National Transmission Planning Study

Executive Summary

NREL

Pacific Northwest National Laboratory

GDO Grid Deployment Office

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Context

The National Transmission Planning Study (NTP Study) is presented as a collection of six chapters and an executive summary, each of which is listed next. The NTP Study was led by the U.S. Department of Energy's Grid Deployment Office, in partnership with the National Renewable Energy Laboratory and Pacific Northwest National Laboratory.

- The **Executive Summary (this chapter)** describes the high-level findings from across all six chapters and next steps for how to build on the analysis.
- **Chapter 1: Introduction** provides background and context about the technical design of the study and modeling framework, introduces the scenario framework, and acknowledges those who contributed to the study.
- **Chapter 2: Long-Term U.S. Transmission Planning Scenarios** discusses the methods for capacity expansion and resource adequacy, key findings from the scenario analysis and economic analysis, and High Opportunity Transmission interface analysis.
- **Chapter 3: Transmission Portfolios and Operations for 2035 Scenarios** summarizes the methods for translating zonal scenarios to nodal-network-level models, network transmission plans for a subset of the scenarios, and key findings from transmission planning and production cost modeling for the contiguous United States.
- **Chapter 4: AC Power Flow Analysis for 2035 Scenarios** identifies the methods for translating from zonal and nodal production cost models to alternating current (AC) power flow models and describes contingency analysis for a subset of scenarios.
- **Chapter 5: Stress Analysis for 2035 Scenarios** outlines how the future transmission expansions perform under stress tests.
- **Chapter 6: Conclusions** describes the high-level findings and study limitations across the six chapters.

As of publication, there are three additional reports under the NTP Study umbrella that explore related topics, each of which is listed next.[1] For more information on the NTP Study, visit https://www.energy.gov/gdo/national-transmission-planning-study.

- **Interregional Renewable Energy Zones** connects the NTP Study scenarios to ground-level regulatory and financial decision making—specifically focusing on the potential of interregional renewable energy zones.

[1] In addition to these three reports, the DOE and laboratories are exploring future analyses of the challenges within the existing interregional planning landscape and potential regulatory and industry solutions.

- **Barriers and Opportunities To Realize the System Value of Interregional Transmission** examines issues that prevent existing transmission facilities from delivering maximum potential value and offers a suite of options that power system stakeholders can pursue to overcome those challenges between nonmarket or a mix of market and nonmarket areas and between market areas.
- **Western Interconnection Baseline Study** uses production cost modeling to compare a 2030 industry planning case of the Western Interconnection to a high renewables case with additional planned future transmission projects based on best available data.

List of Acronyms

AC	alternating current
B2B	back-to-back
CO_2	carbon dioxide
DOE	U.S. Department of Energy
FERC	Federal Energy Regulatory Commission
GDO	Grid Deployment Office
GW	gigawatt
GWh	gigawatt-hour
HOT	High Opportunity Transmission
HVDC	high-voltage direct current
kV	kilovolt
LCC	line-commutated converter
MISO	Midcontinent Independent System Operator
MT	multiterminal
MW	megawatt
MWh	megawatt-hour
NPV	net present value
NREL	National Renewable Energy Laboratory
NTP Study	National Transmission Planning Study
P2P	point-to-point
PNNL	Pacific Northwest National Laboratory
PNW	Pacific Northwest region of the United States
ppm	parts per million
SPP	Southwest Power Pool

TRC	technical review committee
VRE	variable renewable energy

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Study Findings

To understand the transformation needed to ensure the U.S. electric transmission system continues to reliably serve the nation's electricity customers as the power sector evolves and transitions to cleaner resources, the U.S. Department of Energy (DOE) Grid Deployment Office (GDO) partnered with the National Renewable Energy Laboratory (NREL) and the Pacific Northwest National Laboratory (PNNL) on the multiyear **National Transmission Planning Study (NTP Study)**. The study sought to:

- Develop new national-grid-scale planning tools and methods that can be used by industry, especially when planning for interregional transmission capacity needs
- Identify potential transmission solutions that will provide broad-scale benefits to electric customers under a wide range of potential futures
- Inform planning processes for regional and interregional transmission
- Identify interregional and national strategies to maintain grid reliability as the grid transitions, including to a reliance on low- and zero-carbon energy resources.

The interregional focus of the NTP Study helps fill a gap in transmission planning—which, by design, focuses on the regional needs within each regional transmission planning entity's boundaries—as performed by industry today. As DOE explained in the 2023 National Transmission Needs Study, additional investments in interregional transmission will support system reliability and lower overall consumer costs. Extreme events that cause power plant outages—such as hurricanes and winter storms—or large spikes in electricity demand—such as high air conditioning use during heat waves—are increasingly common, and their impacts on the power system can be widespread. Mismatch in generation and demand from extreme events can result in temporary power outages and high prices for consumers. When one portion of the system experiences generation shortfalls, another portion of the grid is likely to have excess generation capacity that can support those shortfalls—if there is sufficient interregional transmission to deliver that excess capacity to the area of need. Interregional transmission also supports the development of within-region transmission, which must be reinforced to reduce congestion and reliably deliver generated electricity across long distances.

The NTP Study combined innovative methods with state-of-the-art industry practices demonstrating a forward-thinking approach to understanding the role and value of transmission in future power systems. The national perspective of the study, which incorporates systemwide optimization, enables a holistic examination of transmission, assuming regulatory and institutional barriers are overcome. The study used a combination of tools—all under the principles of least-cost planning and maintaining power system reliability—to analyze multiple facets of transformative transmission expansion for the power system in the contiguous United States. External engagement with industry convener groups, a technical review committee (TRC), Tribes, and the public provided valuable input throughout the study. The study's principal findings with related key takeaways are listed next.

Under current policies…

The lowest-cost U.S. electricity system portfolios that meet future demand growth and reliability requirements include substantial expansion in transmission.

- The total transmission system of the contiguous United States expands to 2.1 to 2.6 times the size of the 2020 system by 2050 and interregional transmission grows 1.9 to 3.5 times.
- Interregional coordination to meet resource adequacy, using both existing and new transmission, can save the U.S. electricity system hundreds of billions of dollars.
- Accelerating transmission deployment beyond historical rates reduces power system CO_2 emissions by 10 to 11 billion metric tons (43% to 48%) through 2050.
- The amount of transmission expansion and the emissions savings from transmission scale with the level of electricity demand.

Under a U.S. electricity system carbon target that achieves a 90% greenhouse gas emissions reduction by 2035 and 100% by 2050…

The study finds hundreds of billions of dollars of net benefits from large-scale transmission expansion compared to historic rates of transmission deployment.

- Accelerated transmission expansion leads to national electricity system cost savings of $270–490 billion through 2050.
- Incremental investments in transmission are more than compensated for by reduced electricity system costs for fuel, generation and storage capacity, and other costs. Approximately $1.60 to $1.80 is saved for every dollar spent on transmission.
- The benefits of transmission expansion to system costs scale with the level of electricity demand and rate of decarbonization.

A substantial expansion of the transmission system throughout the entire contiguous United States delivers the largest benefits across a wide variety of scenarios.

- The United States transmission system expands to 2.4 to 3.5 times the size of the 2020 system by 2050.

- Transmission expansion occurs at all scales—including local, regional, and interregional—and for all regions of the country. Expansion of new long-distance transmission is concentrated in the central part of the country.

- The use of high-voltage direct current (HVDC) transmission technologies, including advanced multiterminal converters, results in the greatest benefits to consumers across the transmission options studied.

- The largest benefits of transmission are realized when interregional transmission is most substantial, including when transmission is built across the interconnection seams. When U.S. electricity emissions are limited, future transfer capacities for many regions exceed 30% of the region's peak demand and total aggregate U.S. interregional transfer capacity increases to 2.6 to 4.6 times the 2020 capacity by 2050.

- Constraining transmission growth results in higher cost portfolios with more nuclear generation, hydrogen, and carbon capture capacity required especially when carbon emissions are limited.

Grid reliability can be maintained in future low-carbon grid scenarios with the lowest-cost solutions relying on coordinated transmission utilization between regions during periods of greatest stress.

- All 96 modeled future grid scenarios in the study—including those with approximately 90% of annual generation from variable resources—meet or exceed resource adequacy standards.

- When transmission regions coordinate to achieve resource adequacy, system costs through 2050 are lowered by $170–380 billion. In scenarios that allow coordination, transmission is used bidirectionally across many regional interfaces to support resource adequacy.

- High-resolution grid simulations demonstrate hourly demand and supply can be balanced in power systems with very high shares of renewable energy. In scenarios with larger transmission expansion, imports and exports between regions play a substantial role in helping grid operators balance supply and demand in all hours.

- Power flow analyses specific to the Western Interconnection demonstrate highly decarbonized systems can withstand selected typical contingencies on new-build transmission lines even when lines are highly loaded. Energy storage provides a substantial portion of the primary frequency response for the modeled large power plant contingencies.

- An analysis of four extreme event stress cases in the Western Interconnection showed in some cases the buildout of additional interregional transmission can support the power system during extreme weather events, decreasing the potential for and amounts of power shortages.

The NTP Study identifies several examples of transmission investment that could be promising candidates for more in-depth consideration by planners and developers.

- High Opportunity Transmission (HOT) interfaces represent transmission capacity expansion results between regions across many scenarios. Transmission projects that align with these HOT interfaces could be strong candidates for further study and serve as a starting point for accelerated transmission expansion.

- Transmission portfolios that deliver broad-scale benefits to consumers were developed using laboratory and industry tools. These transmission portfolios demonstrate new interregional transmission combined with intraregional transmission upgrades can help meet the flexibility requirements of high renewable energy power systems.

<u>Regardless of future policy, market, and technology conditions…</u>

Grid planning at the national or multiregional scale requires enhanced institutional coordination, accessible data, and new grid modeling approaches, which have advanced under the NTP Study in partnership with technical and planning experts.

- Advancing grid models—merging siloed planning processes, facilitating translations between models, and overcoming computational barriers—is critical to analyzing transmission comprehensively and capturing transmission's multifaceted impacts.

- Additional data on potential extreme events, technology advancements, and demand uncertainty will support robust transmission and reliability planning to identify the best expansion opportunities for consumers under changing conditions. Data access enables broader participation and collaboration.

- The identified benefits and expansion opportunities assume coordinated planning and use of transmission that goes beyond current practices. Developing guidelines for planners or a framework for coordination between numerous stakeholders can help realize these benefits.

Introduction and Context

The NTP Study is a novel approach to national-scale, interregional transmission planning and carries with it significant insights for future transmission planning in the United States. The NTP Study links several long- and short-term power systems models to test numerous interregional and regional transmission buildout scenarios. These modeled scenarios and the resulting analyses test transmission options that are typically not considered in current planning practices and are coupled with a wide range of economic, reliability, and resilience indicators. The findings of the NTP Study will inform existing planning processes and have already contributed to additional development of transmission planning research and toolkits.

The U.S. transmission network is the backbone of the electricity system, serving 160 million customers as of 2022 and delivering highly reliable, affordable electricity that ensures the lights stay on and businesses operate, even during periods of extreme demand. Though the transmission system has served U.S. energy needs for more than a century, the country's needs are changing.

To meet the growing demand for electricity, improve electric service reliability and resilience, reduce consumer costs, and enable access to low-cost generation during both normal and emergency operations, there is growing recognition that additional interregional transmission capability and connectivity is necessary. However, existing grid planning efforts are fragmented and focused on identifying local and regional solutions. Current planning processes rarely consider whether interregional solutions could meet these needs more efficiently or effectively. Moreover, existing planning tools may not capture the value that interregional solutions can provide as the grid evolves in response to the rapid growth of advanced clean energy technologies, changing demand patterns driven by electrification and emerging industries, and the increased frequency of extreme weather events.

Though transmission owners and operators are investing in transmission system maintenance and upgrades, the rate of new transmission capacity added to the U.S. grid over the past decade is dramatically lower than in previous historical periods. In contrast, generation and storage capacity additions are steadily increasing. Over the past 5 years (2019–2023), nearly 200 gigawatts (GW) of new capacity has been added, about 80% of which is from clean electricity sources (wind, solar, storage, and nuclear) (EIA 2024). Continued interest in clean energy development is expected with more than 1,480 GW of solar and wind and 1,030 GW of storage seeking interconnection to the grid throughout the United States as of 2024 (LBNL 2024). Expanded transmission could enable additional opportunities for connecting and distributing already proposed generation projects, balance the variability of wind and solar resources, and accommodate growing energy demands while maintaining system reliability and energy affordability. An expanded transmission system will help meet national energy objectives—supporting domestic manufacturing, enabling increasingly energy-intensive computing, and electrifying large parts of the economy—and continue to serve the evolving energy needs of the next century.

These demands and opportunities are why, in 2022, GDO launched the NTP Study, a multiyear effort involving GDO and two national laboratories—National Renewable Energy Laboratory (NREL) and Pacific Northwest National Laboratory (PNNL)—to understand the scope of interregional transmission needs and develop the national grid-scale planning tools and practices necessary to address these needs. The study team—comprising GDO staff and national laboratory (NREL and PNNL) researchers—has produced analyses and tools that have led to the development of additional interregional planning studies, reports, and papers. Together, the NTP Study and its companion reports seek to establish a foundation to identify and pursue interregional transmission solutions needed to meet national imperatives to enhance reliability, improve resilience to extreme weather and other disasters, and reduce consumer costs as the grid transitions to a decarbonized future.

External Engagement

The NTP Study's external engagement efforts leveraged the expertise of a broad set of power system experts and interested parties around the country and provided opportunities for the study team to receive feedback on study assumptions, methods, and objectives. External engagement included the following four components:

- **Public** engagement through public meetings and an online comment form
- Engagement with **existing convener groups** such as the Eastern Interconnection Planning Collaborative and Western Electricity Coordinating Council
- A laboratory-led **Technical Review Committee (TRC)** inclusive of three subcommittees: a Modeling Subcommittee, a Government Subcommittee, and an Environmental Exclusion and Land Use Subcommittee
- **Tribal** outreach that included broad outreach to Tribes in the United States with assistance from DOE's Office of Indian Energy and targeted follow-up with interested Tribes.

During the project, DOE conducted 3 virtual public meetings, and the laboratory team conducted 18 virtual meetings with various subsets of the TRC, which included presenting interim results and gathering stakeholder feedback. More details on these meetings are presented in Chapter 1. In addition, TRC members individually provided feedback about scope and assumptions, shared modeling details about their regions, and helped clarify messaging regarding modeling results to be relevant for industry.

Study Approach and Scenarios

The U.S. transmission system has a variety of technical challenges, many unique to each of the thousands of involved utilities, plus expansive geography with regional diversity in resources and planning outlooks. The transmission system is large and complex enough that modeling the true physics of the system at a fine level of detail over time pushes the limits of current computational capacity. To capture this complexity, the study team used several interlinked models—including translating results from zonal models down to nodal resolution—to enable expansive insights about the future of the U.S. electricity system with the level of detail needed for rigorous transmission planning (Figure ES-1). The two key principles behind the study design are least-cost planning (i.e., planning for the lowest system cost portfolio from a broad array of options) and power system reliability (i.e., the ability of the power system to continually supply electricity). These principles are applied to a broad range of future power sector scenarios.

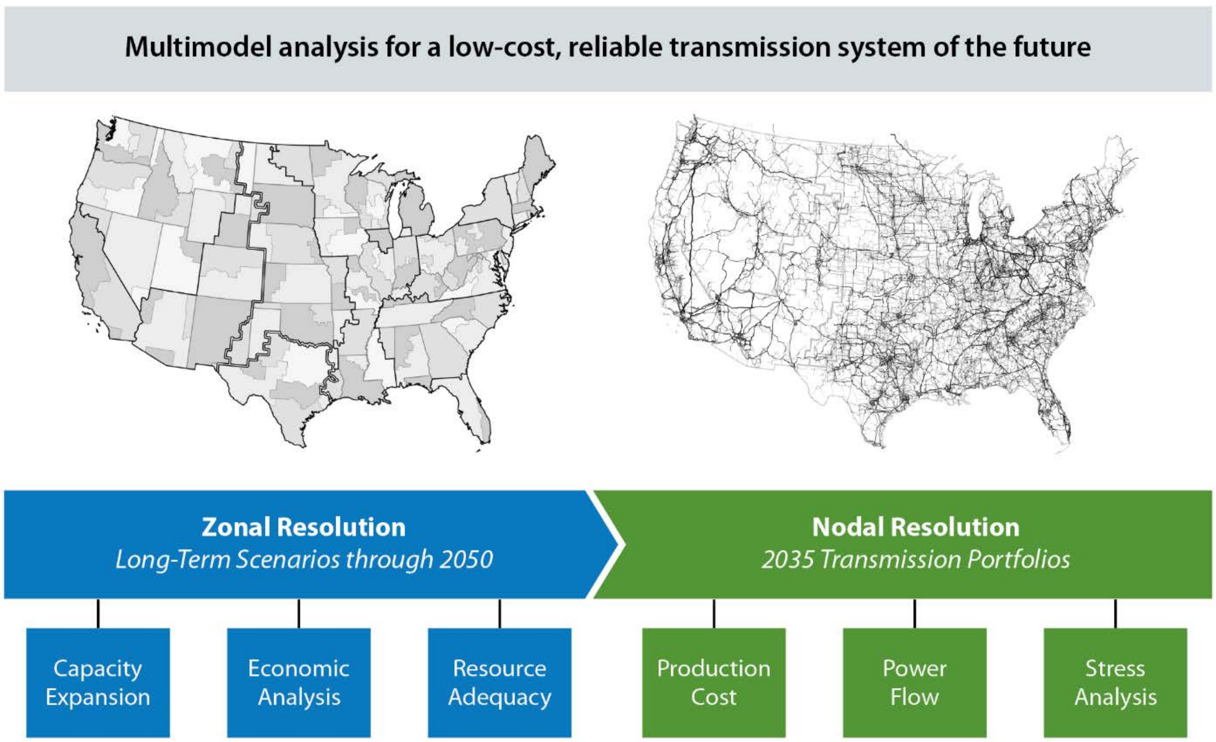

Figure ES-1. NTP Study approach

To analyze the future power system, the NTP Study first applies capacity expansion modeling and resource adequacy analyses of wide-ranging future electricity supply, demand, storage, and transmission needs for all regions across the contiguous United States. The study team analyzed numerous future scenarios through 2050 to examine uncertainties and identify robust regional and interregional transmission opportunities. The scenario analysis compared how the optimal electricity system—including generation, storage, and transmission—might evolve with different constraints and opportunities for transmission. The study team compared a "Limited" transmission framework, which constrains the annual rate of transmission expansion to the recent maximum rate and does not allow new interregional transmission builds, against three accelerated frameworks with increased options for transmission expansion (Figure ES-2). The comparison enabled isolation of the impacts of greater transmission expansion on power system costs, resource mixes, and emissions. Monetary cost and savings impacts are reported primarily for the U.S. electricity system as a whole with limited analysis on distributional impacts.

To better understand the challenges of applying transformative scenarios to detailed network models of the transmission system, the study team translated a subset of the scenarios into nodal representations of the system through a transmission planning phase. These nodal models—representing the entire contiguous U.S. transmission grid or the Western Interconnection in 2035, including scenario-specific transmission portfolios—were used to conduct production cost modeling and power flow analysis along with additional stress analysis. Conducting these analyses at the nodal resolution, consistent with industry practices, is necessary to further evaluate the engineering challenges of implementing transformative network topologies, operational differences between scenarios, and the reliability of the scenarios when integrating full network topologies and hourly operational constraints.

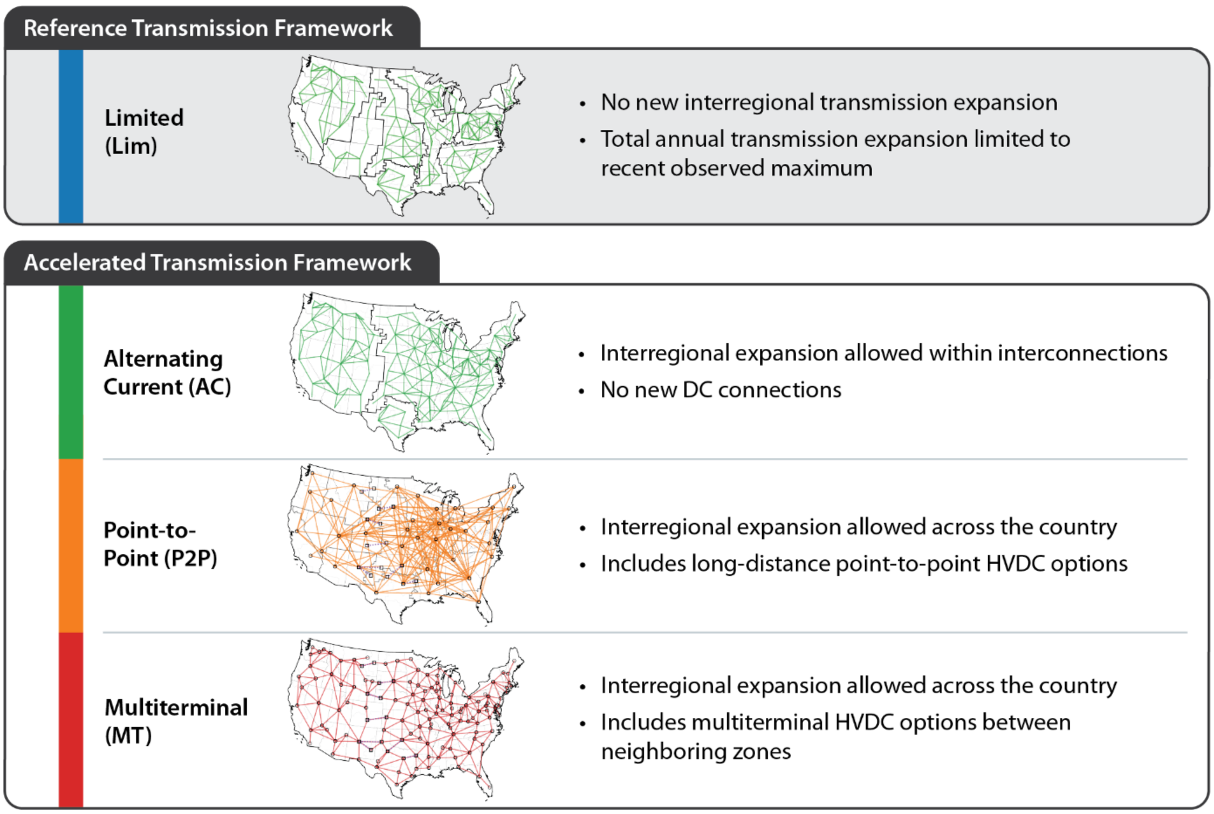

Figure ES-2. NTP Study transmission frameworks

Because the role and impact of transmission can vary based on many factors, the study team examined a wide range of demand growth and emissions reduction scenarios across the four transmission frameworks. The study includes current policy scenarios—which include state and federal policies enacted by June 2023, including the Inflation Reduction Act but excluding the final Clean Air Act section 111 standards—to examine how transmission development might impact future emissions. The study also includes scenarios with a limit on national annual emissions to achieve 90% power sector CO_2 emissions reductions (from 2005 levels) by 2035 and full grid decarbonization by 2045. The demand growth assumptions included a Low-Demand trajectory where U.S. load grows by 0.9% per year on a compound annual basis from 2021 to 2050 and Mid- and

High-Demand trajectories with greater load growth rates (2.0% per year and 2.7% per year, respectively) because of significant electrification projections. Under these latter two load growth cases, annual United States demand in 2050 is assumed to be 1.8–2.1 times demand in 2022, and demand peaks shift to winter periods in many regions. The analysis included multiple sensitivity cases to incorporate uncertainties with future transmission, generation, and storage costs; commercial availability of new low-emission options; renewable energy siting; impacts of climate change; and other factors. Altogether, the study team analyzed 96 scenarios. The study team made no judgment about the relative likelihood of different scenarios or assumptions; instead, the scenarios are used to evaluate the role of transmission under a wide range of possible future conditions.

Key Takeaways: Deep Dive

The following provides further insight into the benefits of transmission, the grid transformation needed to realize these benefits, the implications of expanded transmission on system reliability, and new approaches that could facilitate future national-scale or multiregional transmission planning. These insights are presented with six principal findings and several related key takeaways for each finding. The first principal finding relates to current policy conditions, the next four are based on analysis assuming an emissions target is met, and the last finding is applicable under diverse conditions.

Under current policies…

The lowest-cost U.S. electricity system portfolios that meet future demand growth and reliability requirements include substantial transmission expansion.

The total transmission system of the contiguous United States expands to 2.1 to 2.6 times the size the 2020 system by 2050 and interregional transmission grows 1.9 to 3.5 times. Figure ES-3 (left) shows total transmission capacity for all transmission frameworks under current policies. Transmission expansion found in the accelerated transmission expansion frameworks (alternating current [AC], point-to-point [P2P], and multiterminal [MT]) occurs to meet increasing electricity demand (2.0%/year under Mid-Demand) by enabling access to low-cost resources within regions and supports resource sharing between regions. The significant amount of transmission expansion is found to be cost-effective even in the absence of new emissions reductions policies. (Chapter 2)

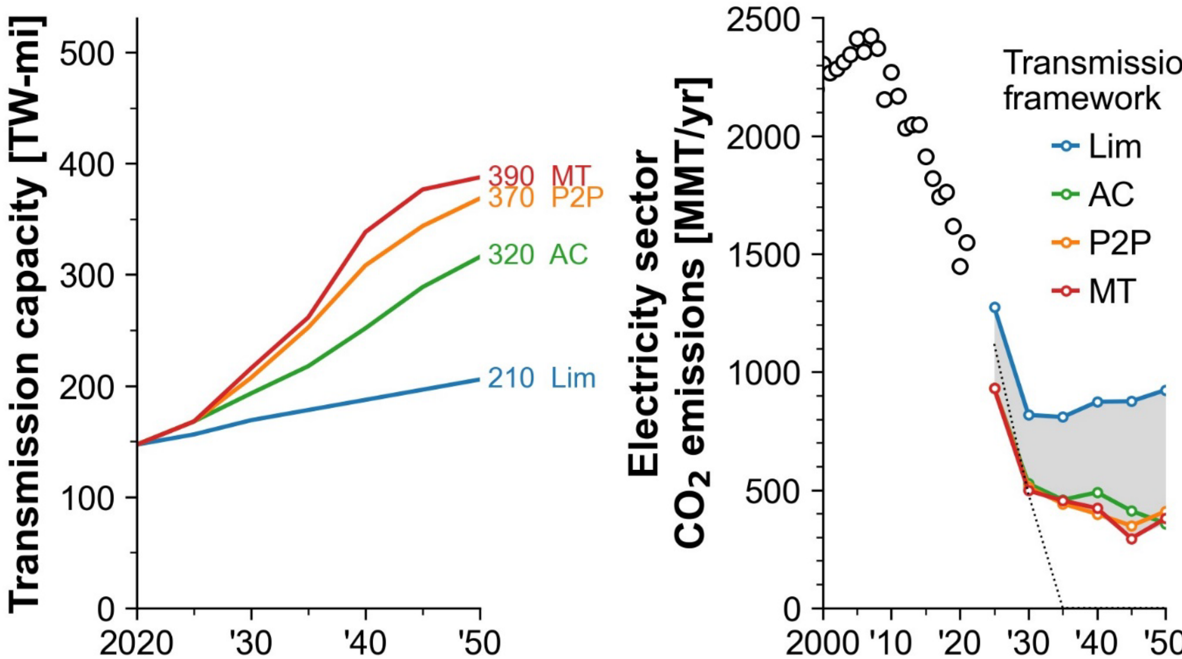

Figure ES-3. (Left) Total transmission expansion through 2050 and (right) annual national electric sector carbon dioxide emissions under current policies and Mid-Demand assumptions

Interregional coordination to meet resource adequacy, using both existing and new transmission, can save the U.S. electricity system hundreds of billions of dollars. Interregional transmission—over spatial scales larger than weather systems—enables efficient resource sharing between regions and smooths out variations in renewable energy availability. Leveraging new and existing transmission capacity across planning regions reduces the costs of meeting resource adequacy requirements. Under current policies, electricity system costs are reduced by about $100–300 billion with interregional resource adequacy sharing. (Chapter 2)

Accelerating transmission deployment beyond historical rates reduces power system CO_2 emissions by 10 to 11 billion metric tons (43% to 48%) through 2050. The scenario analysis finds increasing transmission greatly reduces electricity sector carbon emissions under existing policies. However, even with increased transmission expansion and recent state and federal clean energy policies, the power sector does not fully decarbonize without new policies. Figure ES-3 (right) shows annual electric sector emissions for all four transmission frameworks under Mid-Demand assumptions and with current policies as of June 2023. Compared to the Limited scenario, there is a roughly 56%–61% reduction in annual 2050 emissions in the three accelerated transmission frameworks and, on a cumulative basis (2025–2050), about 10–11 billion metric tons of CO_2 are avoided. The emissions reduction in the accelerated frameworks is driven by reduced reliance on fossil-fuel-based generation and capacity through greater deployment of wind and solar. (Chapter 2)

The amount of transmission expansion and the emissions savings from transmission scale with the level of electricity demand. Under high demand growth (2.7%/year), total transmission expands to 2.5 to 3.3 times the 2020 system by 2050. On a relative basis, growth in interregional transmission expansion is even greater with high demand; interregional transmission capacity in 2050 is up to 3.9 times the 2020 capacity in the MT framework. One driver of transmission expansion is from the increasing value of using interregional transmission for resource adequacy. With current policies only, cumulative avoided CO_2 emissions increase to 14 to 16 billion metric tons with high demand growth and are less substantial (3 to 4 billion metric tons) with low demand. (Chapter 2)

<u>Under a U.S. electricity system carbon target that achieves a 90% greenhouse gas emissions reduction by 2035 and 100% by 2050…</u>

The study finds hundreds of billions of dollars of net benefits from large-scale transmission expansion compared to current transmission deployment.

Accelerated transmission expansion leads to national electricity system cost savings of $270 to $490 billion through 2050. Accelerating transmission expansion lowers costs for the contiguous U.S. electricity system in all low-carbon scenarios. Figure ES-4 shows total transmission expansion and system cost savings of accelerated transmission expansion frameworks compared to the Limited (Lim) framework in the central decarbonization scenarios (i.e., scenarios that achieve 90% emissions reductions by 2035 and 100% by 2045 with Mid-Demand growth). These savings account for net changes in all capital, operating, and fuel expenditures for generation, storage, and transmission from 2022 to 2050 on a present value basis. Through 2035, most savings are realized from avoided fuel costs, but in the longer time frame, savings are primarily achieved by a lesser need for capital investments. (Chapter 2)

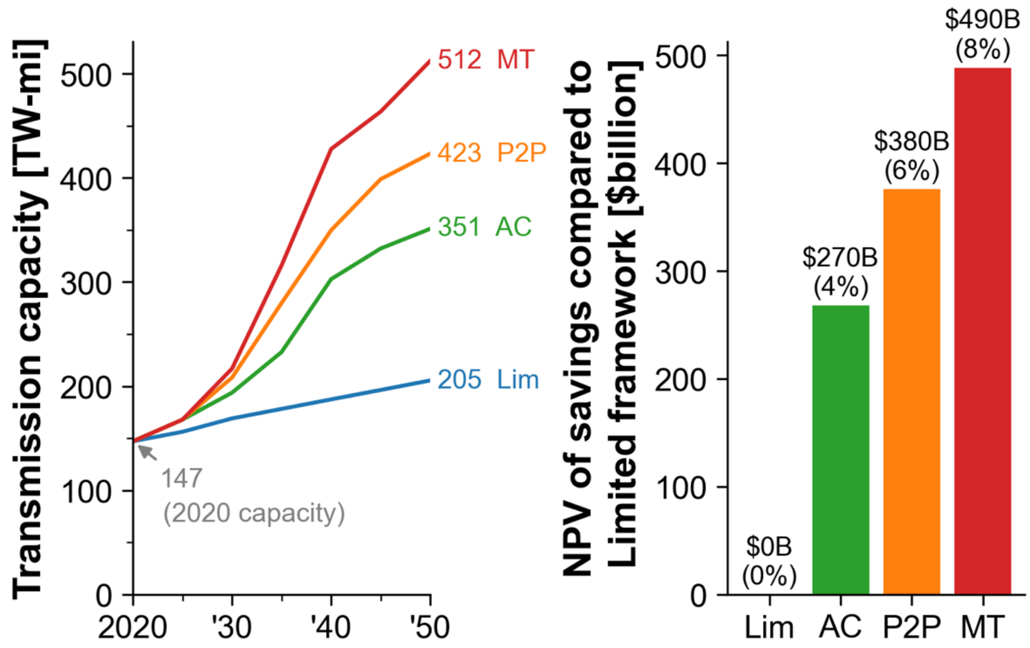

Figure ES-4. (Left) Total transmission expansion through 2050 and (right) cost savings of the accelerated transmission frameworks (AC, P2P, and MT) compared to the Limited framework with 90% by 2035 emissions reductions and Mid-Demand

Net present values (NPVs) include fixed and operating costs of generation, storage, and transmission and federal tax credits from 2022 through 2050, discounted using a 1.7% real discount rate (OMB 2023). The parentheses above the bars show the percent savings compared to the total system costs of the Limited framework.

Incremental investments in transmission are more than compensated for by reduced electricity system costs for fuel, generation and storage capacity, and other costs. Approximately $1.60 to $1.80 is saved for every dollar spent on transmission. In the core scenarios, the benefit-to-cost ratio is 1.6 for the AC framework, 1.7 for P2P, and 1.8 for MT. These cost savings are achieved by enabling greater access to low-cost generation resources and expanding opportunities for resource sharing for reliability. Across all sensitivities and accelerated transmission frameworks, electricity system savings occur in all or nearly all regions of the contiguous United States. (Chapter 2)

The benefits of transmission expansion to system costs scale with the level of electricity demand and rate of decarbonization. Under high demand growth, estimated net savings from accelerated transmission range from $710–970 billion and coupling high demand with more rapid decarbonization can yield more than $1 trillion in savings. Accelerated transmission deployment consistently reduces system cost across a spectrum of sensitivities with the greatest reductions found when hydrogen, carbon capture, and/or advanced nuclear power are unavailable. The economic benefits of transmission outweigh the incremental transmission costs in all scenarios, leading to a benefit-to-cost ratio of at least 1.5 across all sensitivity cases and exceeding 2.0 in many of them. (Chapter 2)

A substantial expansion of the transmission system throughout the entire contiguous United States delivers the largest benefits across a wide variety of scenarios.

The U.S. transmission system expands to 2.4 to 3.5 times the size of the 2020 system by 2050 in scenarios that achieve 90% emissions reductions by 2035 with lowest power sector costs. Figure ES-5 shows significant amounts of transmission are added to the grid to achieve 90% decarbonization of the electric sector in the contiguous United States by 2035 and 100% by 2045 while reliably meeting increasing demand. To achieve deep decarbonization, new transmission capacity rapidly scales and requires annual transmission installations multiple times the current development rate. With high demand growth, total U.S. transmission capacity in 2050 is 2.7–4.1 times the size of the 2020 grid. Many sensitivity cases result in even more extensive and rapid transmission expansion. (Chapter 2)

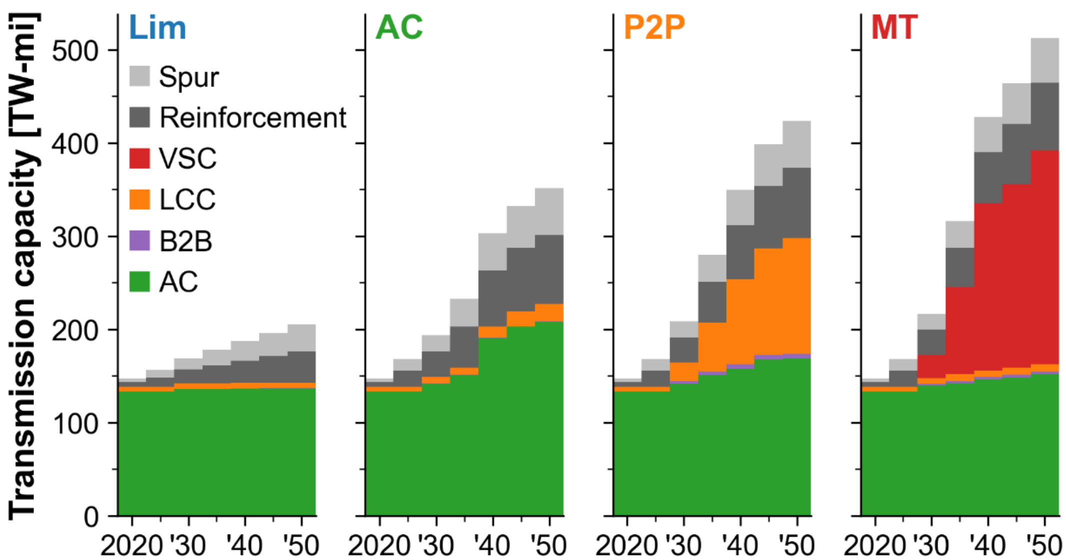

Figure ES-5. Total transmission capacity by type under Mid-Demand and 90% CO_2 reductions by 2035 assumptions for each transmission framework

Spur and reinforcement refer to local transmission needed for wind and solar interconnection. Voltage source converter (VSC) and line-commutated converters (LCC) refer to HVDC technologies assumed with the former allowed in the MT framework and the latter under the P2P framework (and for existing DC lines). Back-to-back (B2B) refers to ties between separate interconnections. All other interzonal transmission is assumed to use alternating current (AC) transmission.

Transmission expansion occurs at all scales—including local, regional, and interregional—and for all regions of the country. Expansion of new long-distance transmission is concentrated in the central part of the country. Local interconnection for new wind and solar (gray bars from Figure ES-5) is prioritized when transmission expansion is constrained (Limited framework), but both local and longer-distance transmission are installed under the least-cost portfolios without such constraints. With the accelerated transmission frameworks, new transmission infrastructure is installed throughout the contiguous United States, but long-distance transmission additions are particularly pronounced around the central wind belt. (Chapters 2, 3)

The use of high-voltage direct current (HVDC) transmission technologies, including advanced MT converters, results in the greatest benefits to consumers across the transmission options studied. For regional and interregional transmission, HVDC transmission additions outpace AC additions when allowed as shown for the P2P and MT frameworks from Figure ES-5. When translating zonal scenarios to nodal network models, HVDC was found useful for transferring power over long distances and between interconnections, but AC network expansion will continue to be the best solution for a large portion of transmission additions. Large interregional HVDC network solutions will also require additional strengthening of the regional AC networks they interconnect. (Chapters 2, 3)

The largest benefits of transmission are realized when interregional transmission is most substantial, including when transmission is built across the interconnection seams. When U.S. electricity emissions are limited, future transfer capacities for many regions exceed 30% of the region's peak demand and total aggregate U.S. interregional transfer capacity increases to 2.6 to 4.6 times the 2020 capacity by 2050. Figure ES-6 shows how interregional transmission—shown as the transfer capacity between the 11 planning regions—increases faster than peak demand growth for many regions in the accelerated transmission frameworks. With the assumed Mid-Demand load growth shown, the increase in *interregional* transfer capacity relative to 2020 is greater than the increase in *total* transmission estimated (2.6–4.6 times compared to 2.4–3.5 times). Interregional transfer capacities grow fastest for regions in the central part of the United States where future transfer capabilities are more than 100% of peak demand, especially with new HVDC options. When allowed, seam-crossing capacity expands significantly; more than ~40 GW of seam-crossing capacity is developed by 2035 across the three interconnection seams for the P2P and MT frameworks compared with about 2 GW today. (Chapters 2, 3)

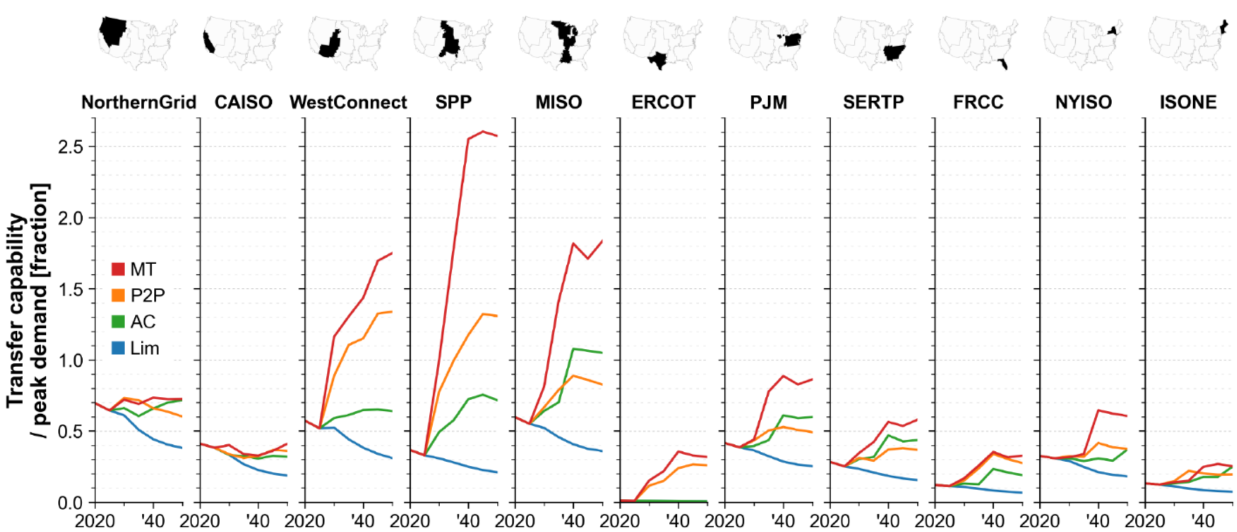

Figure ES-6. Ratio of interregional transfer capability to peak demand for the 11 planning regions with Mid-Demand 90% by 2035 assumptions across the four transmission frameworks

Constraining transmission growth results in higher-cost portfolios with more nuclear generation, hydrogen, and carbon capture capacity required especially when carbon emissions are limited. The economic benefits from transmission expansion result from increased access to the lowest-cost zero-carbon generation options: wind and solar. In the central decarbonization scenarios that achieve net zero emissions, combined wind and solar generation reaches about 80% of total generation by 2050, with hydropower and other renewable energy, nuclear, fossil carbon capture and sequestration, and hydrogen generation comprising the remainder. Generation shares of renewable energy in 2050 are about 20 percentage points lower in the Limited framework than in the other frameworks. Greater reliance on non-variable renewable energy (VRE) technologies when transmission (both local interconnection and longer-distance) is constrained results in higher system costs. (Chapter 2)

Grid reliability can be maintained in future low-carbon grid scenarios with the lowest-cost solutions relying on coordinated transmission utilization between regions during periods of greatest stress.

All 96 modeled future grids in the study—including those with approximately 90% of annual generation from variable resources—meet or exceed resource adequacy standards. Resource adequacy requirements ensure there are sufficient resources to meet demand considering expected availability and load uncertainties. Power systems are not planned for 100% reliability, but instead planning targets allow for a small amount of loss of load or demand that is not expected to be met. All systems modeled in the study are designed so the amount of unserved energy relative to total annual demand is less than 10 parts per million (ppm); this level of reliability is approximately equivalent to about 5 minutes per year of power disruptions for a typical customer. Using the central decarbonization assumptions and across all sensitivity cases and years, the median normalized expected unserved energy level is <1 ppm as estimated using 7 years of weather conditions. Current grid planners that use this resource adequacy metric apply a threshold ranging from 10 ppm to 30 ppm. (Chapter 2)

When transmission regions coordinate to achieve resource adequacy, system costs through 2050 are lowered by $170–380 billion. In scenarios that allow coordination, transmission is used bidirectionally across many regional interfaces to support resource adequacy. Coordinated planning to enable external resources to support local adequacy requirements increases the motivation for interregional transmission expansion. When resource adequacy requirements are met by in-region resources only, 40%–60% less interregional transmission capacity is added—resulting in the $170–380 billion higher systemwide costs. (Chapter 2, 3)

High-resolution grid simulations demonstrate hourly demand and supply can be balanced in power systems with very high shares of renewable energy. In scenarios with larger transmission expansion, imports and exports between regions play a substantial role in helping grid operators balance supply and demand in all hours. Interregional transmission provides significant opportunities and challenges for grid operators. In scenarios with more interregional transmission, the relative amount of demand that may be met by imports or the amount of power that will be exported from a region increases, highlighting coordination in planning and operations between regions may need to increase. Figure ES-7 shows the net interchange of power relative to demand from hourly production cost simulations for three power systems in 2035 that achieve 90% emissions reductions. Most regions rely on imports or exports in all three scenarios, but across almost all regions, the accelerated transmission scenarios lead to more overall energy exchange. More specifically, 19% of the total energy consumed in the Limited scenario flows over interregional transmission lines; that number increases to 28% in AC and 30% in the MT-HVDC scenario. In addition, most regions maintain their role as either primarily importers or primarily exporters across all three scenarios, but the amount of power being exported in the accelerated frameworks is often much greater than the load of a region (>1.0 in Figure ES-7) in Midcontinent Independent System Operator (MISO), Southwest Power Pool (SPP), and WestConnect. (Chapter 3)

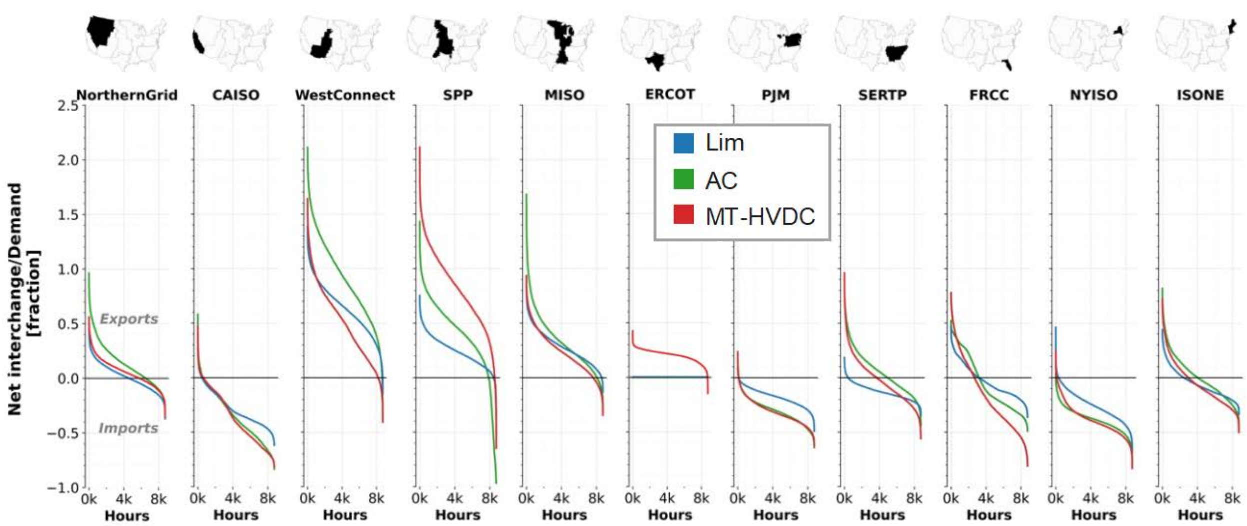

Figure ES-7. Ratio of net interchange to demand for the 11 planning regions across all hours in a year (ordered from highest to lowest) for Mid-Demand 90% emissions reductions by 2035 systems

Positive values indicate net exports and negative values indicate net imports. The MT-HVDC scenario refers to the nodal 2035 translation of the MT scenario, which encompasses characteristics of both HVDC scenarios from the zonal scenarios.

Power flow analyses specific to the Western Interconnection demonstrate highly decarbonized systems can withstand selected typical contingencies on new-build transmission lines even when lines are highly loaded. Energy storage provides a substantial portion of the primary frequency response for the modeled large power plant contingencies. Power flow analyses test whether voltages can remain within safe ranges even during major contingencies, such as individual transmission line or large generator outages. A power flow analysis of a future 90% decarbonized Western Interconnection that is generating 70% of energy from wind and solar demonstrates new transmission lines can help avoid voltage or thermal loading risks to the system, even when they are highly loaded. Figure ES-8 demonstrates no significant changes in voltage occur because of a modeled contingency. Voltages are stable in several scenarios and selected contingencies, including outages on new, large, highly loaded transmission lines. This is a preliminary indication of their robustness and indicates transmission portfolios modeled do not represent a significant risk to the system, even when highly loaded. Multiple resources help maintain stable voltages and frequencies in these transformative futures. Utility-scale energy storage provides a substantial portion of the primary frequency response for the modeled large power plant contingencies. (Chapter 4)

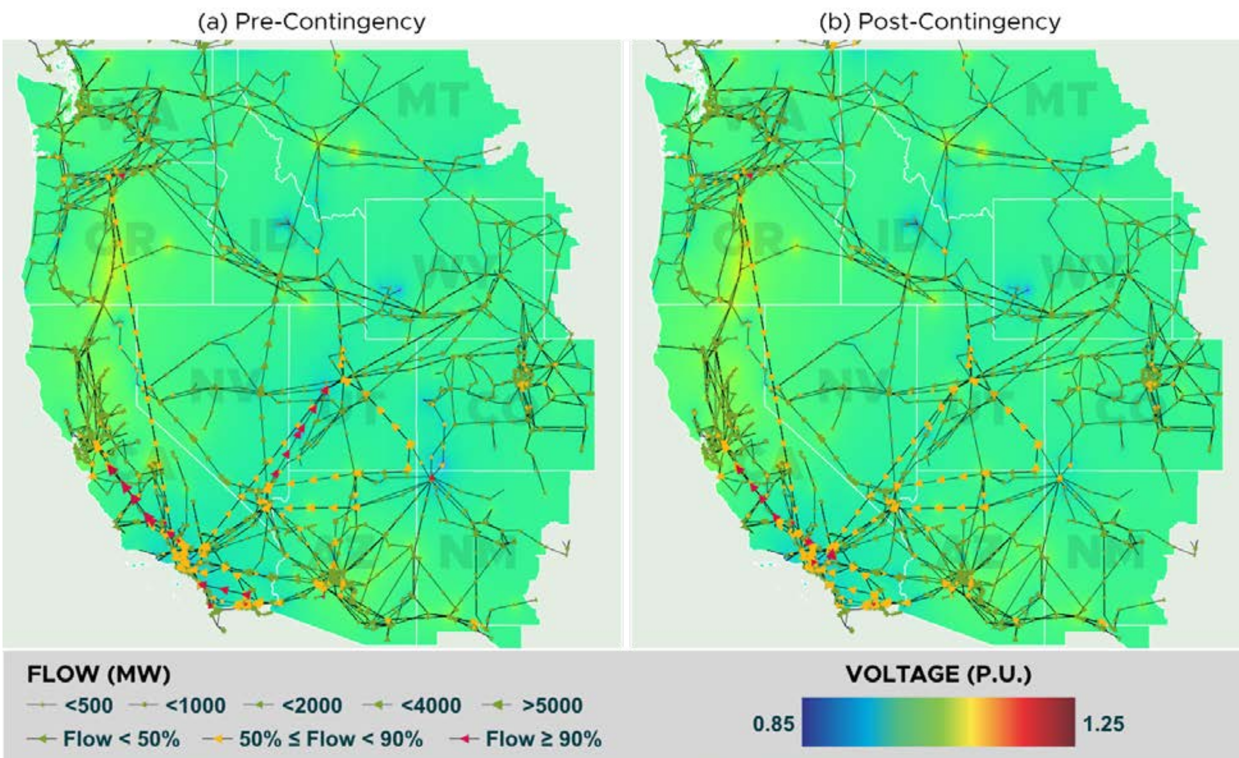

Figure ES-8. Voltage heatmaps (a) pre- and (b) post-contingency for the loss of 2600 megawatts (MW) of generation at a nuclear power plant for the AC scenario: No significant voltage changes following the contingency

Per-unit (P.U.) voltage is the actual (measured) voltage divided by the base voltage, or rating, of the transmission component.

The buildout of additional interregional transmission can support the power system during certain types of extreme weather events, decreasing the potential for and amounts of power shortages. More work is needed in this area. The study team conducted a stress analysis to evaluate the impacts of extreme events on future Western Interconnection power systems with greater and lesser transmission expansion. Extreme high-demand events considered included historic heatwaves (which are worsened to 2035 conditions to reflect the expectation of a warmer climate scenario) and drought conditions to project a potential reduction in hydropower generation. These events were also combined into a multi-event threat representing a co-occurrence of a drought (reduced hydropower) alongside a heatwave (increased energy demand) to test grid operations—including use of transmission—under compounded extreme conditions. Though these are not the only future stress cases that could occur, they serve as a proxy for understanding the system's response under stress.

To assess the role of transmission during extreme events, the study compares the Limited to the AC frameworks, as seen in Figure ES-9 and Figure ES-10. When a California or Pacific Northwest heatwave is combined with hydropower droughts in the Pacific Northwest, the unserved energy significantly increases for both regions. These increases are lower in the AC framework compared to the Limited framework in six of the eight scenarios considered, demonstrating how transmission could help improve reliability during high stress periods. For the remaining two scenarios, the study team observed lower amounts of unserved energy in California in the Limited framework compared to the AC framework. This is because the Limited framework has greater installed capacity of local dispatchable resources (such as battery storage and natural gas) that could support the state's increased load demands amid decreased generation imports from the Pacific Northwest. This result indicates transmission and resource planners should carefully consider interregional transmission capacity and all types of transmission, generation, and storage resources—including local assets—when minimizing the risks of extreme stress events.

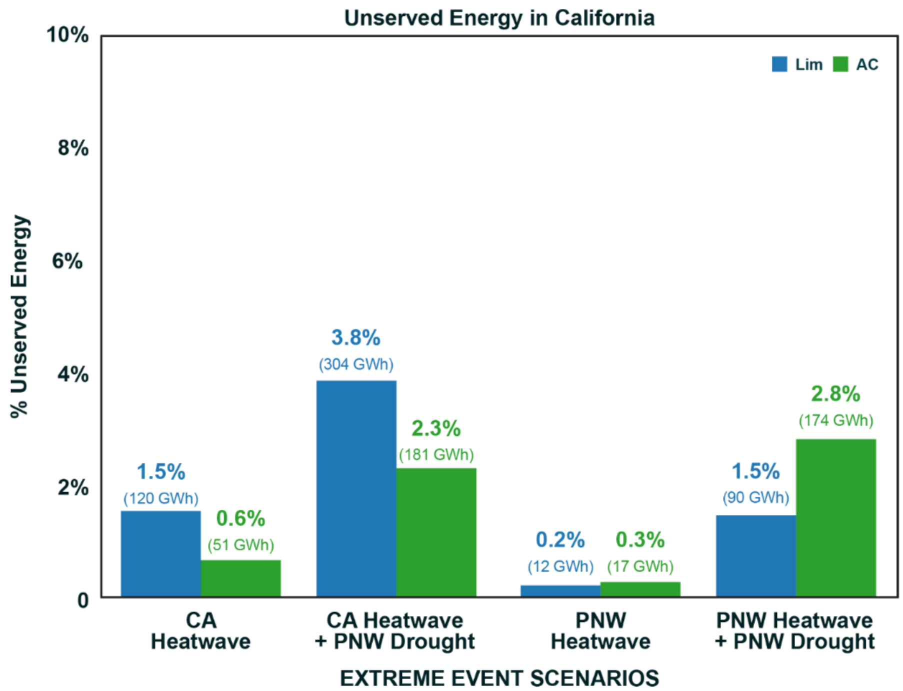

Figure ES-9. Projected unserved energy in California in response to singular and combined extreme events for the Limited and AC transmission frameworks

GWh = gigawatt-hours; CA = California; PNW = Pacific Northwest

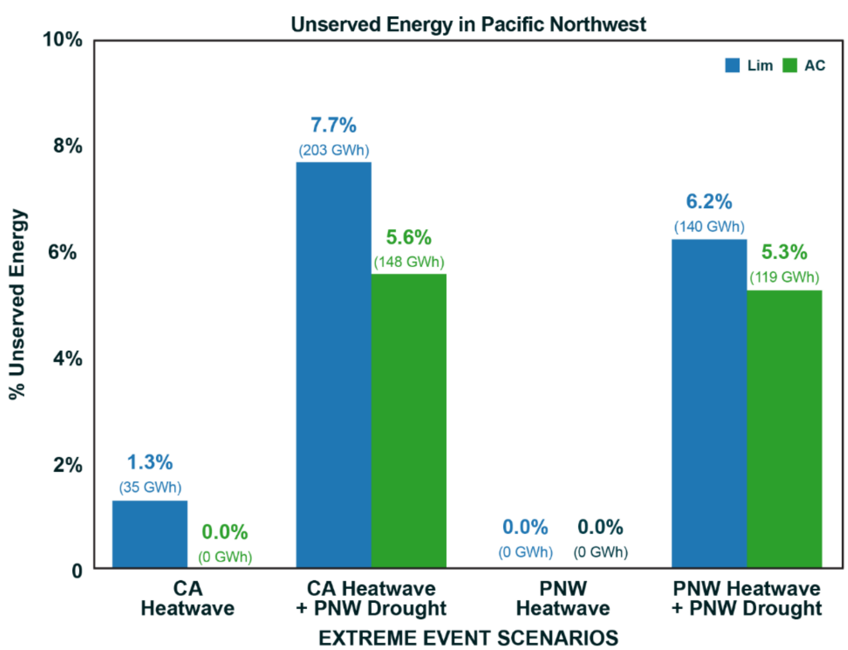

Figure ES-10. Projected unserved energy in the Pacific Northwest in response to singular and combined extreme events for the Limited and AC transmission frameworks

GWh = gigawatt-hours, CA = California, PNW = Pacific Northwest

The economic value of lost load for the unserved energy periods described here was in the tens to hundreds of billions of dollars for individual regions (i.e., the Pacific Northwest or California). However, to accurately assess the resilience benefits of interregional transmission, the probability of the extreme events must be incorporated into a full economic evaluation. Future work should include more types of extreme events across broader geographic areas. (Chapter 5)

The NTP Study identifies several examples of transmission that could be promising candidates for more in-depth consideration by planners and developers.

High Opportunity Transmission (HOT) interfaces represent transmission capacity expansion results between regions across many scenarios. Transmission projects that align with these HOT interfaces could be strong candidates for further study and serve as a starting point for accelerated transmission expansion. Spatial patterns of new transmission are similar across diverse conditions, and a systematic evaluation of interregional expansions can reveal HOT interfaces. Capacity for each HOT interface is defined as the expansion between subregions that occurs in 75% of the sensitivity cases (with 90% emissions reductions and Mid-Demand assumptions) by 2035. Figure ES-11 shows the HOT interfaces. (Chapter 2)

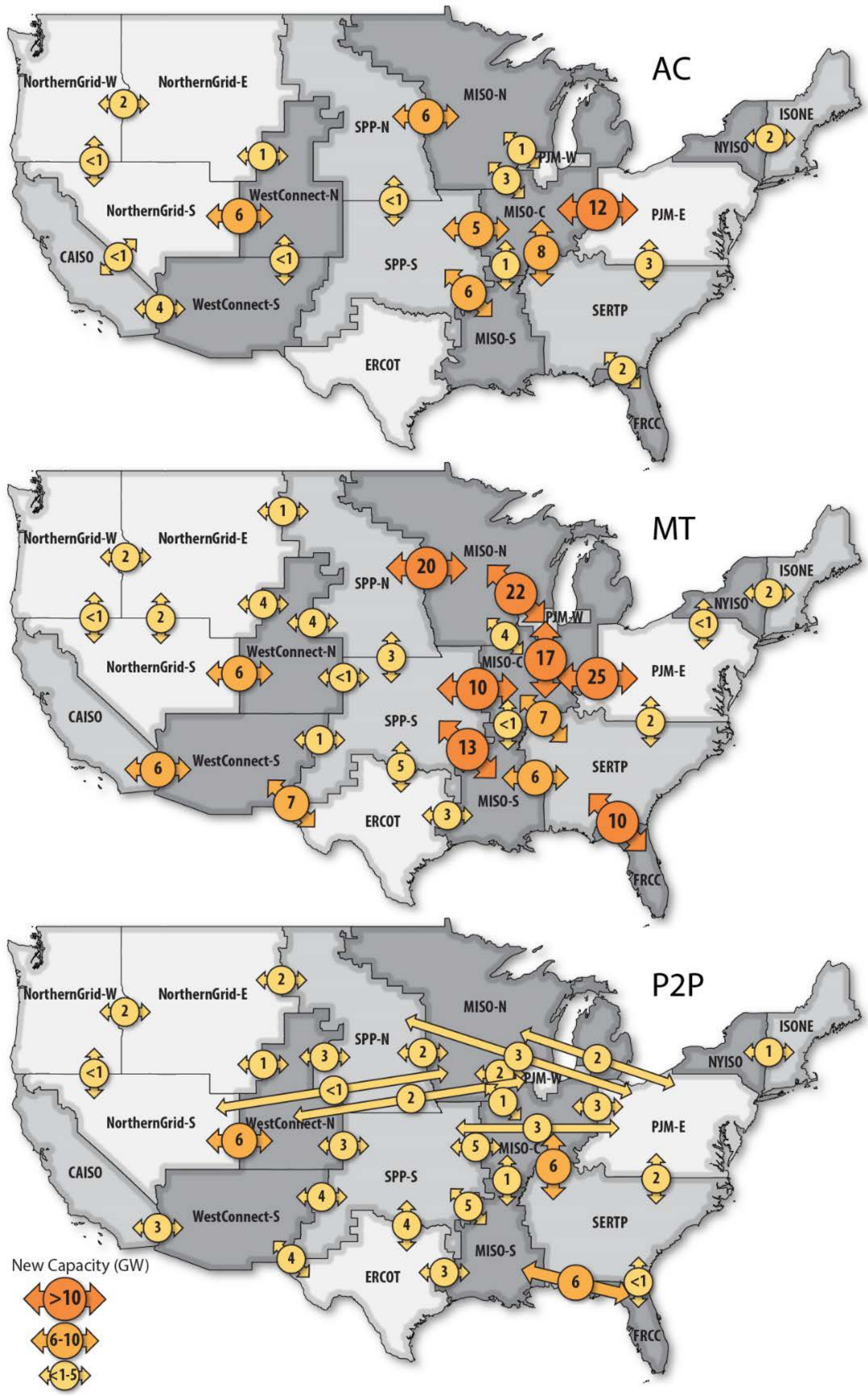

Figure ES-11. HOT interfaces for the 90% by 2035, Mid-Demand scenario, for the AC (top), MT (middle), and P2P (bottom) frameworks

Transmission portfolios that deliver broad-scale benefits to consumers were developed using laboratory and industry tools. These transmission portfolios demonstrate new interregional transmission combined with intraregional transmission upgrades can help meet the flexibility requirements of high renewable energy power systems. Translating zonal capacity expansion modeling results to nodal transmission portfolios is a key part of this study. Such a translation enables more detailed evaluations of the modeled scenarios, which establishes greater confidence in the operational reliability of the transformative future power grids envisioned. Figure ES-12 shows the transmission portfolio for the AC (top) and MT-HVDC (bottom) frameworks for 2035. The implementation of the AC scenario results in significant expansions of 345- and 500-kilovolt (kV) lines that help collect low-cost renewable energy in concentrated areas and deliver power over long distances. The MT-HVDC scenario uses MT HVDC for long-distance power transfers but still relies heavily on the expansion of the AC network to move power within and between regions. The MT-HVDC scenario also enables connections between the three interconnections, increasing the existing (as of 2023) amount of transfer capacity between the interconnections by greater than 20 times. The transmission portfolios from Figure ES-12 are only two specific illustrative implementations of the zonal HOT results. They provide a possible starting point for national or multiregional transmission planning that could deliver the cost, reliability, and emissions benefits found in the study. The transmission portfolios identified in this study can also be a starting point for states interested in exploring multistate and interregional transmission options. They do not represent proposed routes or other siting considerations. (Chapter 3)

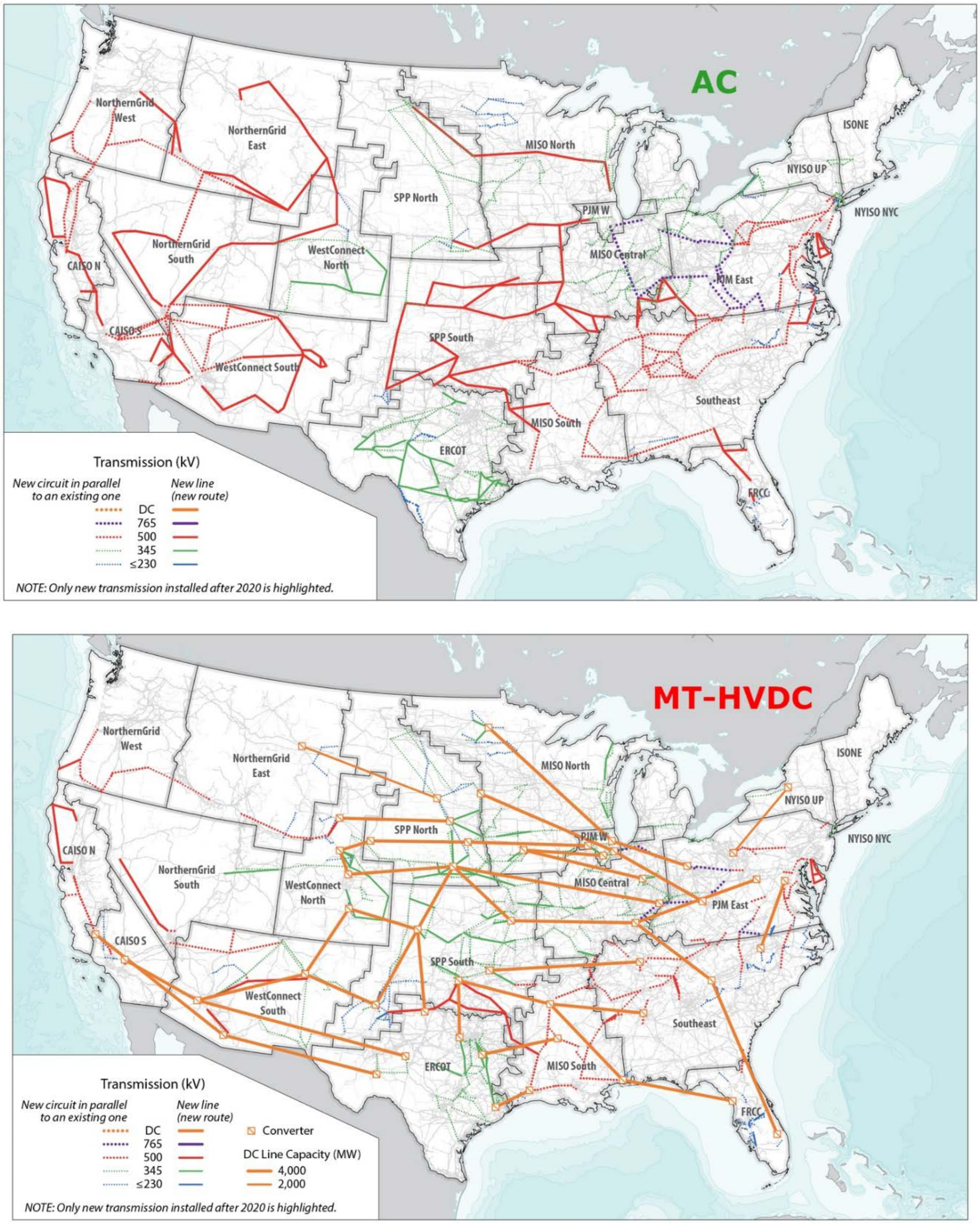

Figure ES-12. Transmission portfolios for the 90% by 2035 Mid-Demand scenario for the AC (top) and MT-HVDC (bottom) transmission frameworks

Only new transmission (developed between 2020 and 2035) is shown with the colored lines on the map. The gray lines in the background represent the existing network.

Regardless of future policy, market, and technology conditions…

Grid planning at the national or multiregional scale requires enhanced institutional coordination, accessible data, and new grid modeling approaches, which have advanced under the NTP Study in partnership with technical and planning experts.

Advancing grid models—merging siloed planning processes, facilitating translations between models, and overcoming computational barriers—is critical to analyzing transmission comprehensively and capturing transmission's multifaceted impacts and potential benefits. In this study, new approaches were developed that can be useful to industry going forward. For example, this study took current industry-grade production cost models and converted them to industry-grade power flow models that were stable enough to use for detailed reliability analysis. The study team used a tool called C-PAGE that is available for industry to convert the production cost modeling results into power flow models for the future model year. An intelligent sampling method was developed for selecting representative hours from a production cost model to use for power flow analysis, recognizing the impacts of significant variations in load, wind, solar, and online generation mixes. The developed tools enable the extraction of power flow cases from production cost model simulations, regardless of generation mix, which can be used for more in-depth reliability studies. The database management system and interactive visualization developed in this study can help planning engineers understand and analyze system behavior for many AC power flow hourly snapshots and contingencies. The study's advanced data analytics can shed light on grid behavior for several AC power flows, providing hourly snapshots and scenarios that the industry may use to examine new transmission investments. The study team also integrated resource adequacy and capacity planning tools to better guide investments to more efficiently address future grid stress conditions. Methods to simulate the impacts of climate change and incorporate them into grid models were also advanced from the study and applied in the analysis. (Chapters 2, 3, 4, 5)

Additional data on potential extreme events, technology advancements, and demand uncertainty will support robust transmission and reliability planning to identify the best expansion opportunities for consumers under changing conditions. Data access enables broader participation and collaboration. The extreme event analysis presented here considered only droughts and heat waves in the western United States. Analyses of different types of extreme events, including cold snaps at locations throughout the United States, will support understanding the full potential resilience benefits of transmission options. More work is needed to properly characterize these events to ensure planning efforts can appropriately identify and size infrastructure, including transmission, to maintain reliability in the face of changing risks. Likewise, other data on technology advancements and demand uncertainly will be equally important. Data availability and access are critical to developing solutions that fit regional and national needs. (Chapters 2, 3, 4, 5)

The identified benefits and expansion opportunities assume coordinated planning and utilization of transmission that goes beyond current practices. Developing guidelines for planners or a framework for coordination between numerous stakeholders could help realize these benefits. Potential benefits of transmission include avoided capital costs, reduced operating costs, increased reliability, and increased resiliency. Many of the scenarios from the NTP Study—particularly the accelerated transmission framework scenarios—assume these benefits could be captured from interregional transmission. But in reality, these benefits may be difficult to fully capture unless action is taken to reduce existing barriers to achieving coordinated planning and utilization of interregional transmission. Of particular importance, as demonstrated from the results of the NTP Study, is increasing opportunities for resource adequacy sharing between regions. A companion report to this study (Simeone and Rose 2024) explores potential solutions to help better integrate resource adequacy sharing into planning time frames. (Chapters 2, 3, 4, 5)

Future Work

The NTP Study addresses a wide range of questions about the role of transmission in the bulk power system in the contiguous United States, along with the reliability and cost benefits that can be gained through accelerated transmission expansion. However, a national-scale, interregional transmission planning effort of this scope is a significant undertaking, and there are several questions that either lie outside the scope of this analysis or require further investigation. GDO intends to continue to lead national-scale grid planning efforts by developing enhanced institutional coordination, accessible data, and new grid modeling approaches in partnership with technical and planning experts. GDO also intends to work with industry to put the findings and tools developed in the NTP Study into action in ongoing planning processes at the state, regional, and interregional levels. Future work could include the following:

- **Transmission siting.** Transmission network data available for the NTP Study are limited in that detailed rights-of-way information and other transmission infrastructure details (age of conductors, tower type, and so on) that could lead to more refined solutions for transmission expansion are not readily available. Additional analysis on the location and routing of transmission—and integration back into planning models—will build confidence in potential transmission solutions. Though not a focus of this study, future in-depth consideration of promising transmission options should include careful consideration of environmental, health, and community impacts and options.
- **Reliability and resilience.** The NTP Study team analyzed several aspects of reliability and resilience, including resource adequacy, contingency analysis, stress analysis, and system flexibility required for reliable operations. These elements of reliability should be further studied—particularly analysis of reactive power coordination, dynamic simulations and frequency response, and voltage ride-through during grid disturbances. In addition, though the NTP Study was able to evaluate discrete extreme weather events for the Western Interconnection, additional events should be studied to understand the role of transmission in

mitigating risks from extreme weather. Future analysis should consider different areas of the country, including across multiple interconnections, and different types of singular and compounded extreme events.

- **Markets and operations.** The NTP Study nodal scenarios envisioned complete coordination between transmission regions in the system's operations. As highlighted by a companion report for the NTP Study, *Barriers and Opportunities To Realize the System Value of Interregional Transmission* (Simeone and Rose 2024), complete coordination is optimistic given the challenges with coordinating the use of existing interregional transmission. These challenges will likely be magnified if the amount of interregional transmission is substantially greater than it is today. Further work should take a closer look at how different levels of market and nonmarket and operational coordination can impact transmission's use and value.
- **Distribution of impacts.** The NTP Study included limited analysis of regional disaggregation of cost savings from accelerated transmission and relative impacts between producers and consumers. The analysis of costs and savings described in this report primarily applies to the contiguous U.S. electricity system as a whole. Additional analysis is needed to assess who would gain the most benefits and who might incur greater costs. Expanding the distributional impacts assessment between the diverse producers and consumers, such as between different socio-economic classes and between generators and transmission, could better inform impacts of transmission expansion to individual households, equity and energy justice issues, and market design and cost recovery to incentive new infrastructure development. Furthermore, expanding the impacts beyond costs and greenhouse gas emissions would provide a more comprehensive evaluation of transmission expansion.
- **Enabling technologies.** The NTP Study considered several transmission technologies and used advanced methods to capture multiple value streams for transmission. However, additional considerations about the best technology to increase capacity between regions, such as reconductoring or the use of grid-enhancing technologies (e.g., dynamic line ratings and power flow control devices), were not studied in detail. Because many transmission additions in the coming decades are likely to include a combination of new transmission and grid-enhancing technologies, better capturing these trade-offs could be an important step in planning studies going forward. In addition, the experience with HVDC technologies in the United States is limited, so opportunities exist to better integrate HVDC technology capabilities into system planning and operations.
- **Grid edge solutions.** The NTP Study did not explore all alternatives to transmission, including distributed resources and nonwires solutions. Energy efficiency, demand response, coordinated electric vehicle charging, virtual power plants, and other demand-side flexibility programs can play important roles in the energy transition. They can reduce the need for transmission and supply-side resources by reducing electricity demand, avoid the need for assets with low utilization, and help support resource adequacy and reliability. However, the scale

of transformation in the NTP Study scenarios—especially the high-demand or decarbonization scenarios—will likely still require large-scale transmission expansion even with the implementation of these nonwires solutions. These solutions may have large impacts on certain regional needs, and further study can improve estimates of these needs.

- **Supply chains.** The NTP Study did not explore the availability of materials and infrastructure to meet the transmission and generation needs in the scenarios. Further study of the supply chains of critical infrastructure is important—particularly HVDC technologies.
- **Policy options and coordination.** The NTP Study included binding state policies in the modeled scenarios and invited TRC Government Subcommittee members and other state policymakers and experts to provide comments on the policy representations and assumptions. Future modeling work should further explore options to achieve emerging federal and state policy goals and targets. Future DOE modeling and analysis activities should include convenings and data to support regional and interregional coordination efforts.

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