Alternative Transmission Solutions* (pages 89–95). The Department additionally stresses that "transmission" is meant to be technology neutral and there are often numerous technologies that can be used to meet transmission needs. The Department further notes that alternative solutions can help lower, but are unlikely to eliminate, the need for traditional "poles and wires" solutions. See pages 118–119 for further discussion.

4. Technology

4.1. Alternative Transmission Solutions

Approximately 18 commenters substantively discuss the importance of GETs in meeting transmission needs. Most of these commenters suggest that DOE expand its discussion on GETs and other NWAs.

ACP, the Center for Biological Diversity, AE, AES, ACORE, and others appreciate DOE's acknowledgment of the role GETs can play in optimizing the transmission system and complementing existing grid infrastructure. AES supports DOE's needs-based, technology-agnostic approach, which includes both traditional wires and substations, as well as reconductoring and storage-as-transmission, digital improvements through DLR, topology optimization, power flow controls, and demand-side solutions.

The WATT Coalition, NEMA, LineVision, the Center for Biological Diversity, AEU, and AE encourage DOE to increase the focus on GETs and their ability to increase transmission capacity. The Center for Biological Diversity mentions that the Study fails to adequately explore NWAs as a solution to energy needs, emphasizing that NWAs should be considered the first line of offense instead of new transmission infrastructure and encourages DOE to consider the Center's comments on DOE's Grid Resilience and Innovation Partnerships Program. The WATT Coalition mentions its strong support for the following statement in the Needs Study: "When capacity expansion models find that new GW or GW-miles of transmission capacity is needed in a particular region, this could be met, at least in part, by increasing the carrying capacity of existing grid infrastructure already within the region." The WATT Coalition asserts that by adding citations to reports and studies it references in its comments, DOE can better quantify this statement. LineVision recommends a "transmission loading order approach where optimization of the grid (via the utilization of low-cost tools such as GETs) is considered first, then grid reinforcement, and then grid expansion," using customer affordability as a guiding principle. AE and the WATT Coalition recommend that the Needs Study incorporate the Study, *Unlocking the Queue with Grid-Enhancing Technologies*,[55] which found that GETs enable increased integration of renewables and lead to substantial production cost savings, emissions reductions, and economic benefits.

[55] Tsuchida T, Ross S, and Bigelow A. 2021. Unlocking the Queue with Grid-Enhancing Technologies. Available at https://watt- transmission.org/wp-content/uploads/2021/02/Brattle Unlocking-the-Queue-with-Grid-Enhancing-Technologies Final-Report Public-Version.pdf90.pdf.

LineVision explains that utilizing DLR can also address some of the needs DOE identifies in the Study. AES discusses the various benefits of DLRs.

The WATT Coalition and other commenters recommend DOE add language that elaborates on the benefits of GETs. Referencing Section IV, the WATT Coalition notes that the report on transmission investment does not mention increased adoption of GETs by U.S. utilities and provides a list of GET deployment case studies for DOE to review.

NEMA also supports the utilization of GETs to make existing lines smarter and more efficient. It claims GETs can help satisfy immediate needs and states that NWAs should be considered on par with new transmission. For example, NEMA notes that replacing legacy steel-core wires with high-temperature, low-sag conductors allows for increased capacity through a transmission corridor and over a longer distance. NEMA mentions that combining hardware upgrades with software technologies can help to satisfy transmission needs more quickly. However, NEMA notes that modernizing existing HVDC lines alone will only generate "marginal benefits for the grid as a whole," and therefore near-term transmission development and installation is crucial for a successful energy transition.

ACORE suggests that transmission planning and interconnection studies should incorporate GETs.

AMPUA and IEDA appreciate that DOE discuss other NWAs (pages 73–75 of the Study). Furthermore, AMPUA and IEDA mention that cost comparisons of NWAs would be helpful to assist in short- and long-term planning in order to compare alternatives. AMPUA and IEDA also say that not including vegetation management as a mitigation alternative is a weakness of the Study, as they believe vegetation management is the timeliest NWA.

The Center for Biological Diversity indicates that energy efficiency is not discussed and stresses the importance of distributed energy generation and storage in meeting U.S. energy needs, stating that there is substantial technical potential of distributed solar. The Center also describes the benefits of DERs, especially paired with storage, and references several instances in which DERs powered homes and businesses during Hurricanes Maria, Fiona, and Irma. Because communities of color disproportionately bear the brunt of impacts from system failures during extreme weather events, the Center also suggests that implementing NWAs will support these communities.

NHA adds that DOE should include pumped storage in its analysis, specifically as an NWA, and states that there are NREL studies available for DOE to review. It also mentions that DOE should consider electrifying non-powered dams and marine energy as potential alternatives to new transmission lines. Xcel Energy mentions its interest in DOE broadening technology considered in the Study, including exploring long-duration battery storage.

Other specific requests include those by AMP, which suggests the NWAs section be renamed, "Advanced Transmission Technology" to align better with previous DOE reports and to incorporate high-ampacity conductors in this section. AMP explains that high-capacity conductors are not NWAs but are an advanced transmission technology, which can increase transfer capacity and provide many other benefits. AMP explains that high-ampacity conductors can ultimately save ratepayers money and reduce the need for additional generation. AMP further claims superconductors would enable higher renewable integration. Lastly, AMP notes that many of the statements DOE has made about NWAs in the Needs Study also apply to high-ampacity conductors.

The Blue Lake Rancheria Tribe cites that transmission upgrades need to be designed with sufficient capacity for Tribal nations' DER development and other opportunities.

Expand Discussion of Alternative Transmission Solution Benefits

Several commenters, including ACP, the Center for Biological Diversity, AE, the WATT Coalition, and others, elaborate on the benefits of alternative transmission solutions and advocate for DOE to provide further discussion benefits in the Needs Study. For instance, the Center for Biological Diversity states that the Study largely ignores the benefits of NWA, including greater affordability, greater resilience in extreme weather events, economic benefits, avoided wildlife impacts and waste of power lost in transmission, and public health benefits from displacing fossil generation. AE reiterates that GETs can complement existing grid infrastructure and optimize the amount of transmission needed. AE also mentions the importance of GETs in system optimization, reliability, increased renewable energy deployment, and supporting affordable costs for customers. The WATT Coalition reviews the benefits of GETs, including increased grid capacity, increased flexibility, greater situational awareness, reduced congestion costs, integration of low-cost generation, and maximized value of new transmission investment. Similarly, LineVision mentions the benefits of relief during outages, improved reliability, increased and flexible capacity, increased renewable integration, reduced curtailments and congestion relief, citing grid optimization efforts in New York State that recognize the benefits of advanced transmission technologies like DLR. Additionally, LineVision emphasizes that DLR technology can quickly increase transmission capacity, supporting the existing grid while new transmission is built, and therefore filling short-term needs while new transmission projects are planned over a longer-term timeline. LineVision and the WATT Coalition reference The Brattle Group's *Building a Better Grid: How Grid-Enhancing Technologies Complement Transmission Buildouts*[56] paper, which outlines the following benefits of GETs before, during, and after construction:

- Before: GETs can reduce congestion by at least 40%.
- During: Outages can be avoided, with similar reductions in congestion as above.
- After: Utilization on new lines can increase by 16%.

The Center for Biological Diversity references the Environmental Law and Policy Center's 2021 report on NWAs, which explains that GETs can substantially increase effective line capacity and preclude the need for additional transmission infrastructure.

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[56] Tsuchida B, Bai L, and Grove J. 2023. How Grid-Enhancing Technologies Complement Transmission Buildouts. Available at https://www.brattle.com/wp-content/uploads/2023/04/Building-a-Better-Grid-How-Grid-Enhancing-Technologies-Complement-Transmission-Buildouts.pdf. .

AES specifically discusses the benefits of storage-as-transmission, including flexible peaking capacity, system stabilization, transmission congestion mitigation, renewable resource integration, and other benefits.

However, EEI highlights the limited potential of GETs, arguing that while some GETs referenced in the Needs Study—DLR, power flow controllers, and topology optimization—enable operational flexibility in the short-term, they are not replacements for transmission. EEI states that GETs "should be encouraged but not required as part of a transmission project." Further, EEI notes DLRs have limited use in planning studies.

Barriers

A couple of commenters suggest that DOE expand its discussion on technological barriers. The WATT Coalition asserts that Section V.i Barriers to Transmission Development should include barriers to transmission optimization, such as the incentive misalignment regarding the return-on-equity business model of for-profit transmission owners and recommend citing research by Gramlich and Tsuchida, and other existing research described in item IV.c of their comments.[57]

AE specifically recommends that the Needs Study recognize the barriers that storage resources and GETs face in current transmission planning and interconnection processes, expressing their concern that Needs Study is reinforcing the inherent biases in existing transmission planning processes for traditional solutions. AE claims that assumptions used in interconnection studies poorly reflect the flexibility of storage operations, which leads to higher interconnection costs.

Future Efforts

Some commenters recommend DOE engage in future efforts not directly related to the Needs Study. AE states that DOE should review policies that prevent the proper consideration of alternatives in transmission planning processes and requests that DOE commit additional resources to the exploration of how GETs can alleviate regional needs identified in the Study. Specifically, AE encourages DOE to fund studies that look into opportunities for GETs to alleviate transmission needs. Additionally, AE encourages DOE to perform a study that investigates how to incorporate GETs into transmission planning processes.

AEG specifically states that stored energy should be incorporated into planning, design, and deployment.

Department Response

Commenters suggested the Department relabel Section V.h. of the draft Study to "Advanced Transmission Technologies" rather than "Non-Wires Alternatives" to be inclusive of more technologies and to be consistent with previous DOE reports on the subject. Commenters also suggested the Department incorporate advanced conductors and cables into the final Study. In response, the Department refers to both GETs and advanced conductors and cables as

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[57] Tsuchida B, and Gramlich R. 2019. Improving Transmission Operation with Advanced Technologies: A Review of Deployment Experience and Analysis of Incentives. Available at [Brattle-Grid-Strategies-Paper-ImprovingTransmissionOperationWithAdvancedTechnologies.pdf (smartwires.com)].

advanced transmission technologies but relabels Section V.d. in the final Study as "Alternative Transmission Solutions" to refer to the suite of tools and technologies discussed, which also include storage, DERs, and microgrids. In addition, the Department adds a subsection to *Section V.d. Alternative Transmission Solutions* dedicated to advanced conductors and cables (page 94) and their ability to increase transmission transfer capacity in both new transmission infrastructure projects and existing infrastructure rebuilds and upgrades.

Several commenters requested the Department expand its discussion of GETs to include more information regarding specific types of GETs and their associated benefits. In response, the Department has expanded *Section V.d. Alternative Transmission Solutions* (pages 89–95) in the final Study to provide more information on various GETs referenced in the draft Study. Information specific to GETs is on pages 92–94. The Department has incorporated one new reference directly recommended by commenters in the final Study that outlines the impacts of certain GETs on the power grid, benefits to ratepayers, and the ability for GETs to complement traditional transmission expansion. In all, six new references were added to the expanded *Section V.d. Alternative Transmission Solutions* in the final Study.

Certain commenters express concern that the Department is reinforcing the inherent biases in existing transmission planning processes for traditional wire solutions, while others request the Department to clarify the limited potential of GETs. The Department continues to use the "transmission" as a technology-neutral term and applies this term to both wire and non-wire transmission facilities, unless explicitly stated otherwise. The Department does, however, note in the Executive Summary, Section V.d., and Section VI that advanced transmission solutions could help reduce, but are unlikely to eliminate, the need for new "poles and wires" transmission infrastructure.

Additionally, various commenters suggested the Department expand its discussion on the barriers to alternative transmission solution deployment, including challenges related to transmission planning and interconnection processes. The Department notes a comprehensive analysis of barriers within current transmission planning and interconnection processes is beyond the scope of this Study. The Department does, however, include a recommendation that planning entities may wish to incorporate advanced transmission solutions as part of their existing planning processes into *Section I.a. How to Use This Needs Study* of the final Study.

4.2. Generation Resources

Several commenters provided feedback related to generation sources considered in the Needs Study. AMPUA and IEDA appreciate DOE's acknowledgment of the role of resource diversity in enhancing resilience and encourage an "all of the above" approach to ensure grid reliability. They point out that resource diversity in ISO-NE reduced the need for new capacity by up to 17 GW and support the Study's acknowledgment of the capacity shortfalls in MISO and WECC.

Martyn Roetter explains that much more generation capacity will be required to fully decarbonize the grid, which could be moderated by technologies such as demand management and energy storage systems. Roetter notes that more high-capacity resources will be needed in the future to guarantee grid reliability and resilience, as electrification and weather variability cause significant demand fluctuation.

The Utah Public Lands Coordinating Office discusses the value of geothermal resources, especially in stabilizing the grid as a baseload resource with the increased penetration of intermittent wind and solar. The Office also elaborates on the challenges of expeditiously developing geothermal projects.

JHI and NHA advocate for the Study to include additional discussion on hydrokinetic energy and hydropower. JHI and NHA both suggest that the Study include the benefits of hydropower and hydrokinetic energy as growing national energy resources, as well as the implications and projected economic and environmental benefits. NHA notes the potential for marine energy to serve as a potential alternative to new transmission. JHI explains that hydropower and hydrokinetic locations are sometimes far from existing grid infrastructure, making it economically challenging and financially impractical to interconnect projects. However, as the grid becomes strained, JHI and NHA argue that potential hydropower projects and associated interconnected transmission possess new national value and value proposition because they deliver firm power to support intermittent energy resources and provide national security and decarbonization enhancements. Therefore, JHI and NHA encourage DOE to consider an analysis that would identify potentially constrained hydropower projects which would be viable if additional transmission were built to access the hydropower and hydrokinetic resources. JHI references Chapter 3: Assessment of National Hydropower Potential of DOE's 2016 *Hydrovision Report*,[58] to identify untapped national hydropower resources.

Furthermore, JHI asks DOE to give more consideration to large and small fish-friendly hydropower development and requests that American-developed and -produced hydro resources receive the same consideration as other renewable resources identified in the Study. NHA also recommends that DOE consider non-powered dams that could be electrified.

Lastly, ACC argues that natural gas should be incorporated into DOE's analysis, given it is secure, reliable, and contributes to lowering emissions on the grid.

Department Response

The Department thanks commenters for their comments related to generation resources. Given the intended focus on the transmission system, the Department has opted not to incorporate recommendations regarding discussion of specific generation resources. The Department has instead made revisions throughout to make discussion surrounding generation in the final Study to be more technology neutral, distinguishing generation technologies based on their implications for the transmission system instead of their carbon emissions. See Department Response to Section 2.4 of this comment synthesis for additional discussion on how generation diversity is framed in the final Study.

The Department acknowledges commenters' concerns that discussions of wind and solar energy heavily outweigh other generation technologies. These specific generation technologies, which are being adopted rapidly, have unique implications for the transmission system. Most

[58] U.S. Department of Energy. 2016. Hydropower Vision Chapter 3, Assessment of National Hydropower Potential. Available at https://www.energy.gov/node/1922621/.

notably, the variable nature of these resources' generation has reliability considerations that firm resources—such as natural gas, hydropower, and geothermal energy—do not. Studies have also shown that both land-based and OSW energy technologies require interregional planning that differs from many historic regional transmission planning processes. Discussion of these energy sources has been reframed in the final Study to specify implications for the transmission system.

4.3. Offshore Transmission

Several commenters recommend that DOE expand its discussion on OSW and offshore transmission. The PIOs highlight the lack of OSW-related transmission needs identified in the Needs Study and indicate that the Study should incorporate existing studies that identify this need.

ACP appreciates the Study acknowledging that existing transmission capacity cannot support the growing number of OSW projects, as many coastal transmission facilities are lower voltage. ACP explains that integrating OSW will drive significant upgrades to coastal transmission systems on a generator-by-generator basis, but these upgrades will not sustain the expected OSW deployment needed to meet state and federal policy goals.

A few commenters discuss the planning required for OSW development. SPIGs state that the Needs Study inadequately expresses the urgency for coordinated planning efforts needed to integrate OSW. Specifically, SPIGs recommend that DOE acknowledge the benefits of coordinated transmission development on the East Coast. SPIGs describe available OSW capacity off the coast of North Carolina and explain that a coordinated approach to OSW transmission will reduce the number of required interconnections. Additionally, SPIGs illustrate a backbone transmission system, or "an ocean grid" that would cost-effectively address the challenges of interconnecting OSW capacity to the onshore grid.[59] Con Edison states that DOE's efforts are helpful in recognizing future needs and encouraging productive discussion on coordinated transmission planning and development, especially to advance the integration of OSW. NYTOs stress the importance of a coordinated approach to OSW development, especially to optimize the use of constrained waterways in dense, urban areas. National Grid recommends that DOE examine both onshore and offshore resources when discussing interregional planning.

The Blue Lake Rancheria Tribe asserts that Tribes need to be involved early in planning for OSW transmission upgrades. The Blue Lake Rancheria Tribe claims that upgrades, planned with sufficient capacity to connect OSW to Tribal Nations, would be significantly more effective and introduce opportunities for Tribal support and transmission development. In reference to the Needs Study's Offshore Wind Section, the Blue Lake Rancheria Tribe adds that there is potential for ~15–45 GW of OSW generation off the Northern California/Southern Oregon coasts, but to deliver OSW power to load centers to the east, south, and north, new high-voltage transmission lines must be built.

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[59] Levitan & Associates, Inc. 2020. Offshore Wind Transmission: Study Comparison of Options, p. 6. Available at https://www.nj.gov/bpu/pdf/publicnotice/Transmission%20Study%20Report%2029Dec2020%202nd%20FINAL.pdf.

Two commenters provide insight into OSW needs in New York. Con Edison mentions its high priority of planning for the integration of OSW, noting its current project in development—the Brooklyn Clean Energy Hub—and the need for coordinated transmission solutions to connect OSW resources to the grid. Con Edison advises DOE to consider the need to expand transmission in New York to connect OSW resources. NYTOs reference several studies by New York that indicate the benefits of developing a meshed offshore transmission network,[60,61] including discussion of offshore networks linking New York with New Jersey and New England.[62]

Similarly, PSEG supports the Study's finding that there is an immediate need for "an offshore backbone grid to support state policies for offshore wind generation," but states that the Study should also recognize the need to establish a fully networked system rather than a network-ready system. Specifically, in response to DOE's statement that "an offshore grid designed and built with the capability of a networked system will provide more benefits and will better facilitate the integration of (OSW) resources compared with each OSW resource connecting to the onshore grid through a dedicated generator lead line," PSEG asserts that "a network-ready system will only delay implementation and lead to increased costs later on, as technologies developed today will be obsolete or require [costly] upgrades." PSEG goes on to mention that a networked system to support OSW generation provides economic, reliability, resiliency, and other benefits. PSEG references New York State Energy Research and Development Authority's meshed grid study identifying approximately $60 million in annual savings for New York ratepayers.[63]

Several commenters encourage DOE to consider OSW needs in other regions outside of the Atlantic coast:

- ACP and the PIOs recommend DOE consider OSW as a driver of transmission in other regions of the country, such as the Gulf of Mexico, the West Coast, and the Great Lakes. PIOs suggest that DOE initiate studies to analyze how different coordinated transmission solutions would enable OSW in these regions and subsequently undertake an interim Needs Study when such regional studies are available.

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[60] New York Department of Public Service and New York State Energy Research and Development Authority. 2021. Initial Report on the New York Power Grid Study , p. 69 and 75. Available at https://www.nyserda.ny.gov/-/media/Project/Nyserda/Files/Publications/NY-Power-Grid/full-report-NY-power-grid.pdf.

[61] Pfeifenberger J, Tsoukalis J, Newell S. 2021. The Benefits and Cost of Preserving the Option to Create a Meshed Offshore Grid for New York, p. 8. Available at https://www.brattle.com/wp-content/uploads/2021/12/The-Benefit-and-Cost-of-Preserving-the-Option-to-Create-a-Meshed-Offshore-Grid-for-New-York.pdf.

[62] State of New York Public Service Commission. 2022. Proceeding on Motion of the Commission to Implement Transmission Planning Pursuant to the Accelerated Renewable Energy Growth and Community Benefit Act, NYPSC Case 20-E-0197, et al. Order on Power Grid Study Recommendations, p. 11. Available at: https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={23F0F463-A059-4CFC-9134-4535F660611F}.

[63] Pfeifenberger J, Tsoukalis J, Newell S. 2021. The Benefits and Cost of Preserving the Option to Create a Meshed Offshore Grid for New York, p. 8. Available at https://www.brattle.com/wp-content/uploads/2021/12/The-Benefit-and-Cost-of-Preserving-the-Option-to-Create-a-Meshed-Offshore-Grid-for-New-York.pdf.

- SREA suggests that the Needs Study consider increased interregional capacity between Texas and Louisiana to integrate OSW in the Gulf of Mexico.
- SPIGs indicate that the Study has not fully explored the development of OSW in the Southeast and Mid-Atlantic and the unique transmission needs that would be required to accommodate such development.
- TDI-NE refers to studies by the Massachusetts Institute of Technology, the State of Massachusetts, and the State of Connecticut that indicate increased transmission capacity with Québec is the lowest cost option that maximizes the value of New England's OSW potential.

Several commenters suggest additional resources, related to OSW, for DOE to consider in the Needs Study. These are itemized below.

- National Grid's comments focus on integrating offshore resources on the Atlantic coast and discuss the benefits of interregional transmission, specifically related to the OSW integration. The utility references NREL's Atlantic Offshore Wind Transmission Study, recommending that DOE consider how the results of the Needs Study and NREL's study interact, especially as they relate to interregional transfers.
- PSEG recommends that DOE update the Needs Study to reflect the 40 recommendations outlined in the updated Atlantic Offshore Wind Transmission Study referred to in the Needs Study.[64]
- PIOs urge DOE to incorporate its findings from the 2021 Atlantic Offshore Wind Transmission Literature Review and Gaps Analysis along with other relevant studies.[65,66,67,68]
- SPIGs provide several attachments as resources to DOE, including Johannes P. Pfeifenberger et al., *The Benefit and Urgency of Planned Offshore Transmission:*

[64] U.S. Department of Energy. 2021. Atlantic Offshore Wind Transmission Stakeholder Workshop slides 30–58. Available at https://www.energy.gov/sites/default/files/2023-04/DOE%20GDO%20AOSW%20Workshop%20Presentation%20032223%20Final_508.pdf.

[65] U.S. Department of Energy. 2021. Atlantic Offshore Wind Transmission Literature Review and Gaps Analysis. Available at https://www.energy.gov/sites/default/files/2021-10/atlantic-offshore-wind-transmission-literature-review-gaps-analysis.pdf.

[66] Pfeifenberger J, DeLosa III J, Bai L, Plet C, Peacock C, Nelson R. 2023. The Benefit and Urgency of Planned Offshore Transmission: Reducing the Costs of and Barriers to Achieving U.S. Clean Energy Goals. Available at https://www.brattle.com/wp-content/uploads/2023/01/Brattle-OSW-Transmission-Report_Jan-24-2023.pdf.

[67] Smith K, Lenney S, Marsden O, Kates-Garnick B, Stanković A, Hines E. 2021. Offshore Wind Transmission and Grid Interconnection across U.S. Northeast Markets. Available at https://createsolutions.tufts.edu/wp-content/uploads/2021/08/OSW-Transmission-and-Grid-NE.pdf.

[68] PJM Interconnection. 2021. Offshore Wind Transmission Study: Phase 1 Results. Available at https://www.pjm.com/-/media/library/reports-notices/special-reports/2021/20211019-offshore-wind-transmission-study-phase-1-results.ashx.

Reducing the Costs and Barriers to Achieving U.S. Clean Energy Goals, The Brattle Group (Jan. 24, 2023).[69]

- ACORE recommends that DOE review and incorporate The Benefit and Urgency of Planned Offshore Transmission: Reducing the Costs of and Barriers to Achieving U.S. Clean Energy Goals into the Needs Study, which discusses how offshore transmission development can cost effectively integrate offshore wind and provide resiliency benefits to the onshore grid.[70]

Department Response

Several commenters recommend that DOE expand its discussion on OSW and offshore transmission and expand the Study to incorporate offshore transmission beyond the Atlantic coast. In response, the Department has included additional information related to offshore transmission in Section *V.c. Generation and Demand Changes* of the final Study (pages 81–83). New information includes a discussion of how emerging offshore energy generation industries, which require unique transmission planning with new jurisdictional questions, can result in reliability implications for connecting to the land-based transmission system. Eleven additional references were included in the final Study, most of which are either Department or industry reports and several were suggested for inclusion by commenters. Among the new resources is preliminary analysis from the Department's Atlantic Offshore Wind Transmission Study.

In response to the Blue Lake Rancheria Tribe assertion that Tribes need to be involved early in planning for OSW transmission upgrades and as noted in the Department Response of Section 1.6 above, the Department has added a discussion of the need for community, stakeholder, and Tribal engagement during the transmission development process to pages 106–108 of *Section V. Siting and Land Use Considerations* in the final Study. Additionally, the Department has recently launched the Tribal Nation Technical Assistance Program for Offshore Wind Transmission program, which offers technical assistance, trainings, and participation support funds to help Tribes successfully engage transmission planning and development for OSW in the United States.

4.4. Other Technologies

Some commenters mention additional technologies for DOE to consider incorporating into the Needs Study.

Xcel Energy asks DOE the following questions:

- "Is it possible to broaden the technology assumptions used for the generation resource mix to analyze the benefits of dispatchable clean energy resources? There seems to be a bias to a very heavy renewable energy future rather than a more comprehensive set of resource types, like inclusion of green hydrogen and advanced nuclear technologies.

[69] Pfeifenberger J, DeLosa III J, Bai L, Plet C, Peacock C, Nelson R. 2023. The Benefit and Urgency of Planned Offshore Transmission: Reducing the Costs of and Barriers to Achieving U.S. Clean Energy Goals. Available at https://www.brattle.com/wp-content/uploads/2023/01/Brattle-OSW-Transmission-Report_Jan-24-2023.pdf.

[70] Ibid.

- Does the Study incorporate DOE funding of various hydrogen hubs throughout the country and the likely propensity of hydrogen adoption in CT and CC technologies?"

The Center for Biological Diversity notes that Grid-Interactive Efficient Buildings (GEBs) can assist with energy needs by shifting building demand to times of high peak supply, decreasing utility and customer costs, reducing the need for new transmission and distribution builds, and improving climate resilience. The Center also discusses energy efficiency initiatives, reviewing various benefits of deploying energy efficiency and conservation technologies.

To decarbonize the U.S. electricity system by 2050, AES explains that the United States cannot rely solely on new transmission builds, but also needs to support new and other market-available technologies that quickly address transmission needs. AES also lists several technology-neutral use case descriptions for DOE to reference and detail the benefits of aggregations of energy and enhanced grid visualization and simulation software.

AMP discusses the benefits of high-ampacity conductors, which include quickly increasing grid capacity, energy efficiency, and resilience, relieving underlying grid congestion, and interconnecting more clean energy. AMP emphasizes that high-ampacity conductors are advanced transmission technology that should be considered in the Study.

Martyn Roetter discusses his concerns surrounding green hydrogen and its impact on the demand for electricity. Roetter is also concerned about the definition of "clean" in the context of "clean hydrogen," as Roetter explains that green hydrogen production via electrolysis is electricity intensive.

Roetter would like DOE to confirm that Study scenarios of future grid loads of 7,000 TWh to 8,000 TWh by the 2040s do not account for demands for clean grid-connected electricity to produce green hydrogen or power carbon dioxide removal systems. Roetter assumes that load increases in the Study scenarios are largely driven by electrification of buildings and transport.

Roetter mentions that projected green hydrogen demand (22–41 million tonnes annually in the United States), will require 1,000–2,000 TWh of clean electricity. Roetter outlines the following two questions, requesting DOE to address them by utilizing future transmission scenarios derived from reliable, integrated coordinated energy planning that also considers electricity demand for purposes beyond direct delivery to end uses over the grid:

- "Do the scenarios in the Transmission Needs Study include a substantial grid load for producing hydrogen or do they assume that other dedicated sources of clean electricity not connected to the grid will be used to power the electrolysers?
- If alternatively clean electricity from the grid is used in significant quantities to produce green hydrogen, and/or for any other purpose than direct delivery to electrified applications, what will be the impact on the pace and extent of grid decarbonization over time, and hence on progressively eliminating anthropogenic emissions to achieve growing reductions in annual emissions in 2030, 2040, 2050 and subsequently?"

Similarly, SREA suggests that DOE consider the needs driven by the growth of green hydrogen and incorporate assumptions "for hourly matching of hydrogen production with renewable energy."

Additionally, Vijayasekar Rajsekar encourages DOE to expand on its consideration of the need for communications and control systems infrastructure—including advanced grid monitoring services like Supervisory Control and Data Acquisition (SCADA), Energy Management System (EMS), and Inter-control Center Communications Protocol (ICCP) technologies—explaining that "a collaboration team of top power professionals, national labs engineers and SCADA/EMS vendors could effectively design and implement the best scenario for the U.S. National Grid system." Rajsekar proposes establishing a National Grid Control Center in Washington, D.C., and updating existing ISO Regional Grid Control Centers to monitor and coordinate all interregional transmission flows. Rajsekar explains in detail an approach to developing a "National Transmission Grid," which includes five phases described in his comment.

NEMA recommends that interested parties consult with manufacturers to better understand how existing technologies that are not typically considered can provide solutions to transmission needs.

Department Response

The Department thanks commenters for their comments regarding other technologies.

In response to requests for additional modeling or scenario assumptions in modeling, see Department Response to Section 2.4, which outlines that the Needs Study is an assessment of previously conducted analysis only and does not include new grid modeling. For additional discussion on demand-side solutions and energy efficiency, see Department Response in Section 2.2. In response to suggestions to include alternative transmission technologies and high-ampacity conductors, see Department Response in Section 4.1.

The high load growth scenarios that make up the High/High scenario group used in *Section VI. Anticipated Future Needs Assessment through Capacity Expansion Modeling* do include scenarios with grid-connected hydrogen production. Both grid-connected hydrogen production and direct air carbon capture and sequestration technologies were primary drivers of high demand in many of these scenarios. In response to commenter questions on hydrogen, the Department added clarification that hydrogen is included on pages 116, 119, and 125. For a more detailed discussion of how hydrogen is modeled in the underlying capacity expansion studies, the Department directs the commenter to review the scenarios included in each scenario group, provided in Table S-6 (pages 40–43) of the Supplemental Material, and the source documentation specific to each relevant capacity expansion study.

The Department has determined the inclusion of communications and protection protocols identified in comments received are beyond the scope of this Study.

5. DOE Statutory Authority and Designation of National Interest Electric Transmission Corridors

5.1. Support

ACP, ACORE, CEBA, SREA, PIOs, DCC, EDF, and others all maintain that the Study is well within DOE's authority under Section 216, as amended by IIJA. EDF states that DOE has "fulfilled its longstanding mandate" in conducting a study of congestion and capacity constraints. EDF and others confirm that DOE's definition of "transmission need" aligns with Congress's intent under FPA Section 216(a).

Similarly, PIOs explain that Section 216 does not limit DOE's analysis to existing or historical conditions, but instead outlines that DOE may designate a NIETC where there is existing *or future* transmission congestion or constraints. PIOs indicate that Section 216(a)(4) also references several factors that can be considered in NIETC designation, including national energy policy and security interests, economic growth, and diversification of resources. Because the Needs Study serves a primary role in in NIETC designation, PIOs state it is necessary for DOE to broadly assess the multiple drivers of existing and future transmission needs. Con Edison notes that although it currently takes no position on NIETC designation, it supports DOE using its findings to stimulate interregional discussions.

Several commenters, including ACORE, SREA, SPIGs, and PIOs, disagree with comments from SERTP Sponsors, who argue that the Needs Study is overly broad and exceeds the statutory provisions. ACORE asserts that such breadth is needed to demonstrate that current capacity constraints and congestion prevent the system from achieving transmission benefits, including accessing more cost-effective generation and improved reliability and resilience.

SPIGs contextualize SERTP Sponsors' comments, stating the following:

"As the utilities tasked with transmission planning in the Southeast, the SERTP is in large part responsible for the needs identified in the Draft Study and these comments. Their attempts to discredit the Draft Study's findings and diminish the Department's authority to catalogue the region's transmission needs must be viewed in the context of their historic underinvestment in regional and interregional transmission. Contrary to the assertions of SERTP Sponsors, the Department's mandates under the Federal Power Act (FPA), the IRA, and the IIJA are sufficiently broad to encompass the scope of this Draft Study, with room to spare. SERTP's unfounded criticisms should not deter the Department from releasing a fulsome assessment of the transmission system's existing deficiencies, however poorly that may reflect on the planning processes that produced them."

Similarly, EDF addresses comments to DOE made by other entities that suggest DOE has exceeded its authority by assessing future needs. EDF argues that these commenters disregard DOE's statutory obligation to produce a study that identifies expected transmission congestion and constraints. EDF claims that limiting the Study to historical conditions would conflict with congressional directive. EDF also emphasizes that "commenters suggesting that DOE should leave analysis of issues like projections of future demand and generation to 'NERC-registered transmission planners and transmission owners' would have DOE abdicate these responsibilities, which Congress specifically assigned to DOE and expanded in recent legislation."

ACP mentions that a subsequent report by DOE is necessary to designate NIETCs. ACP suggests DOE clarify that applicants may submit proposals for "narrowly tailored §216(a)(2) reports (designating a NIETC for specific lines that would address one or more needs identified in the final Needs Study)," which ACP notes is within DOE's authority.

Avangrid urges DOE to quickly proceed in designating NIETCs on a route-specific, applicant-driven basis and consider how potential corridors address unique regional needs.

Additionally, JHI notes that the scope of the Needs Study is not limited exclusively to FPA Section 216(a), and therefore should consider Alaska transmission needs.

Regarding DOE's statutory obligation "to consult with affected States, Indian Tribes and regional organizations in preparing the draft Transmission Needs Study," EDF mentions that DOE has undoubtedly met its obligation. However, EDF still urges DOE to go beyond just meeting the statutory minimum and consult with potentially affected communities and nongovernmental organizations with expertise in transmission capacity and congestion.

Department Response

Several commenters recommend that the Department clarify aspects of the NIETC designation process. In response, the Department has included additional context in *Section I. Introduction* of the final Study to clarify the Study's relationship with the Department's NIETC designation process (pages 1–2). See the Department Response in Section 1.4 above for additional discussion.

In response to JHI's comments regarding the inclusion of Alaska's transmission needs into the final Study, the Department has incorporated both Alaska and Hawaii into the final Study. Please see the Department Response of Section 2.3 for additional information on how these states' transmission needs were incorporated.

5.2. Opposition

Approximately four commenters express concern that the scope of the Needs Study exceeds DOE's authority under FPA Section 216. SERTP Sponsors provide the most substantive feedback regarding this concern, insisting that the Needs Study is overly broad, and not a reflection of the statute. SERTP Sponsors explain that although IIJA made limited changes to FPA Section 216(a)(1), DOE overly expanded the Study scope to include an analysis similar to a generation planning study, which SERTP Sponsors caution could cross over into state jurisdiction and result in inaccurate and unactionable transmission need determinations. SERTP Sponsors notify DOE that if the final Study and NIETC designation is based on the analyses presented in the draft Study, then the Department will be required to address these statutory concerns.

SERTP Sponsors also argue that FPA Section 216(a) includes certain considerations in designating a NIETC, including core economic concerns that necessitate an analysis of cost, which SERTP Sponsors imply the Needs Study omits, and therefore is unsuitable to utilize in corridor designations.

Similarly, Keryn Newman declares that DOE has not sufficiently answered the question of its authority and jurisdiction to plan the transmission system, which Newman argues is outside DOE's jurisdiction. Newman claims that DOE also does not have authority over cost allocation, arguing that transmission planning and cost allocation fall under the responsibilities of existing planning authorities. Newman elaborates that DOE's authority is restricted to the designation of corridors that shift transmission permitting from states to federal regulators.

ACC stresses that DOE should acknowledge in the Study that its principal aim is to carry out its "Congressionally delegated authority and expertise" rather than "shoehorn ancillary Administration policy goals into federal actions that are neither designed for nor compatible with a kitchen sink policy strategy."

Lastly, the NCUC reference pages 1–2 of the draft Study, stating that the listed benefits of mitigating transmission needs overstep the specific considerations for NIETCs set out in the FPA.

Department Response

In response to comments seeking clarity on the NIETC designation process, the Department has included additional context in *Section I. Introduction* of the final Study to clarify the Study's relationship with the Department's NIETC designation process (pages 1–2). See the Department Response in Section 1.4 above for additional discussion. Further, the Department has provided its statutory authority for the Needs Study and NIETC designation in *Section II. Legislative Language* (pages 6–7).

5.3. Designation of National Interest Electric Transmission Corridors

Many commenters provided feedback related to the designation of NIETCs. In general, comments relate to engagement with stakeholders or coordinating with other entities, requests for additional clarification on how the Needs Study will inform NIETC designation, and support or challenges to DOE statutory authority to NIETC designation.

Stakeholder Engagement and Coordination

Several commenters, including PJM, the Center for Biological Diversity, EDF, CEBA, and others recommend that DOE thoroughly engage with states, affected parties, industry, or other stakeholders throughout the NIETC designation process. The Center for Biological Diversity urges DOE to engage in meaningful dialogue with stakeholders before designating corridors. While it recognizes the administration's rush to build out transmission infrastructure, the Center emphasizes that meaningful community engagement and trust are crucial to effective implementation of this effort. Specifically, it encourages DOE to include trusted leaders and community-based organizations who are appropriately compensated for their work, while prioritizing those who have proven history of positive community engagement.[71] Furthermore, the Center for Biological Diversity encourages DOE to address barriers to engagement by holding meetings at times and places that maximize community turnout and provide childcare, translation services, and the option to attend virtually.[72] EDF also encourages DOE to consult

[71] California Energy Commission. Disadvantaged Communities Advisory Group, Equity Framework. Available at https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/infrastructure/disadvantaged-communities/dacag-equity-framework.pdf?sc_lang=en&hash=130F6FD0AEA89095CD0EAC455D0C60EE.

[72] See Initiative for Energy Justice, The Energy Justice Workbook, Section 1 – Defining Energy Justice: Connections to Environmental Justice, Climate Justice, and the Just Transition. Available at https://iejusa.org/section-1-defining-energy-justice/.

with potentially affected communities, nongovernmental organizations with expertise in transmission capacity and congestion, affected states, Indian Tribes and other relevant voices in considering NIETC designations. Similarly, DCC recommends that DOE provide additional transparency and opportunities for stakeholder and public input on the NIETC designation process, particularly ones that include large commercial and industrial customers.

Although Con Edison notes that a NIETC may not currently be needed in New York, Con Edison is supportive of DOE using Needs Study findings to encourage discussions between regions. Con Edison also urges DOE to engage with state public service commissions and stakeholders to review potential recommendations. To ensure the Needs Study and any NIETC designations are based on the best available information, SERTP Sponsors suggest that DOE coordinate with transmission planners and planning coordinators, such as the NERC-registered planning coordinators, as these entities include state load, resource projections, and cost evaluations in their transmission planning.

Clarification on Use of the Needs Study in Informing NIETC Designation

AEU, CEBA, ACP, EEI, ACEG, PJM, and PIOs urge DOE to provide more information on how the conclusions of the Needs Study will be used to evaluate the designation of NIETCs going forward. PJM is concerned that the Study does not provide guidance on the size of the area that might be considered to address the identified capacity constraints or congestion, which makes it difficult to determine how future NIETC designations will be based on specific conclusions in the Needs Study.

EEI notes that in DOE's Building a Better Grid Initiative NOI, DOE "indicated that it intends 'to provide a process for the designation of National Corridors on a route-specific, applicant-driven basis,' with the intent of facilitating efficient consideration of projects seeking a FERC-issued permit." EEI recommends that DOE elaborate on how applicants can utilize the Needs Study in their applications (e.g., explaining when and how a project/NIETC application will be evaluated in terms of meeting customers' needs and cost-effectiveness).[73]

DOE Statutory Authority to NIETC Designation

EDF, PIOs, DCC, and others acknowledge DOE's authority to designate NIETCs based on needs identified in the draft Study. EDF and PIOs emphasize that DOE is well within its authority to consider both historical and future needs of the system. Specifically, EDF supports DOE's definition of transmission capacity constraints, stating that the definition "aligns with the Department's role in preparing a study designed to identify NIETCs as well as in administering research and development, loan, and grant programs supporting transmission build-out and other electric system improvements." PIOs further elaborate that Section 216(a)(4) outlines several factors that can be considered in corridor designation, including national energy policy and security interests, economic growth, and diversification of resources.

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[73] U.S. Department of Energy. 2022. Building a Better Grid Initiative to Upgrade and Expand the Nation's Electric Transmission Grid to Support Resilience, Reliability, and Decarbonization on [p. 16]. Available at https://www.energy.gov/sites/default/files/2022-01/Transmission%20NOI%20final%20for%20web_1.pdf.

However, a few commenters express concern over using the Needs Study to inform NIETC designation. SERTP Sponsors state that because the Needs Study does not consider costs, the Study is not an appropriate basis for NIETC designation, which should also consider costs. SERTP Sponsors urge DOE to coordinate with planning entities as they perform analyses that evaluate state load and resource projections, as well as costs.

Similarly, PJM believes that because the Needs Study does not elaborate on the details of how a geographic corridor could alleviate congestion identified in the Study and what could constitute an appropriate corridor, the draft Study cannot provide a framework for NIETC designation and could lead to legal challenges questioning whether corridor designations are "arbitrary and capricious."

Other

Additionally, CEBA encourages DOE to ensure NIETC designation efforts are consistent with FERC reforms on transmission planning and backstop siting so that transmission planning and siting processes are coordinated and do not delay transmission development further.

PSEG reminds DOE not to overlook regions with significant OSW targets—such as the Mid-Atlantic—as the Needs Study informs the designation of corridors.

Department Response

The Department notes that while it certainly intends to engage with states, affected parties, industry, or other stakeholders throughout the NIETC designation process, it has determined further discussion of in-depth NIETC processes falls beyond the scope of this Study. As noted above, the Department has included additional context in *Section I. Introduction* of the final Study to clarify the Study's relationship with the Department's NIETC designation process (pages 1–2). See the Department Response in Section 1.4 above for additional discussion.

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