National Transmission Planning Study

Chapter 3:

Transmission Portfolios and Operations for 2035 Scenarios

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** 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 (this chapter)** 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

ADS	Anchor Dataset
AC	alternating current
AFUDC	allowance for funds used during construction
ATB	Annual Technology Baseline
EI	Eastern Interconnection
BA	balancing authority
BASN	Basin (WECC Region)
B2B	back-to-back
BESS	battery energy storage systems
BLM	Bureau of Land Management
CAISO	California Independent System Operator
CALN	Northern California (WECC region)
CALS	Southern California (WECC region)
CC	combined cycle
CCS	carbon capture and storage
CEM	Capacity Expansion Model
CEMS	continuous emission monitoring system
CONUS	contiguous United States
DC	direct current
DOE	U.S. Department of Energy
DSW	Desert Southwest (WECC region)
EER	Evolved Energy Research
EI	Eastern Interconnection
EIA	U.S. Energy Information Administration

EIPC	Eastern Interconnection Planning Collaborative
EHV	extra high voltage (>500 kV)
ENTSO-E	European Network of Transmission System Operators for Electricity
EPE	Empresa de Pesquisa Energética
ERAG	Eastern Interconnection Reliability Assessment Group
ERCOT	Electric Reliability Council of Texas
FRCC	Florida Reliability Coordinating Council
GT	gas turbine
GW	gigawatt
HV	high voltage (230 kV ≥ V > 500 kV)
HVAC	high-voltage alternating current
HVDC	high-voltage direct current
IBR	inverter-based resource
ISO	independent system operator
ISONE	Independent System Operator of New England
ITC	investment tax credit
km	kilometer
kV	kilovolt
LCC	line-commutated converter
LCOE	levelized cost of energy
LPF	load participation factor
MISO	Midcontinent Independent System Operator
MMWG	Multiregion Modeling Working Group
MT	multiterminal
MVA	megavolt ampere

MW	megawatt
NARIS	North American Renewable Integration Study
NERC	North American Electric Reliability Corporation
NREL	National Renewable Energy Laboratory
NTP Study	National Transmission Planning Study
NWUS-E	Northwest U.S. West (WECC region)
NWUS-W	Northwest U.S. East (WECC Region)
NYISO	New York Independent System Operator
PCM	production cost model
POI	point of interconnection
PPA	power purchase agreement
PTC	production tax credit
PV	photovoltaic
R&D	research and development
ReEDS	Regional Energy Deployment System (model)
reV	Renewable Energy Potential (model)
ROCK	Rocky Mountain (WECC Region)
ROW	right of way
SERTP	Southeastern Regional Transmission Planning
SPP	Southwest Power Pool
TI	Texas Interconnection
TRC	technical review committee
TWh	terawatt-hour
TW-miles	terawatt-miles
VSC	voltage source converter

VRE	variable renewable energy
WECC	Western Electricity Coordinating Council
WG	Working Group
WI	Western Interconnection
Z2N	zonal-to-nodal

Chapter 3 Overview

The National Transmission Planning Study (NTP Study) evaluates the role and value of transmission for the contiguous United States. The development and verification of transmission portfolios is a critical aspect of the analysis that allows transformative scenarios to be tested against network and operational constraints. This chapter presents the methods for developing the transmission portfolios, the resulting portfolios for the contiguous United States, and alternative portfolios for the Western Interconnection used for focused studies in Chapters 4 and 5 as well as additional insights about how these transmission portfolios are used in hourly operations for a future model year of 2035. The chapter also describes an evaluation of the benefits and costs of transmission for the alternative Western Interconnection portfolios.

The transmission portfolio analysis adopts a subset of future scenarios from the capacity expansion modeling (Regional Energy Deployment System [ReEDS] scenarios; Chapter 2) to translate into nodal production cost and linearized direct current (DC) power flow models. The process for translating from zonal ReEDS scenarios to nodal models required the integration of industry planning power flow cases for each interconnection. The generation and storage capacities from the ReEDS scenarios were strictly adopted. However, given the additional constraints of planning transmission in a detailed network model, the ReEDS transmission capacities and zonal connections were guidelines in the transmission planning stage. The resulting transmission portfolios reflect the general trends from the ReEDS scenarios. In addition, given the broad possibilities of a transmission portfolio for the entire contiguous United States, the focus of the transmission buildout started with interregional needs, followed by other high-voltage intraregional transfers and local needs.

The three ReEDS scenarios adopted for the zonal-to-nodal translation are shown in Table I. These scenarios represent central assumptions from the full set of 96 ReEDS scenarios, representing the Mid-Demand, 90% by 2035 decarbonization, and central technology costs for the three transmission frameworks.

Table I. Summary of Scenarios for Zonal-to-Nodal Translation

Dimension	Limited	AC	MT-HVDC
Transmission framework[1]	AC expansion within transmission planning regions	AC expansion within interconnects	HVDC expansion across interconnects (+AC within transmission planning regions)
Model year		2035	
Annual electricity demand		Mid Demand[1] CONUS: 5620 TWh (916 GW) Western Interconnection: 1097 TWh (186 GW) ERCOT: 509 TWh (93 GW) Eastern Interconnection: 4014 TWh (665 GW)	
CO_2 emissions target		CONUS: 90% reduction by 2035 (relative to 2005)	

[1] See Chapter 2 for further details.

CO_2 = carbon dioxide; AC = alternating current; TWh = terawatt-hour; GW = gigawatt; HVDC = high-voltage direct current

The resulting transmission portfolios developed for the nodal analysis represent one of many possible network expansions that meet the needs of the zonal scenarios. Figures I through III show the three portfolios developed for the contiguous United States. The vast differences between transmission portfolios that all reach a 90% reduction in emissions by 2035 demonstrate that transmission can enable multiple pathways to decarbonization. In addition, all transmission portfolios demonstrate intraregional networks as an important component of expansion and high-voltage networks to collect renewable energy in futures with high amounts of wind and solar.

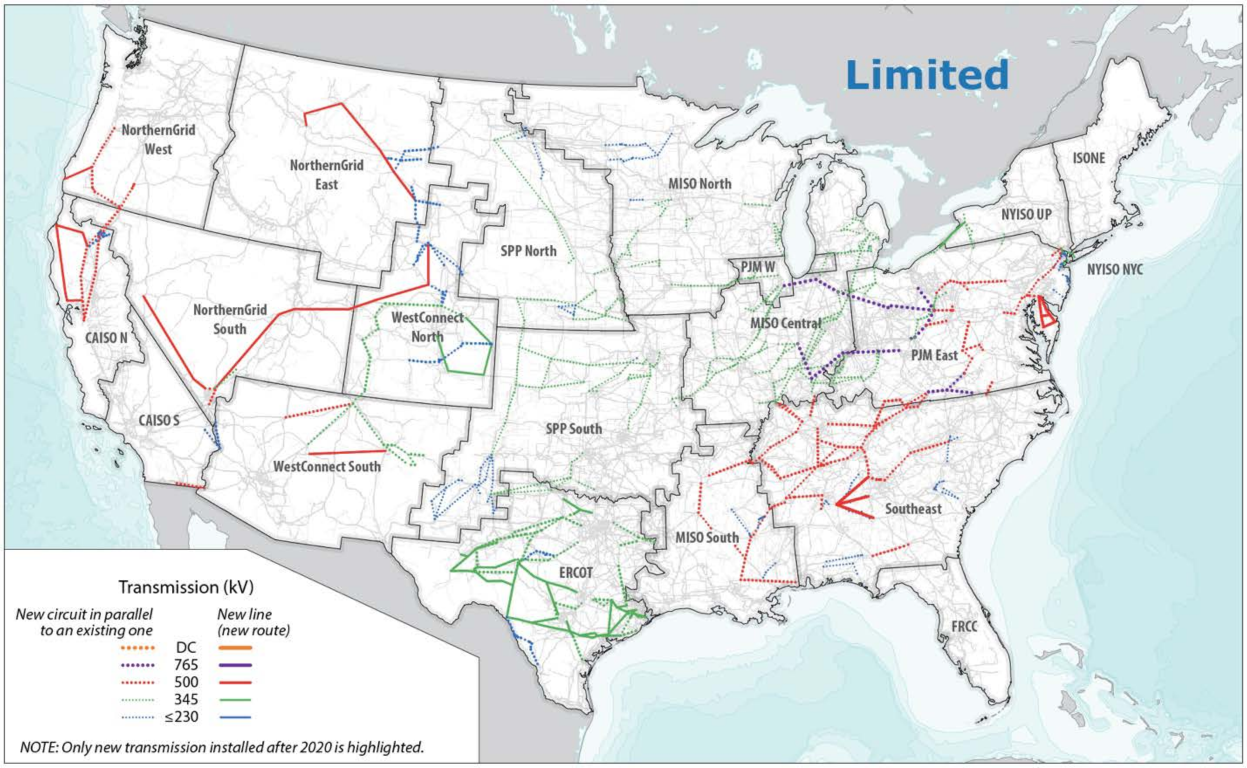

Figure I. Transmission portfolio for the Limited scenario for model year 2035

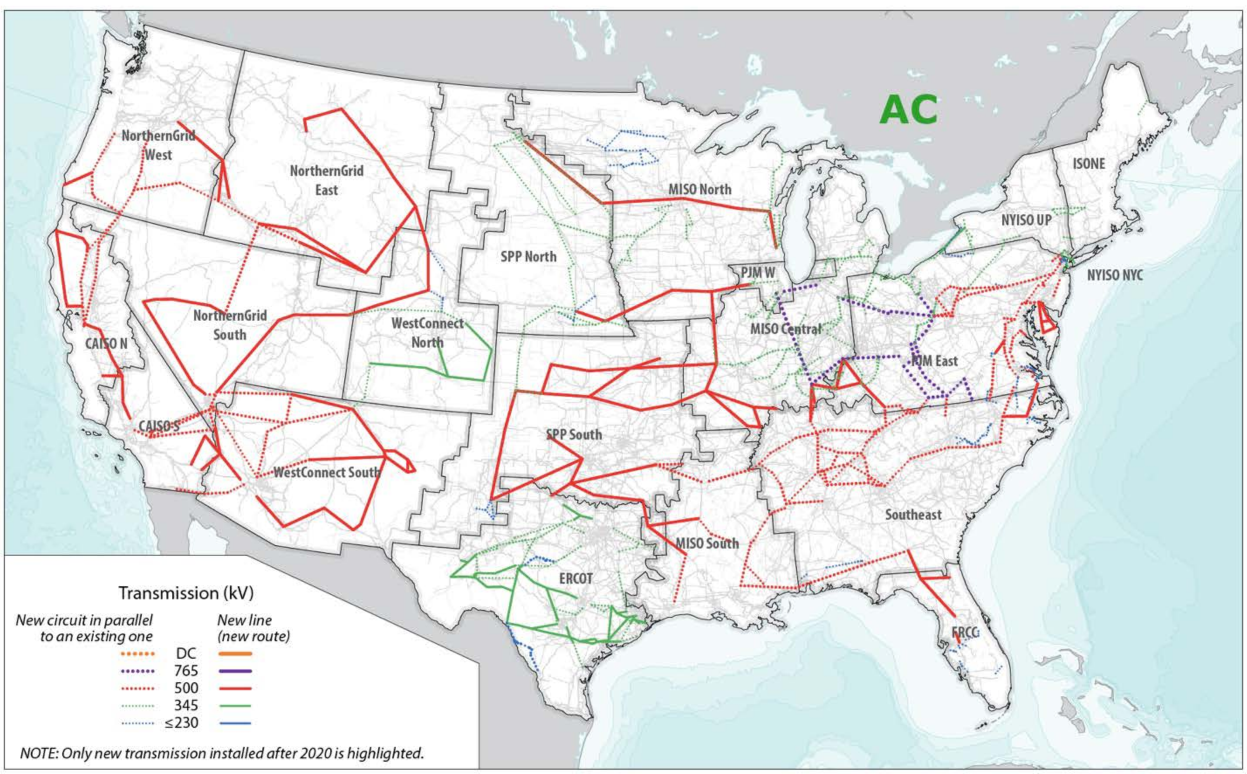

Figure II. Transmission portfolio for the AC scenario for model year 2035

AC = alternating current

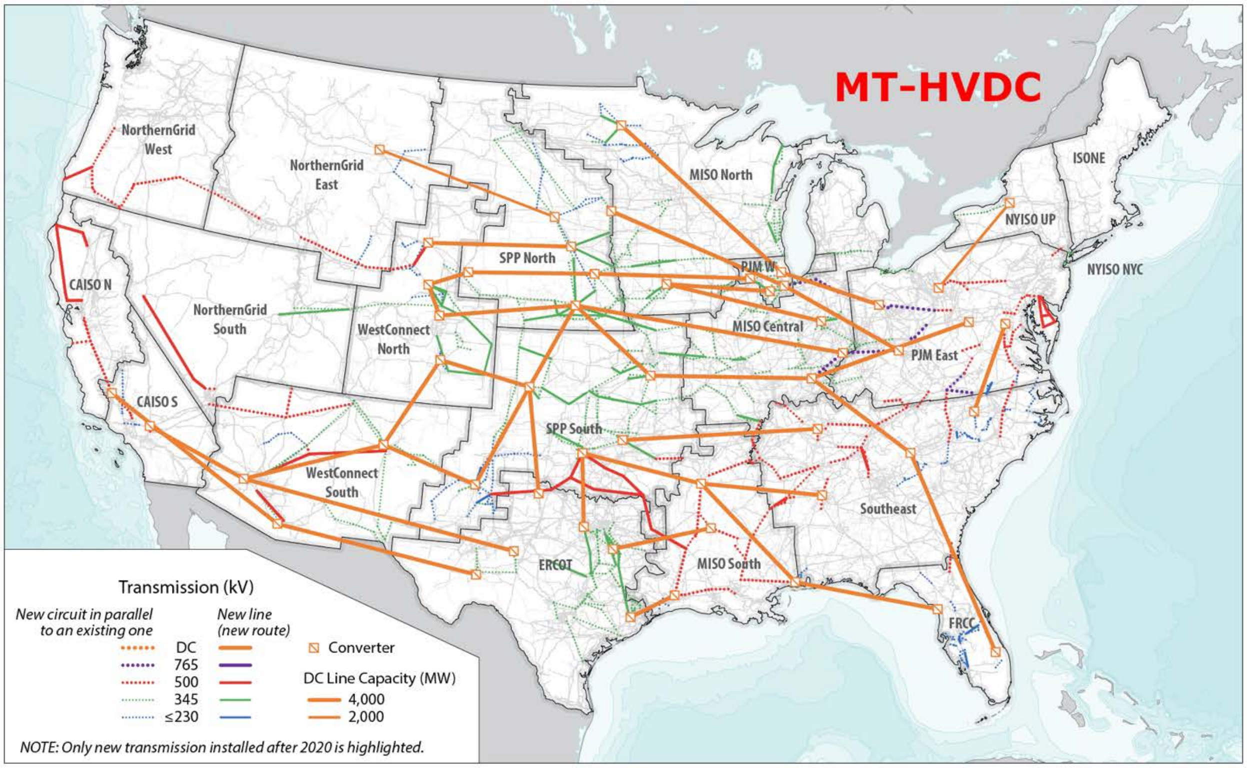

Figure III. Transmission portfolio for the MT-HVDC scenario for the model year 2035

MT = multiterminal; HVDC = high-voltage direct current

The production cost modeling of the scenarios demonstrates the addition of substantial amounts of interregional transmission provides significant opportunities and challenges for grid operators. For example, most regions rely on imports or exports in all three scenarios, but across almost all regions, the alternating current (AC) and multiterminal (MT) high-voltage direct current (HVDC) 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 whereas that number increases to 28% in AC and 30% in the MT-HVDC scenario.

The analysis of the Western Interconnection examines how flows around the West change in response to high levels of renewable energy and transmission. In the AC and MT-HVDC scenarios, there is more variation on the interregional transmission lines, including larger swings diurnally. The patterns of flow are impacted by the generation from solar and the role storage plays in meeting peak demand. On average, the Limited scenario relies on more storage generation during the peak than the AC and MT-HVDC scenarios. In addition, the MT-HVDC scenario also imports across the HVDC lines connecting the Eastern Interconnection to balance the availability of generation in the West, which reduces the need for peaking storage.

The methods developed for the transmission portfolio analysis are novel in that they could be applied on a large geographic scale and include both production cost modeling and rapid DC-power-flow-informed transmission expansions. The incorporation of capacity expansion modeling data was also innovative. This is not the first example of closely linking capacity expansion modeling to production cost and power flow models in industry or the research community. However, several advancements were made to realistically capture the various network points of interconnection for large amounts of wind and solar, build out the local collector networks if necessary, and validate the interregional portfolios that might arise from scenarios that reach 90% reduction in emissions by 2035.

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1 Introduction

The transmission system is a critical part of the electric power system that requires detailed planning to ensure safe and reliable operations of the grid. A cornerstone of power system planning for decades is nodal modeling and analysis. Nodal power system models consist of the specific components of the system, such as generators, loads, and transmission lines in mathematical representations to use for analysis and simulation. To adequately evaluate the role and value of transmission for the contiguous United States (CONUS), the National Transmission Planning Study (NTP Study) uses nodal models for various analyses regarding power system planning and reliability. The use of the nodal models in the NTP Study is part of a broader framework that applies multiple models and integrates aspects of reliability and economics to evaluate how transmission can help meet the needs of future systems. This chapter details the methods for compiling detailed nodal models of the contiguous U.S. power system and using this dataset to build transmission portfolios for the future as well as the operational insights from production cost modeling of future U.S. grids.

Modeling the entire contiguous U.S. electricity system at a nodal level serves two primary objectives: 1) it verifies the feasibility of future power systems that can meet the physical constraints that dictate operations and 2) it provides insights on grid balancing that match the temporal and spatial granularity with which grid operators view the system. Table 1 further defines several subobjectives of nodal modeling. To achieve these objectives, the study team combined industry planning models with several scenarios adopted from zonal modeling of the CONUS using the Regional Energy Deployment System (ReEDS) model, detailed in Chapter 2.[2] These future scenarios are translated into nodal models by combining existing network details with plans for generation, storage, and transmission. The result of this "zonal-to-nodal" (Z2N) translation is a detailed nodal model of a future electric power system of the United States. This resulting nodal model includes unit-level generation and node-to-node transmission components, among many other details of the physical assets on the grid.

In the process of creating nodal models of the future, transmission portfolios are developed that meet the needs of the power system and the intent of the scenario. The development and verification of the transmission portfolios is a critical aspect of the analysis that allows transformative scenarios to be tested against network and operational constraints. The nodal models, inclusive of transmission portfolios, produced with this exercise are used across multiple modeling efforts of the NTP Study, some of which are detailed in Chapters 4 and 5 of this report.

Section 2 of this chapter presents the methods of the Z2N translation and the process to plan the transmission portfolios. Section 3 presents the resulting transmission portfolios of the contiguous United States for three scenarios for the model year 2035 and hourly

[2] The ReEDS model contains 134 zones comprising the contiguous U.S. electricity system. ReEDS finds the least-cost mix of generation, storage, and transmission to balance load and supply given various technical, policy, and cost constraints for a set of years into the future. Chapter 2 details the long-term planning scenarios developed with ReEDS, which is focused on the years out to 2050.

operational insights. Section 4 presents analysis of the Western Interconnection of the United States, including alternative transmission portfolios and operations, for a similar set of scenarios in addition to an economic comparison of the investment and operations of the scenarios from this section. Conclusions and potential future work are discussed in Section 5.

Table 1. Objectives of Nodal Modeling for the NTP Study

Verify the feasibility of future scenarios by incorporating constraints that match physical realities of operating power systems
- The physical network model captures power flow distributions and loading patterns across network elements (individual transmission lines and transformers). - Physical infrastructure limits are captured (individual equipment ratings). - Generators have distinct points of interconnection (POIs) and therefore drive related transmission network upgrades. - The constraining of transmission flows aims to represent physical transmission margins that emulate actual operations. - Enable more seamless data flow and obtain information to feed forward and feed back to other modeling domains.
Gain grid-balancing insights based on detailed spatial and temporal modeling
- Establish whether the system can balance load and generation at an hourly temporal resolution considering both intraregional and interregional transmission network constraints. - Identify which resources are serving load during stressful periods and the role played by the transmission network to enable this. - Analyze the use of expanded interregional transmission and how this impacts system operations. - Analyze potential intraregional network constraints and the resulting need for upgrades and/or new investments. - Test the latent and potentially increased need for flexibility in parts of CONUS-wide models (including the role of transmission in providing flexibility). - Assess the operation of energy storage to support load and generation balancing, including the trade-offs with transmission network constraints. - Understand how much and where variable renewable energy (VRE) curtailment is happening.

2 Methodology

The following sections outline the methodology and workflows for the Z2N translation and the additional analysis that is performed with the nodal models. This is illustrated as a conceptual outline in Figure 1. The zonal input is a ReEDS scenario, which has 134 zones across the CONUS model.[3] The final nodal-level result is 1) a model year 2035 transmission portfolio that delivers broad-scale benefits and adheres to network constraints and 2) a production cost model that can be used to understand the operations at hourly resolution over a year (8,760 hours). Building the transmission portfolios and the nodal production cost model involves two primary steps:

1. **Disaggregation:** The assets that ReEDS builds (generation and storage) are disaggregated spatially across the United States within the zones and using other underlying information on asset location,[4] and assets are assigned points of interconnection (POIs) that already exist on the network.

2. **Transmission expansion planning:** New transmission is built within the nodal network models to connect the generation and storage assets, and additional transmission is built to connect regions and zones. The transmission for connecting regions and zones uses ReEDS results as an indication of need, but the exact transmission capacities from ReEDS are only guides and not prescriptive.

This transmission planning phase uses a combination of automated methods and an interactive transmission expansion planning approach to make decisions about discrete transmission expansions. The resulting transmission portfolios and production cost results are presented in this chapter and are used in Chapters 4 and 5 of this report for subsequent analysis. The following section describes the Z2N translation process.

[3] See Chapter 2 for more details on ReEDS and the zonal results.
[4] Wind and solar are built within the ReEDS scenarios based on supply curves with discrete 11.5-km x 11.5-km grid cells (for both wind and solar) across the United States. Therefore, these assets are at a finer resolution than the 134 zones and are interconnected spatially in the network models according to those grid points. See Chapter 2 for a more detailed explanation of ReEDS outputs.

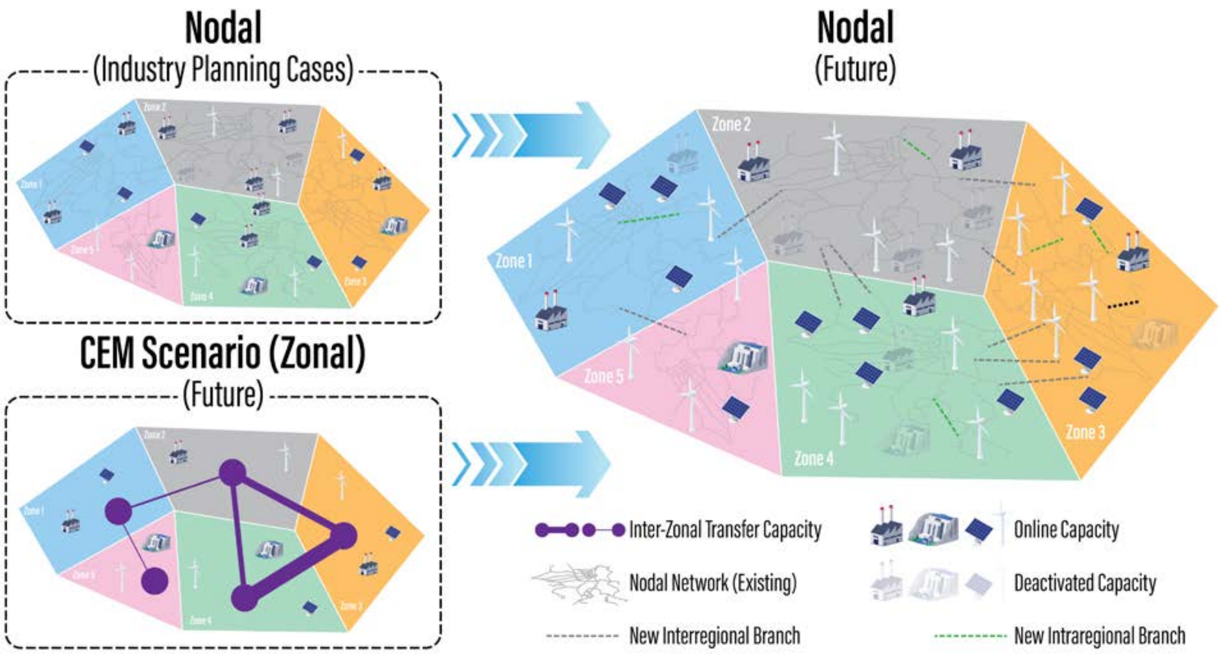


Figure 1. Conceptual outline of zonal-to-nodal translation

CEM = Capacity Expansion Model

A note on using multiple software tools and workflows

Several of the results in this chapter originate from the earlier ReEDS scenarios, which represent a version that was completed midway through the NTP Study. These results are presented in Section 4. One of the primary purposes for using these interim results is the downstream models, especially the alternating current (AC) power flow models, can be very challenging and time-consuming to build and using the earlier scenario results allowed for a full run-through of the multimodel linkages—capacity expansion, production cost, and AC power flow—to be completed within the timeline of the study. There are slight differences between earlier and final scenarios (the scenarios analyzed in Chapter 2 are “final”), but both have the same general trends with respect to generation and transmission capacity buildout to the model year for this chapter: 2035. More details on the advancements made between earlier scenarios and final ReEDS scenarios are summarized in Chapter 1, Appendix A of this report.

The industry planning cases that are a starting point for the nodal analysis are the same between earlier and final scenarios. In building the future year nodal database, which requires the disaggregation and transmission planning steps outlined next, the same general principles for the Z2N process are used. However, though comparisons across modeling software of the same type (i.e., production cost) are not done in this chapter or anywhere else in the study,[1] there are still lessons from analyzing each set of scenarios that can strengthen the lessons from the study, which is the reason for including two sections of results. In addition, there is value to industry in having multiple production cost databases and transmission portfolios available as an outcome of the NTP Study, of which these will both be made available to industry and others where possible. Table 2 gives a summary of how earlier and final scenarios are used in this and other chapters.

Table 2. Different Use Cases for the Two Iterations of Scenarios Presented in This Chapter

Iteration of Zonal ReEDS Scenarios	Section for This Chapter	Geographical Coverage Represented in the Models	Other Chapters That Directly Use These Capacity Expansion Iterations
Earlier	Section 4	WI[1]	Chapter 4; Chapter 5
Final	Section 3	CONUS	Chapter 2

WI = Western Interconnection; EI = Eastern Interconnection; CONUS = Contiguous United States

2.1 Zonal-to-Nodal Translation

The Z2N translation is focused on transmission expansions and production cost modeling. The Z2N translation is a common process in industry, where resource plans are often developed at a zonal scale, but those plans eventually must be mapped to a nodal network model for a detailed transmission planning exercise.[5] There are many challenges to this process because zonal models, where policies or other techno-economic realities can be represented in detail, do not have the level of detailed network and physics-based constraints that exist in nodal models.

For the NTP Study, the challenges in this process are magnified because 1) the nodal datasets for the CONUS model(s) are very large, 2) the change with respect to the initial grid configuration is substantial, and 3) there is significant diversity in resources and network configurations across the United States, so strategies for the Z2N translation must be flexible.

The compiling and building of the nodal models follow a few basic principles:

- **Reproducibility between scenarios:** There are many potential methods to undertake the Z2N translation, as indicated by the multiple methods explained later in this chapter. However, the methods are reproducible across scenarios. Therefore, any comparisons of results in this chapter are across scenarios developed using the same methods.
- **Representing industry practice:** Z2N should build from industry best data and best practices. This starts with using industry planning models and learning from industry practices in their latest planning studies and in consultation with technical review committee (TRC) members. Section 2.1.1 details the starting datasets.
- **Using capacity expansion findings as a guideline:** Although generation capacity, storage, and demand are directly translated from the scenario-specific ReEDS outcomes, the prescribed interregional transfer capacities are used as a guideline for transmission expansion needs when building the nodal models.

An overview of the primary steps that form the entire Z2N translation is illustrated in Figure 2, starting with the results from ReEDS (1); moving into the disaggregation of zonally specified generation capacity, storage capacity, and demand into nodes (2); followed by a set of transmission expansion steps (3). The underlying nodal datasets that support this approach are further described in the next section.

[5] For example, California Public Utilities Commission. 2022. “Methodology for Resource-to-Busbar Mapping & Assumptions for The Annual TPP.” https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integratedresource-plan-and-long-term-procurement-plan-irp-ltpp/2022-irp-cycle-events-and-materials/2023-2024- tpp-portfolios-and-modeling-assumptions/mapping_methodology_v10_05_23_ruling.pdf

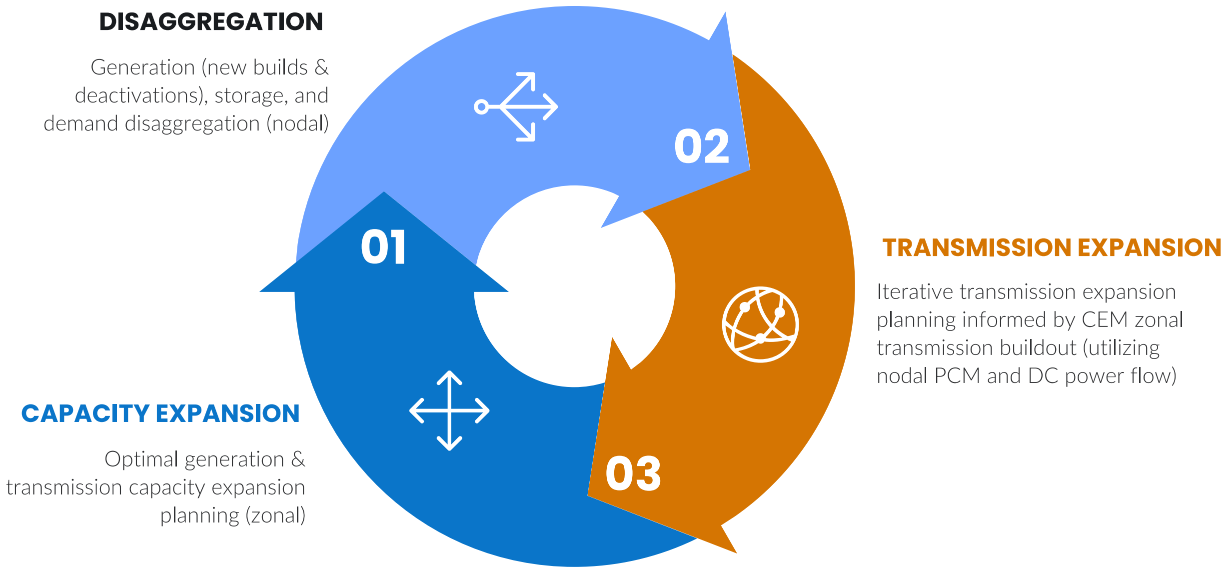


Figure 2. Overview of zonal-to-nodal translation approach

Note: Figure incorporates iteration back to capacity expansion (ReEDS).
CEM = Capacity Expansion Model (ReEDS); PCM = Production Cost Model

2.1.1 Geographic extent and nodal datasets

The CONUS bulk power system model used for the NTP Study comprises three regions—the Eastern Interconnection, Western Interconnection, and the Electric Reliability Council of Texas (ERCOT), shown in Figure 3. These interconnections are asynchronously interconnected through several relatively small back-to-back (B2B) HVDC converters.[6] The geospatial scope of the NTP Study is the contiguous United States. However, portions of Canada and Mexico are modeled but remain unchanged with respect to resources and transmission infrastructure in the study.[7]

[6] There are seven B2Bs between the contiguous U.S. portions of the Eastern and Western Interconnection (each ranging from 110 to 200 megawatts [MW]) and two between the Eastern Interconnection and ERCOT (200 MW and 600 MW). Not shown in Figure 3 are two B2B converters between Texas and Mexico (100 MW and 300 MW) as well as one between Alberta and Saskatchewan in Canada (150 MW).
[7] Industry planning models that are used for this study (see Table 3) include portions of Canada and Mexico. The regions are still part of the production cost and power flow models used in this chapter, but regions outside of the United States were not modified from the industry planning cases (i.e., load, generation, or transmission was not added).

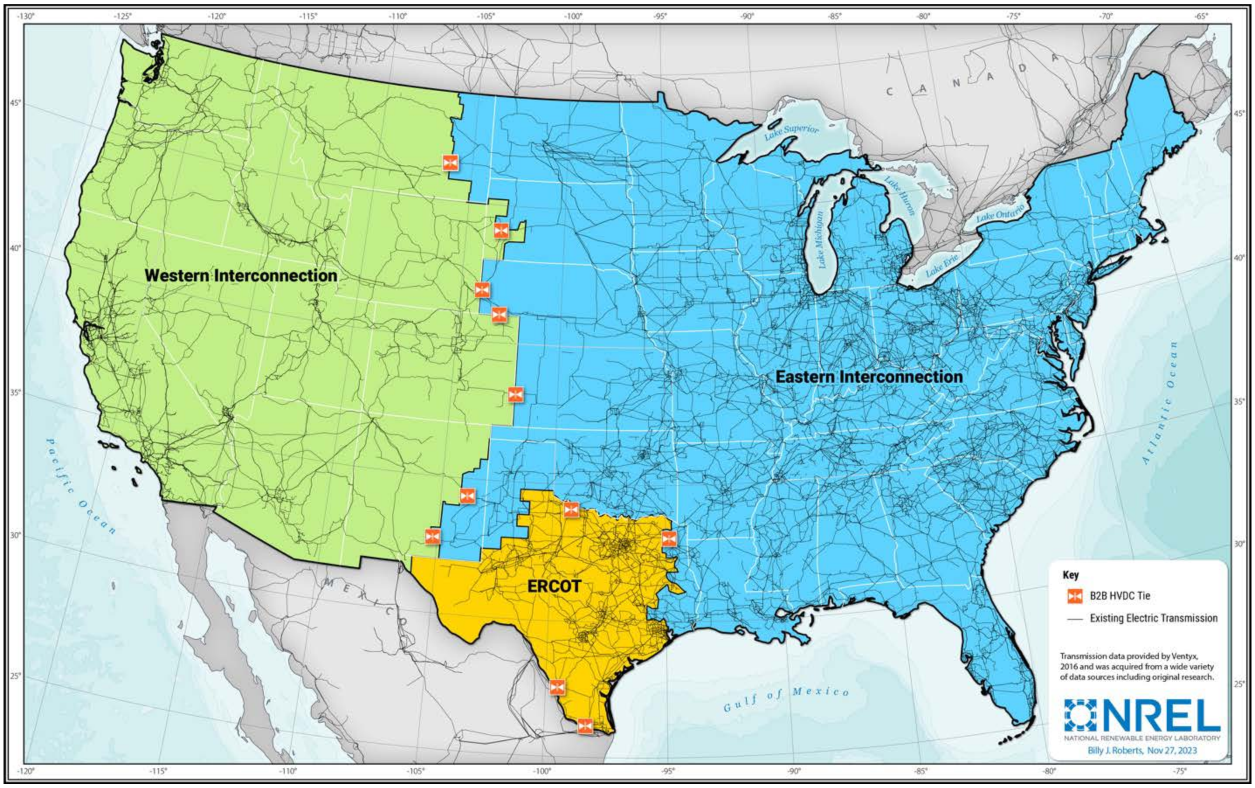


Figure 3. Map of the three interconnections of the bulk U.S. power system

Note: Map highlights the interconnectivity between interconnections via existing B2B HVDC interties.

The nodal datasets used for the NTP Study are compiled from the industry planning cases from the Western Electricity Reliability Council (WECC),[8] Eastern Interconnection Reliability Assessment Group (ERAG),[9] and to some extent ERCOT[10]—the details of which are summarized in Table 3. These datasets typically do not have all relevant details to inform a Z2N translation, i.e., geographical coordinates required to map zonal capacity expansion results to individual nodes or run future scenarios beyond the planning case timeline. Though WECC publishes a fully functional production cost model as part of its Anchor Dataset (ADS), the ERAG and ERCOT available data lack component information to build and run production cost models, such as generator unit constraints (ramp rates, minimum stable levels, and minimum uptime and downtime, among others), detailed hydro availability, or hourly wind and solar profiles. A task within the NTP Study was designed to fortify the industry planning cases for the Eastern Interconnection and ERCOT to be suitable for this study. The WECC ADS model details were used directly for the CONUS scenarios. For the Western Interconnection analysis

[8] Through the well-known WECC Anchor Dataset (ADS) (Western Electricity Coordinating Council 2022).

[9] The Eastern Interconnection Reliability Assessment Group (ERAG) oversees the Multiregional Modeling Working Group (MMWG), which is responsible for assembling nodal network models for the Eastern Interconnection (among other responsibilities).

[10] WECC is the regional entity responsible for reliability planning and assessments for the Western Interconnection and has nodal models of the Western Interconnection available for members. EIPC is a coalition of regional planning authorities in the Eastern Interconnection that compiles a power flow model of the Eastern Interconnection based on regional plans. ERCOT did not provide an updated power flow model from this study; therefore, data were compiled from publicly available sources and purchased data.

of the earlier scenarios, an augmented model was developed to include five future transmission projects. For details on the development of the Western Interconnection database, see Konstantinos Oikonomou et al. (2024).

The nodal datasets of the Eastern Interconnection, Western Interconnection, and ERCOT are each developed independently and then combined to form the CONUS nodal dataset. A summary of sources for the data in the nodal models is presented in Table 3, with a more comprehensive table in Appendix A.1. Some of the benefits realized and challenges faced in compiling a CONUS-scale dataset are summarized in Appendix A.2.

Table 3. Overview of Data Sources Used for Building CONUS Datasets

Description	Eastern Interconnection	Western Interconnection	ERCOT
Network topology (node/branch connectivity)[1]	ERAG MMWG 2031[2]	WECC ADS 2030 v1.5	EnergyVisuals[5]
Node mapping (spatial)	NARIS, MapSearch, EnergyVisuals, EIA 860	NARIS MapSearch, EnergyVisuals, EIA 860	NARIS, MapSearch, EnergyVisuals
Generation capacity (technology)	NARIS, EIA 860, EIPC	WECC ADS 2030 v1.5, EIA 860	NARIS
Generation techno-economic characteristics[3]	NARIS, EIA CEMS	WECC ADS 2030	NARIS

[1] Augmented through stakeholder feedback to include the most recent available data on network updates/additions.

[2] Eastern Interconnection Reliability Assessment Group (ERAG) Multiregional Modeling Working Group (MMWG) 2021 series (2031 summer case).

[3] Includes heat rates, minimum up-/downtimes, ramp rates, and minimum stable operating levels.

[4] Hourly/daily/monthly energy budgets (as appropriate).

[5] Power flow case files (2021 planning cases).

ADS = Anchor dataset (Western Electricity Coordinating Council 2022); CEMS = continuous emission monitoring system; EER = Evolved Energy Research, MMWG = Multiregional Modeling Working Group; NARIS = North American Renewable Integration Study (National Renewable Energy Laboratory [NREL] 2021a); WECC = Western Electricity Coordinating Council

2.1.2 Modeling domains and tools

Several modeling domains are applied as part of the iterative Z2N translation process. For disaggregation, many custom tools were built to map zonal resources and network assets. A summary of the primary modeling tools for the transmission expansion phase is shown in Table 4.

Table 4. Primary Models Used in the Transmission Expansion Phase of the Z2N Translation

Step in Transmission Planning Phase of Translation	Primary Modeling Tools
1. Production cost	Sienna,[11] GridView[12]
2. Power flow and contingency	PSS/E,[13] PowerWorld Simulator[14]
3. Visualization	QGIS,[15] Grid Analysis and Visualization Interface[16]

The outputs of the ReEDS scenarios are used as inputs into the disaggregation step. The objective of disaggregation is to translate new electricity demand, generation, and storage that is built in the scenario from ReEDS to augment an established industry planning case to build scenario-specific nodal production cost models. Section 2.2 details this process.

However, not all resources are easily placed on the network with automated processes, and additional expertise is needed to make decisions about resource allocation to nodes. Interventions are needed for some specific instances, where the resource—for example, wind—might be in such high quantities that a substation or entire high-voltage/extra high-voltage (HV/EHV) collector network[17] might need to be considered. These interventions are where the transmission expansion planning phase begins. The software and tools in Table 4 are used to both ensure generation and storage have sufficient transmission to interconnect to the network and transmission portfolios are designed to meet the needs of the system and reflect the intention of the ReEDS scenario. Several times throughout the design of the transmission portfolios, production cost models and DC power flow models are run and analyzed to assess how the system operates—that is, energy adequacy, hourly balancing of supply and demand, variable renewable energy (VRE) curtailment, individual branch loading, and interface flows. Section 2.3 details this phase of the Z2N process.

The nodal production cost models are the core analytical tools used in the Z2N process—employed extensively in the transmission expansion planning phase and producing the operational results analyzed for Sections 3 and 4. They also seed the operating points for the more detailed reliability analysis described in Chapter 4 and Chapter 5. The open-source modeling framework, Sienna/Ops, is used as the

[11] Sienna: https://www.nrel.gov/analysis/sienna.html, last accessed: February 2024.
[12] GridView: https://www.hitachienergy.com/products-and-solutions/energy-portfolio-management/enterprise/gridview, last accessed: May 2024.
[13] Siemens PSS/E, https://www.siemens.com/global/en/products/energy/grid-software/planning/pss-software/pss-e.html, last accessed: February 2024.
[14] PowerWorld Simulator, https://www.powerworld.com/, last accessed: March 2024.
[15] QGIS, https://www.qgis.org/en/site, last accessed: May 2024.
[16] For the final scenarios, the study authors developed the Grid Analysis and Visualization Interface to help visualize the system operations and support transmission planning. Details are presented in Appendix C.2.
[17] As defined in ANSI C84.1-2020 where HV = 115–230 kilovolts (kV) and EHV = 345–765 kV.

production cost model for transmission planning and operational analysis for final scenarios (Section 3 of this chapter) whereas GridView[18] is used for earlier scenarios (Section 4 of this chapter).

2.2 Disaggregation

The Z2N disaggregation relies on two principles about how to convert ReEDS results to nodal models: 1) generation and storage planned in ReEDS must align with the nodal model very closely (i.e., prescriptive) and 2) transmission results from ReEDS are indicative of the needed transmission capacity to move energy between regions. Demand is also prescriptive because it is an input to the zonal model. The distinction between the prescriptive and indicative use of zonal results is summarized in Figure 4.

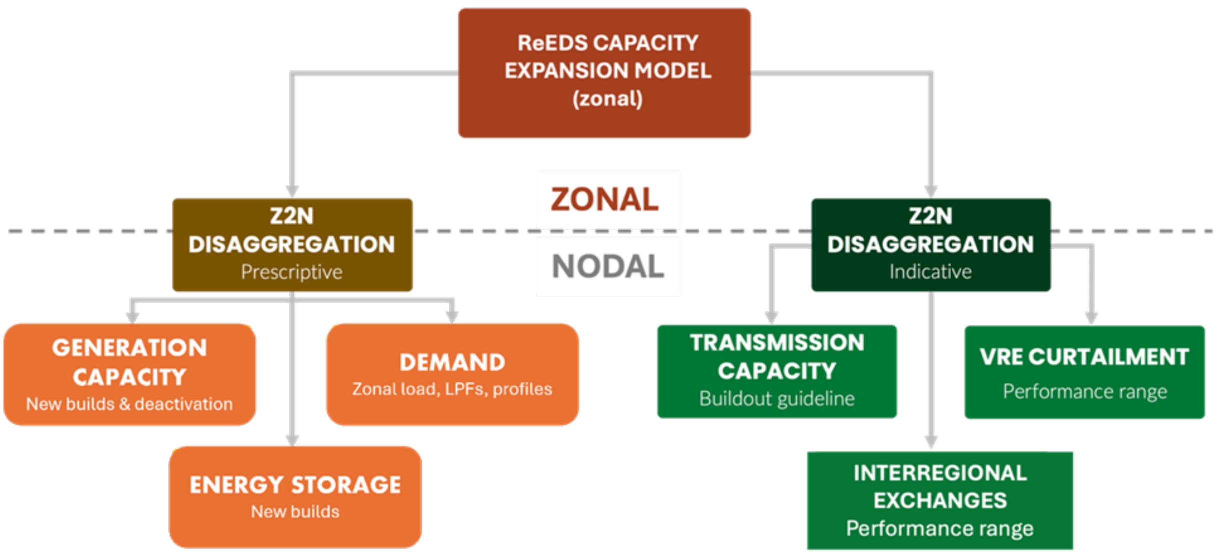


Figure 4. Overview of the zonal results flowing into the nodal model

LPF = load participation factor

The prescriptive component of the Z2N process comprises four primary steps:

1. **Demand disaggregation:** Demand disaggregation is needed to represent load profile time series in nodal production cost models because only zonal demand is provided by ReEDS outcomes. ReEDS zonal demand is disaggregated into nodes for each ReEDS region based on load participation factors (LPFs)[19] derived from the industry planning power flow models. This process is depicted geospatially in in Figure A-38 in Appendix A.3, demonstrating how a single zonal

[18] GridView: https://www.hitachienergy.com/products-and-solutions/energy-portfolio-management/enterprise/gridview, last accessed: May 2024.

[19] Load participation factors (LPFs) are a measure to assess the contribution of an individual load to overall load in a region. In the context of the NTP Study, LPFs are derived from absolute nodal loads in the nodal datasets to generate load profiles from ReEDS zonal loads for nodal production cost model analysis.

demand profile from a ReEDS zone is disaggregated into the many nodes based on the relative size of each load (their LPFs).

2. **Establish the generation and storage capacity needs for each zone in the nodal model year:** To establish the amount of generation and storage to add to the system, the study team compared industry planning cases with the ReEDS scenario. Generation and storage capacity is added or subtracted (i.e., deactivated) to the nodal models to reach prescribed capacities defined by ReEDS.[20]

3. **Ranking of nodes—POIs:** To assign zonal capacities to nodal models, the study team ranked nodes by generation and storage capacity POI favorability. Viable nodes[21] are ranked by build favorability. Higher build favorability considers the following (in descending order): 1) nodes with more deactivated/retired capacity, 2) nodes at higher voltage levels, 3) nodes or surrounding nodes with large loads attached.[22]

4. **Adding generation and storage capacity:** The final step in the disaggregation is to link new generation and storage capacity defined in ReEDS to actual nodes, or POIs. Figure 5 illustrates the spatial clustering of solar photovoltaics (PV) and land-based wind to POIs. After initial clustering to POIs, further refinement may be required to ensure node capacities are reasonable given network constraints. Appendix A.3 contains further details on this step.

[20] ReEDS compiles any known generator retirements from EIA or other sources and exogenously enforces them. In addition, ReEDS can retire generation economically. See Chapter 2 for more details.
[21] Nonviable nodes may be terminals of series capacitors, tap-points, fictitious nodes to indicate conductor changes (or three-winding transformer equivalents) and disconnected/isolated busses.
[22] For allocating distributed energy resources (distributed solar PV), which is consistent across all NTP scenarios (sensitivities on types of distributed energy resources, quantity or distribution of distributed energy resources is out scope for the NTP Study).

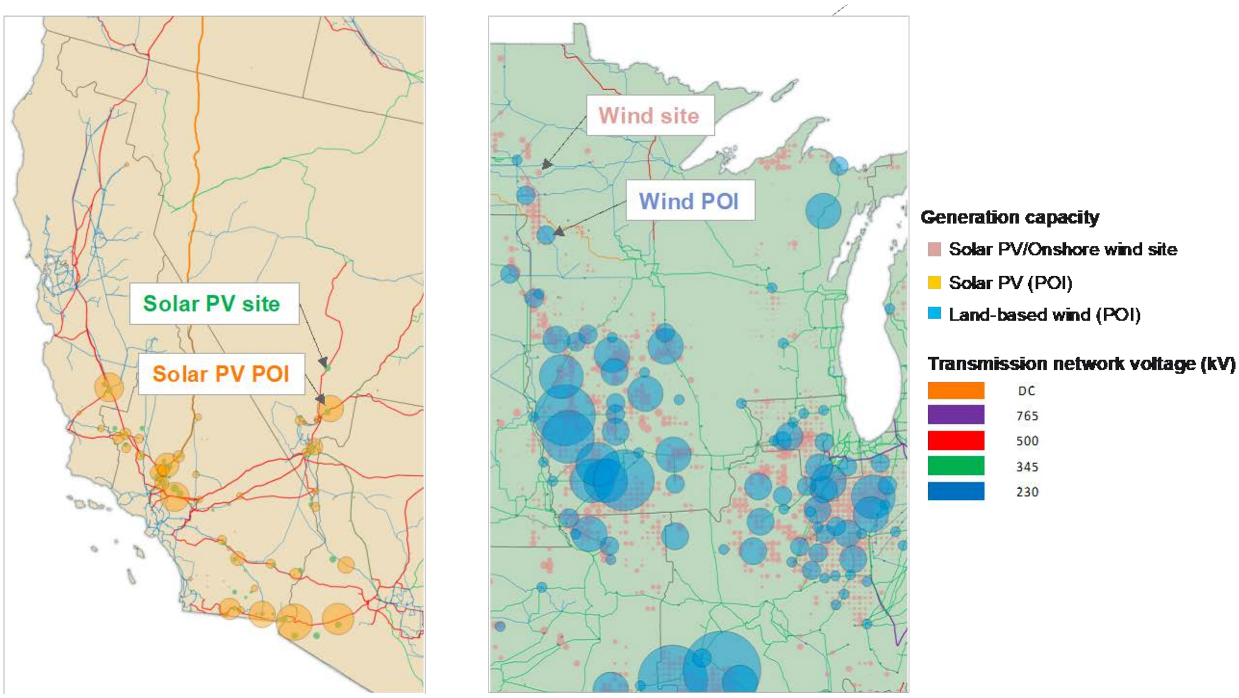


Figure 5. Illustration of VRE disaggregation process as part of Z2N translation

Note: The VRE disaggregation is demonstrated for solar PV (left) and land-based wind (right) where individual solar PV and wind sites are assigned to POIs (nodes).

2.3 Transmission Expansion

Nodal transmission expansion comprises a key part of the overall Z2N translation workflow. The scenarios for the NTP Study are transformational, in part because of the decarbonization targets enforced in several of them and the scale of transmission allowed. Therefore, the study team developed a transmission expansion process that could meet the demands of potentially large buildouts in interregional and regional networks. In addition, this process needed to be manageable at an entire interconnection and contiguous U.S. scale. This manageability is achieved through stages of increasing complexity to maintain tractability as the transmission portfolios are built out in the nodal production cost model. This staged process is summarized in Figure 6. Each stage becomes progressively more constrained and can have several internal iterations per stage.

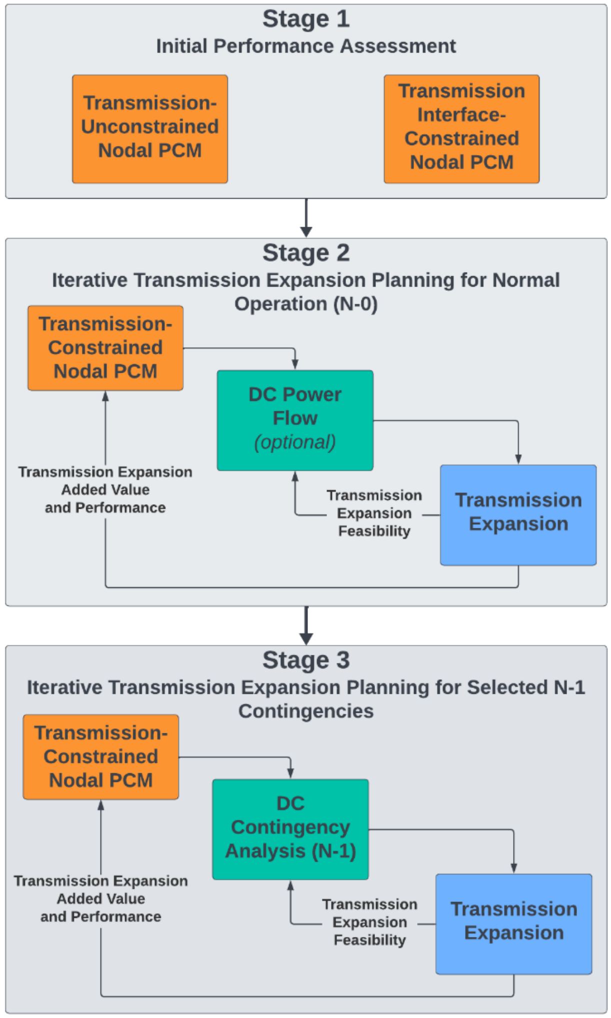


Figure 6. Stages of transmission expansion planning

Orange boxes indicate a nodal production cost model, teal boxes indicate DC power flow, and blue boxes indicate transmission expansion decisions by a transmission planner.

The transmission expansion planning process applies the staged principles to remain consistent across CONUS and is not intended to exactly replicate transmission planning processes or adopt regionally specific technical transmission guidelines/standards as applied by regional transmission planners, owners/developers, or utilities. In addition, to help visualize the large changes and impacts to the Z2N scenarios, the Grid Analysis and Visualization Interface tool was created to visualize hourly production cost model results (see Appendix C.1 for an overview of this tool).

The sections that follow provide further details of the staged transmission expansion process depicted in Figure 6.

Stage 1: Initial network performance assessment

Stage 1 is a performance assessment intended to provide an initial analysis of system operations and transmission network use before transmission expansion is undertaken.

The initial disaggregation of resources has already been implemented when this first stage of transmission expansion planning is reached (see Section 2.2). Therefore, the Stage 1 nodal production cost model runs contain all the generation and storage resources built in the ReEDS scenario.

Stage 1 is implemented by a nodal PCM with two core transmission network formulations:[23]

- **Transmission unconstrained:** No transmission interface or branch bounds are applied (analogous to a "copper sheet" formulation but with network impedances represented to establish appropriate flow patterns)
- **Transmission interface constrained:** Only transmission interface limits are enforced (individual tie-line branch limits are unconstrained).[24]

The unconstrained nodal production cost model establishes where power would want to flow without any network constraints and hence establishes an idealized nodal realization without network bounds. The semibounded interface-constrained nodal production cost model establishes an indicator for interregional and enabling intraregional transmission network needs by allowing individual branch overloading but ensuring interregional tie-line flows remain within the limits established from the ReEDS transfer capacities (aggregated to transmission planning regions).[25]

At this stage, the following system performance indicators are assessed (for both transmission-unconstrained and transmission interface-constrained formulations):

- Interregional power flow patterns across sets of transmission interfaces (tie-lines)
- Individual tie-line power flow patterns and loading profiles
- Individual HV and EHV transmission line loading profiles
- Regional wind and solar PV curtailment levels
- Operations of dispatchable resources.

After establishing general flow patterns within and between regions in Stage 1, the study team proceeded with Stage 2.

[23] Further details on transmission formulations are provided in Appendix A.4.
[24] Transmission interfaces are defined as the sum power flows across each individual tie-line part of the given interface.
[25] Using constrained and unconstrained production cost models as a way to gather information about the system potential is typical in industry planning, for example, in Midcontinent Independent System Operator (MISO) (Dale Osborn 2016).

Stage 2: Iterative transmission expansion planning for normal operations (system intact)

Stage 2 expands the HV and EHV transmission networks for normal operating conditions (system intact). To plan the transmission expansion, an iterative approach is deployed, which includes the following steps:

1. **Performance assessment:** From a set of nodal production cost model results (Stage 1 transmission interface-constrained or a Stage 2 iteration), assess network use metrics such as interface flow duration curves, loading duration curves of individual tie-lines, individual HV and EHV transmission line loading profiles, VRE curtailment, dispatch of resources (generation, storage), and unserved energy.
2. **Transmission expansion planning:** Based on the interface flow patterns, iteratively propose and test nodal transmission expansion options to increase transmission capacities while managing HV and EHV network overloads. The quick assessment of the feasibility of the proposed transmission expansion options can be obtained by employing DC power flow[26] simulations as an intermediate step prior to running a new nodal production cost model simulation including the additional transmission network elements.
3. **Nodal production cost model:** Once a substantial set of new transmission expansions meets performance metrics in the DC power flow simulations, the nodal production cost model is adapted with the new transmission and run with an increasing set of network constraints.

In each iteration of the Stage 2 transmission expansion process described previously, different transmission expansion priorities are addressed. Figure 7 shows the priority order followed for the definition of the network expansion options defined in Stage 2.

Once the Stage 2 transmission expansion planning process is complete, the system operation performance is assessed using a constrained nodal production cost model formulation incorporating all the proposed transmission expansion portfolios. Given good performance in the nodal production cost model, this establishes the starting point for Stage 3. Criteria considered in evaluating production cost model performance are unserved energy, new transmission utilization, and VRE curtailment.

[26] DC power flow simulations are performed over a subset of the 8,760 operating conditions from the nodal production cost model results. These representative operating conditions are called “snapshots.” The selection of these snapshots is made to capture periods of high network use from different perspectives, such as peak load conditions, high power flows across interfaces, and between nonadjacent regions. See Appendix A.6 for an outline of periods selected as snapshots.

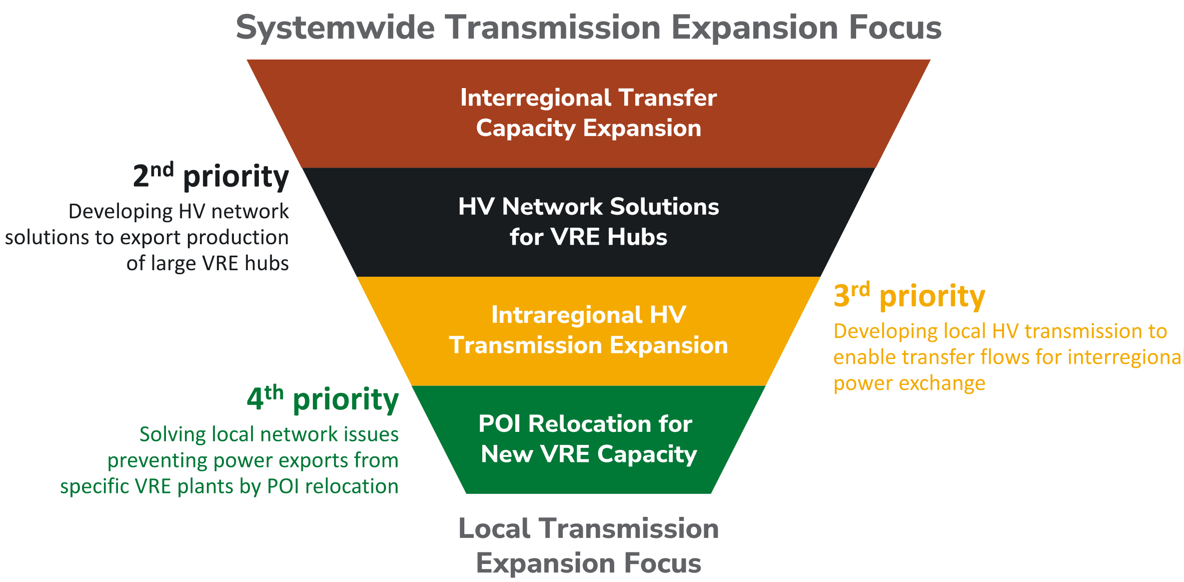


Figure 7. Prioritization of transmission expansion planning approach

Stage 3: Transmission expansion planning with selected single transmission network contingencies

Stage 3 of the Z2N process applies similar logic to that of Stage 2 but with the system intact linear power flow analysis being replaced by selected single contingency linear-power-flow-based contingency analysis. Contingencies are defined as individual branch element outages,[27] which include the subset of branches that form tie-lines between transmission planning regions[28] plus all lines within a transmission planning region that directly connect to a tie-line ("first-degree neighbors") inclusive of any newly added tie-lines between regions (as shown in Figure 8).

The planning criteria applied in the final scenarios' CONUS expansion results are the monitoring of all branches greater than or equal to 220 kV, postcontingency overload threshold of 100% of emergency ratings ("Rate B") for lines not overloaded in the precontingency state, and postcontingency loading change greater than 30% (relative to the precontingency state) for lines already overloaded in the precontingency state.[29] In the earlier scenario results for the Western Interconnection (results shown in Section 4), the emergency rating is used for postcontingency flows. When this is not available,

[27] Analogous to P1 and P2 type contingencies defined in NERC TPL-001-5 (North American Electric Reliability Corporation [NERC] 2020).
[28] The regional boundaries between transmission planning regions and the underlying balancing authorities (BAs) in industry are slightly different from those used in the NTP Study. Chapter 2 maps the assumptions for the geographic bounds of the regions used throughout the NTP Study.
[29] In cases where a transmission line under the contingency list is modeled as a multisegment line or includes a tap point without any load or generator connected to it, the selected single contingency is modeled to include the tripping of all segments composing the model of the given single contingency. In other words, a single contingency is modeled by tripping multiple elements simultaneously. In cases where Rate B = Rate A or Rate B = 0 in datasets, the postcontingency threshold is set to a default of 120% of Rate A (135% for earlier scenario analyses).

135% of normal rating is used. Because all branch constraints for branches 230 kV and above are enforced, no additional threshold is provided for precontingency overloaded branches. Decisions on expanding the network following the linear (DC) contingency analysis are based on consistent and/or widespread network overloads.

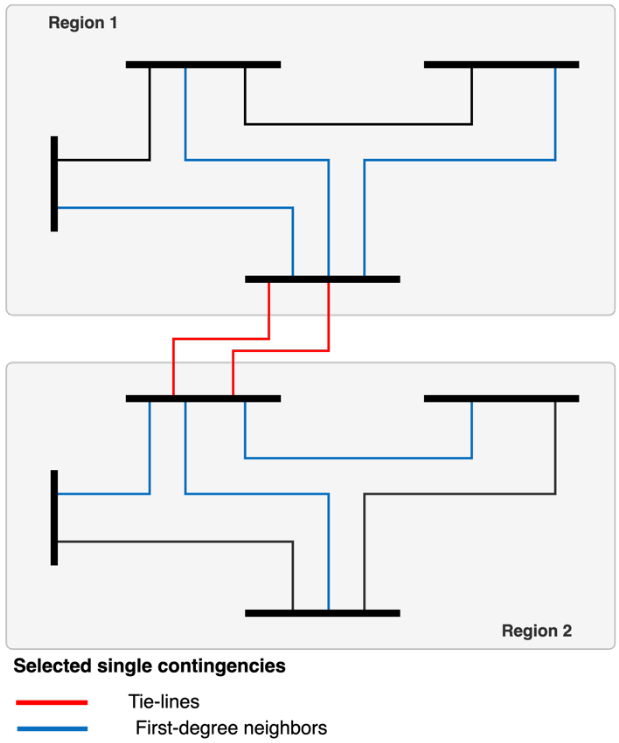
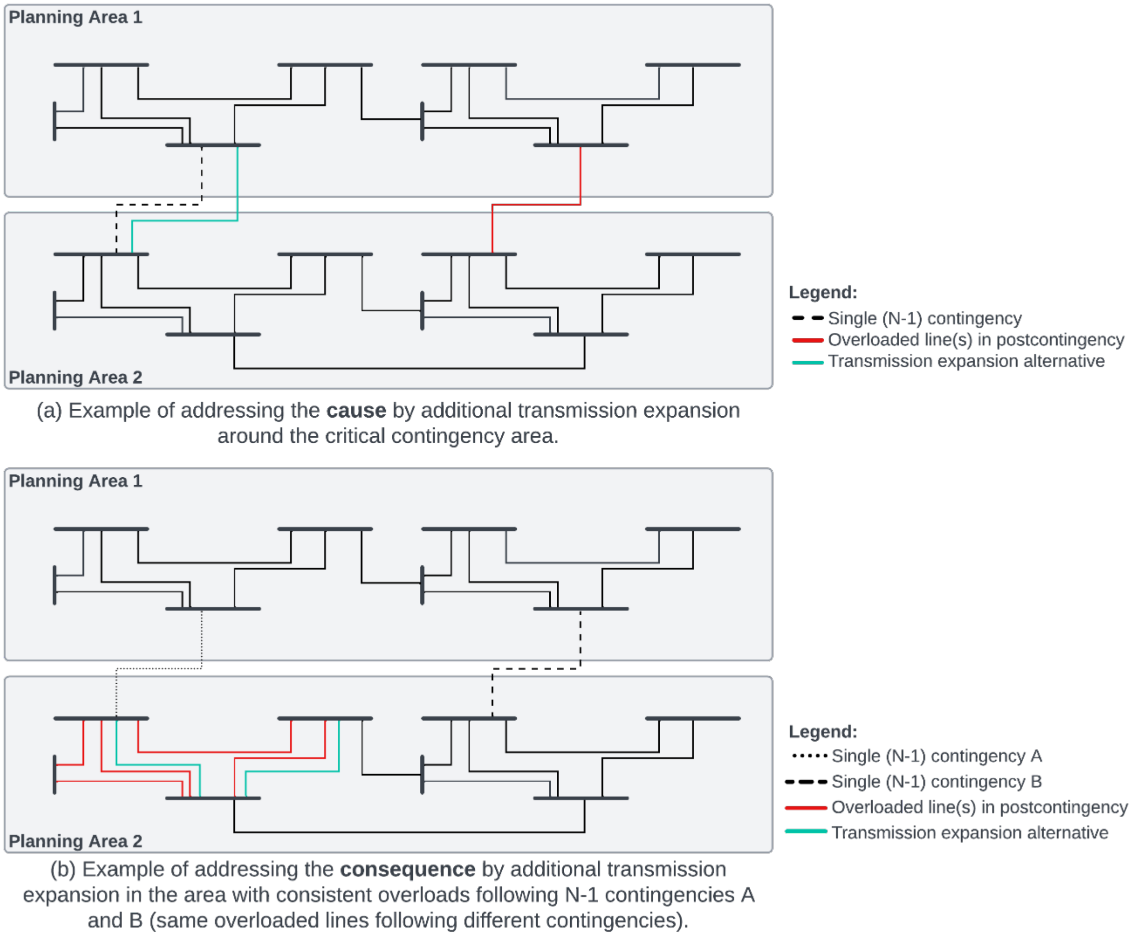


Figure 8. Illustration of single contingency definition for Stage 3 of zonal-to-nodal process

The selected single contingencies that comprise the contingency analysis are composed of tie-lines (red) and first-degree neighbors (blue).

Additional network expansions following the DC contingency analysis results are based on the principles depicted in Figure 9. In situations where a given contingency causes consistent and widespread network overloads, transmission reinforcements around the given contingency are proposed (mitigation of the cause). In situations where a given network element(s) is consistently overloaded across multiple contingencies and/or multiple operating conditions, network reinforcement solutions around the impacted element(s) are proposed (mitigation of the consequences).



(a) Example of addressing the **cause** by additional transmission expansion around the critical contingency area.

(b) Example of addressing the **consequence** by additional transmission expansion in the area with consistent overloads following N-1 contingencies A and B (same overloaded lines following different contingencies).

Figure 9. Illustration of mitigation of causes and consequences during contingency analysis

The study team performed contingency analysis on all existing and new interregional tie-lines as illustrated in Figure 8 and Figure 9. The contingency analysis is intended as a screen to address large interregional contingency risk considering some ties (500 kV and 765 kV in particular) have the potential to carry large amounts of power—on the order of 3000–5000 MW. However, the contingency analysis is not a comprehensive intraregional contingency assessment, so further analysis of new transmission expansions would be necessary when moving toward detailed network design stages, which is beyond the scope of the NTP Study.[30]

2.4 Transmission Planning Feedback to Capacity Expansion

The NTP Study approach included a feedback loop between zonal ReEDS capacity expansion findings and downstream nodal models to capture key learnings from initial capacity expansion findings and resulting downstream nodal model findings, illustrated in Figure 10. During the initial modeling for the NTP Study, the team had several rounds

[30] The results for Section 4 use a variation of the contingency method illustrated here. See Appendix A.7 for an explanation of this method, which was applied to the Western Interconnection earlier scenarios.

of scenarios that were used to refine these multimodel linkages and feedback constraints to ReEDS based on the buildout of nodal models. This feedback mainly focused on the following:

1. Improving the spatial distribution of wind and solar resources
2. Constraining maximum interzonal transmission buildout capacities.

For Item 1, the study team recognized that regions with large interregional transmission would in some cases require substantial intraregional network strengthening to accommodate large transfers to other regions. The result of the feedback is an improved representation of spur and reinforcement costs in the ReEDS final NTP Study scenarios, which is described further in Chapter 2. As an indirect effect of this improvement, concentrating large amounts of generation and transmission infrastructure in small geographical footprints is lessened.

For Item 2, the feasibility of certain high-capacity corridors in the earlier rounds of zonal capacity expansion modeling results was flagged by TRC members and the study team as being difficult to implement. In developing transmission portfolios of these corridors in the Z2N translations, several technical challenges were revealed with respect to the amount of transmission capacity that could be practically realized between ReEDS regions (both spatially and electrically). As a result, an upper bound of 30 gigawatts (GW) of maximum transmission buildout across a given corridor was set for the final round of ReEDS scenarios.

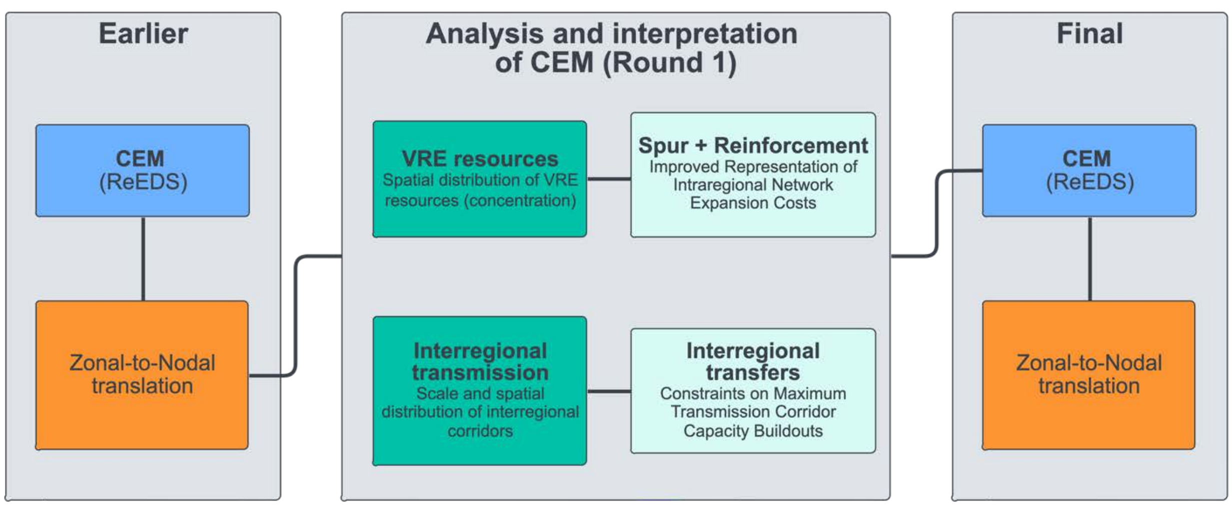


Figure 10. Overview of transmission expansion feedback between zonal and nodal modeling domains

2.5 Scenarios for Nodal Transmission Plans and Production Cost Modeling

A subset of the 96 scenarios from ReEDS was chosen to be translated into nodal scenarios because of the complexity of working with large nodal power system models. Therefore, the study team narrowed down the scenarios with the intent to understand distinct transmission expansion learnings between each scenario, interest from the TRC, and feasibility of implementation. The study team opted for scenarios situated between the extremes of cost and demand projections as well as technology advancements. In addition, though the scenarios from ReEDS extend to 2050, the nodal models for this chapter are focused on 2035 to understand the more immediate implementation challenges. Table 5 summarizes the three scenarios for the development of nodal interregional transmission expansion.

Table 5. Summary of Scenarios for Zonal-to-Nodal Translation

Dimension	Limited	AC	MT-HVDC
Transmission framework[1]	AC expansion within transmission planning regions	AC expansion within interconnects	HVDC expansion across interconnects (+AC within transmission planning regions)
Model year		2035	
Annual electricity demand		Mid Demand[1] CONUS: 5620 TWh (916 GW) Western Interconnection: 1097 TWh (186 GW) ERCOT: 509 TWh (93 GW) Eastern Interconnection: 4014 TWh (665 GW]	
CO_2 emissions target		CONUS: 90% reduction by 2035 (relative to 2005)	

[1] See Chapter 2 for further details.

CO2 = carbon dioxide; AC = alternating current; TWh = terawatt-hour; GW = gigawatt; HVDC = high-voltage direct current

A summary of the interregional transmission expansion from the ReEDS zonal scenarios is shown in Figure 11 (aggregated to the subtransmission planning region level).[31] Maps of the results of zonal transmission expansion from ReEDS for the three scenarios are shown in Appendix B.4. Large transmission planning regions are split into meaningful subregions for transmission expansion, analysis, and insights from zonal ReEDS findings.

[31] All results in this chapter from the zonal ReEDS capacity expansion are analyzed in greater detail in Chapter 2. Chapter 2 highlights more 2050 results, although Appendix B of Chapter 2 provides an overview of the 2035 results.

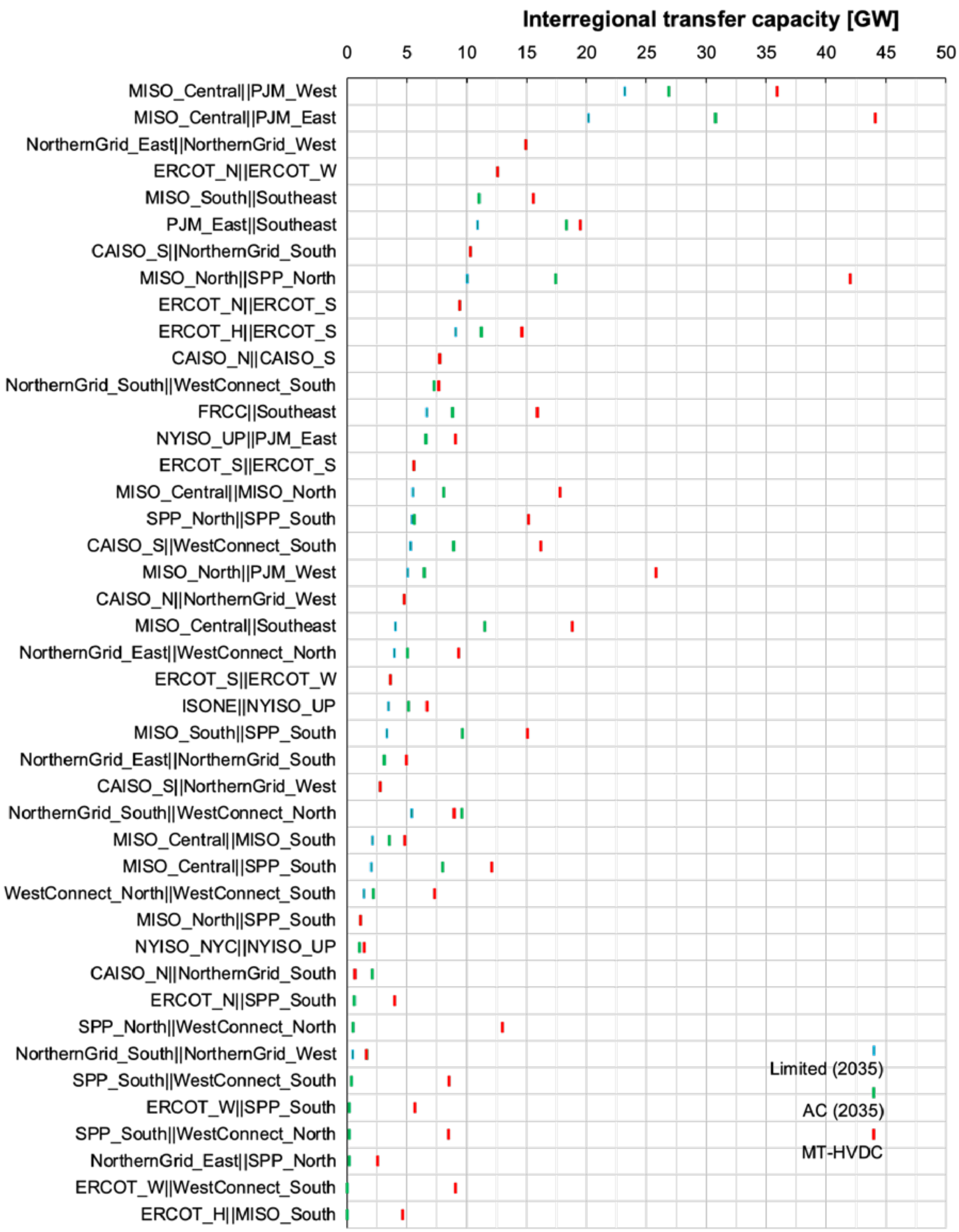


Figure 11. Interregional transfer capacity from ReEDS zonal scenarios used for nodal Z2N scenarios

2.6 Economic Analysis of the Western Interconnection (earlier scenario results)

This economic analysis evaluates the avoided costs and disaggregates economic benefits among different network stakeholders of the nodal scenarios from the earlier ReEDS expansions. The Limited scenario is used as a reference to estimate the avoided cost of the AC and MT-HVDC cases. This study uses avoided costs as the metric to estimate the economic benefits of transmission capital, generation capital, and operation. Avoided cost is an accurate measure of the economic benefits when load demand is constant across the scenarios analyzed (Hogan 2018; Mezősi and Szabó 2016). See Appendix D.4 for a brief discussion of prior studies that have estimated the economic benefits of transmission. The production cost modeling uses the same demand as an input to the scenarios modeled, so this condition is met for the scenarios in this study. The overall avoided costs are estimated as the sum of the capital and operational avoided costs after they have been annualized to enable comparison of avoided costs that occur over different time horizons. This section discusses the methodology of how the capital costs of generation and transmission were developed. The section also describes the methodology for estimating the total avoided costs using annualized values as well as the methodology used to disaggregate the avoided costs as benefits among different network users. Disaggregating the benefits can help understand how the avoided costs enabled by interregional transmission could economically benefit different stakeholders, providing information to the multiple groups that must collaborate to build transmission infrastructure.

2.6.1 Transmission capital cost methodology

Transmission costs are based on the transmission lines added to the GridView Production Cost Model by voltage class (230 kV, 345 kV, and 500 kV) according to the methodology introduced in the previous sections. The study team used the WECC Transmission Calculator (Pletka, Ryan et al. 2014) that was updated by E3 in 2019 (E3 2019) to calculate the capital costs for transmission. New generation is added to viable POIs at 230 kV and above. If no POI is sufficiently close,[32] a new POI is created. As such, a significant portion of what might be called “spur lines” in the capacity expansion model is explicitly modeled in the nodal builds. The WECC Calculator multipliers for land ownership and terrain were used to estimate the cost of added transmission along with the costs associated with the allowance for funds used during construction (AFUDC).[33] Appendix D.3 provides more detail on the land ownership and terrain multipliers.

2.6.2 Generation capital cost methodology

Generation capital costs are taken directly from ReEDS outputs from earlier scenarios for 2022–2034 for Limited, AC, and MT-HVDC. The capital cost inputs to ReEDS for each generation type are taken from the Annual Technology Baseline (ATB)

[32] For all wind and solar locations in the AC and Limited (Lim) scenarios, the average distance to their POIs is 17 miles.

[33] AFUDC is the cost of money invested or borrowed during construction that must be accounted for in the total costs of construction.

database (National Renewable Energy Laboratory 2023). The values are in 2004$ and were escalated to 2018$ using the Consumer Price Index to match year dollars in GridView. Costs are not split between the resource types, meaning all generation capital costs are aggregated to a single dollar number.

2.6.3 Operating cost economic metrics methodology

The total economic benefits are estimated as the avoided cost for grid operation, across the different transmission topologies. The costs modeled in GridView include fuel, startup, shutdown, and other variable operating costs. The relative avoided costs of the AC and MT-HVDC transmission topologies can be calculated by subtracting the total cost of the AC and MT-HVDC scenarios from the Limited scenario:

$$\text{Avoided Cost}_i = \text{Cost}_{Lim} - \text{Costs}_\text{i} \; i \in \{\text{AC}, \text{MT-HVDC}\}.$$

The study team estimated the subsidy payments for the investment tax credit (ITC) and production tax credit (PTC). The ITC applies a 30% credit to generation capital costs for solar plants[34] (U.S. Department of Energy [DOE] 2022a) and the PTC applies a $26/MWh credit to wind generation (DOE 2022b).

2.6.4 Net annualized avoided cost methodology

To account for the difference in timing and useful lifetime of the different capital investments, the study team annualized the avoided transmission capital costs and the avoided generation capital costs. The net annual avoided costs are equal to the sum of the annual avoided operation costs and the annualized avoided capital costs. When net annualized avoided costs are greater than zero, the scenario should be considered to have positive overall avoided costs. The following formula is used to compute the annualized cost:

$$Annualized\ Cost = C \times \frac{r(1+r)^n}{(1+r)^n - 1}$$

Where *r* is the discount rate and *n* is the assumed lifetime of the infrastructure. The study team used discount rates of 3% and 5% to show the net annualized value across a range of discount rates. The assumed life of transmission capital is 40 years, and the assumed life of generation capital is 20 years. Annualized value is also sometimes called the annuity value and can be interpreted as the annual payment required over the lifetime of an investment to be equivalent to the net present value of an investment paid today as a lump sum (Becker 2022).

2.6.5 Benefit disaggregation and calculating the annualized net present value

In this chapter, the study team disaggregated system benefits according to different network users, such as the consumers, the producers, and transporters. For the grid, the generators are the producers, transmission owners are the transportation entity, and power purchasers are the consumers. The NTP Study does not model the final stage of

[34] These use round 1 ReEDS results where solar is assumed to take the ITC. This does differ from round 2 results where solar takes the PTC.

the grid where the power purchasers distribute load to the end consumers through the ratemaking process. This ratemaking process varies across states and utilities, but in general costs (and avoided costs) are passed on to consumers through this process.

Disaggregating benefits according to network users provides additional information that could enable more efficient planning to utilities, independent system operators (ISOs), and system operators. For a single decision maker, such as a vertically integrated utility, the optimal transmission topology would minimize system cost required to serve load demand subject to regulatory requirements. In contrast, in a pure market setting, the optimal transmission topology would be consistent with the market equilibrium where market participants (network users) take prices as given (Hogan 2018). The electric grid is a hybrid of these two structures. Many regions are served by a single utility; however, interregional transmission typically requires collaboration across multiple utilities, ISOs, and local stakeholder groups. In addition, wholesale electricity markets are becoming more prevalent, and the frequency of power purchase agreements (PPAs) between generators and utilities or consumers is increasing. Understanding the relative benefits to different network users can help achieve a broader consensus among network users that must cooperate to build interregional transmission (Kristiansen et al. 2018).

A critical component required to disaggregate economic benefits is an estimate of the market price. Electricity price forecasts typically use historical data on electricity prices and other variables. This can result in high forecast error as the forecast progresses farther into the future and as other conditions change (Nowotarski and Weron 2018). The most common approach for estimating prices from PCM simulations is to use the locational marginal prices estimated by the model. However, the simulated LMPs estimate revenues that are insufficient for cost recovery for most generators in the model. The scenarios simulated the 2035 grid with significantly higher renewable penetration than at present, making a forecast using the simulated locational marginal prices, or present and historical prices unreliable. To alleviate this issue, the study team assumed each generator receives its levelized cost of energy (LCOE) as its price, approximating the lower bound that the generators would need, on average, to attract investment financing. LCOE values were obtained from the ATB dataset for land-based wind, offshore wind, solar PV, geothermal, battery storage, and hydropower using moderate estimates, research and development (R&D) financials, and the year 2035. LCOE values were obtained from Lazard (2023) for nuclear, coal, and natural gas (Lazard 2023). This assumption models a generator operating under a PPA at a set price or a price that is steadily escalating with inflation over time. LCOE represents the minimum average price that a generator project requires to attract capital investment (Lai and McCulloch 2017). This assumption ensures the modeled price is sufficient for investment in the modeled generation capacity to occur. Of note, the disaggregation of benefits and the modeling assumptions for prices do not affect the total benefit estimates. Changes in prices will cause a transfer of benefits between generators and power purchasers but does not affect the total benefits.

Generator benefits are estimated using the profits (revenue minus cost) to the generators. The generator costs were obtained from the GridView simulations. Generator revenue is estimated by multiplying the price (LCOE) by the dispatched generation—that is, generators are not compensated for generation curtailed in the model. Because LCOE is the minimum average price required, this estimate of generator benefits represents a lower bound on the annual generator benefits that would be feasible to serve the required load. The total benefits to generators are computed by summing over all generators using the following equation:

$$Benefit_{generators} = \sum_{j=1}^{J} Benefit_j = \sum_{j=1}^{J} LCOE_j \times Generation_j - Cost_j$$

Transmission owner benefits are estimated as the annual revenue given to the transmission owners. In practice, transmission owners are remunerated through a variety of payment mechanisms that vary across jurisdictions. The study team did not model a formal transmission sale market, so the team used the annual revenue requirement for the transmission capital. The annual revenue requirement is the amount of revenue that a capital investment requires to attract the initial financial capital needed to build the infrastructure (Becker 2022). This ensures the transmission owners receive sufficient revenue to build the transmission capital in the modeled scenarios. Similar to using LCOE to model generator revenue, this assumption represents a lower bound on the annual benefit for transmission owners. Annual revenue requirements are computed using the following equation:

$$Benefit_{transmission\ owners} = Transmission\ Capital\ Cost \times \frac{r(1+r)^n}{(1+r)^n - 1}$$

Where r is the discount rate and n is the expected lifetime of the infrastructure. The study team used $r = 5\%$ and $n = 40$ years for transmission capital.

The study team assumed the power purchaser benefits are equal to the total load benefits minus total load payments. The total load benefits represent the overall economic benefit to end consumers from all electricity uses. The total load benefit is a large quantity that is outside the scope of this study to estimate. When the total load benefit is equal across the scenarios being compared, taking the difference to estimate the relative benefits of the scenarios results in the total benefit term exactly to zero. When this holds, the relative power purchaser benefit simplifies to the avoided cost in load payments. The critical assumption required for the total load benefit to be equal across scenarios is that load demand is the same across the cases being compared, and this assumption is held true within the production cost modeling input assumptions. The power purchaser payment is the sum of payments to generators and payments to transmission owners.

The final stakeholder considered are the taxpayers. The PTC subsidy is paid for broadly by the taxpayer base. This study does not model any formal tax policy regarding tax brackets and assumes taxes are paid when the subsidies are paid. This avoids assumptions about whether the subsidies are paid through government debt or some other mechanism. This simplifies the analysis so the taxpayer benefit is the avoided cost of subsidy payments. If tax payments increase between scenarios that are compared, this manifests as a negative benefit to the taxpayers.

The annual benefit for each network user for each scenario is the difference between the AC and MT-HVDC transmission scenarios compared to the Limited scenarios; i.e., for each network user *j,* their benefit is calculating using:

$$\mathrm{Benefit}_{i,j} = \mathrm{Cost}_{Lim,j} - \mathrm{Costs}_{\mathrm{i,j}} \; i \in \{\mathrm{AC}, \mathrm{MT\text{-}HVDC}\}.$$

3 Contiguous U.S. Results for Nodal Scenarios

This section presents the study team's results of the nodal transmission portfolios for the contiguous United States for the model year 2035, with emphasis on the resulting transmission plans and the operations of these systems.[35] The study team finds there are several transmission portfolios that can meet the hourly balancing needs of a high renewable energy scenario and, with increased interregional transmission, imports and exports can have large impacts on some regions—resulting in exchanges that exceed the total demand of these regions.

3.1 A Range of Transmission Topologies Enables High Levels of Decarbonization

The Z2N translation of ReEDS scenarios demonstrates how a range of transmission topologies and technologies can be used to meet long-term resource changes. This is demonstrated in three scenarios modeled at a nodal level—Limited, AC, and MT-HVDC (and summarized in Table 6 and Table 7).[36] Transmission provides benefits for reaching high levels of decarbonization in a country with substantial amounts of regional diversity in generation resources and across scenarios that analyzed a range of strategies for system growth, transmission topologies, and technology choices. The three nodal scenarios demonstrate interregional or intraregional work in tandem to enable power to move around the country and substantial amounts of both types of transmission are seen in the transmission expansions.

In the Limited scenario, transmission is maximized at the regional level, building on existing high-voltage alternating current (HVAC) networks in the regions. The AC scenario portfolios find local transmission is still important and in need of expansion, but interregional transmission plays a much bigger role—especially in areas of the country where large amounts of new resources are added or where existing HV transmission networks are less developed and interconnected. The need for large expansions of interregional transmission in some regions necessitates voltage overlays (Southwest Power Pool [SPP], MISO, WestConnect) but, in many instances, expansions using existing voltage levels is sufficient.

The MT-HVDC scenario is a very different paradigm compared to systems dominated by HVAC transmission expansion. The HVDC expansions are all long-distance and connecting between neighboring regions, or farther. In addition, the HVDC is largely embedded within AC networks that do not have any experience with HVDC, signifying new operational frameworks would need to be created to handle a very different operating regime. Some regions—such as SPP, MISO, WestConnect, and ERCOT—have substantial enough buildouts of HVDC that it could play a large role in balancing supply and demand. Considering the scale of HVDC expansion envisioned in this study,

[35] All results in Section 3 are from the final ReEDS scenarios, which are inclusive of Inflation Reduction Act impacts and other advances in the ReEDS model. See Chapter 2 for more details on the final ReEDS scenarios.

[36] Further detailed findings from each scenario are provided in Figure B-45, Figure B-46, and Figure B-47 in Appendix B.4.

efforts toward technological standardization and institutional coordination relative to existing practices would be necessary.

The following sections explore the diversity of network portfolios and resulting key messages identified for the three scenarios derived from the application of the Z2N methods and sets of tools described in Section 2. These takeaways are organized into disaggregation (demand, generation, storage), transmission expansion and system operations (focused on transmission) to underscore how transmission growth enables multiple pathways and can support regionally specific solutions for transformative futures.

Table 6. Summary of Common Themes Across Nodal Scenarios

Common Themes Across Nodal Scenarios (Limited, AC, MT-HVDC)
- Reinforcement (single-circuit to double-circuit) and/or reconductoring of existing transmission lines occurs in most regions. - Increased meshing of existing networks improves contingency performance and collects large amounts of renewable energy from remote parts of existing networks. - Development of intraregional transmission networks primarily uses existing voltage levels but with state-of-the-art high-capacity tower and conductor configurations.[37] - Reconductoring is a possible solution for some areas where single-circuit to double-circuit expansions are undertaken and part of the transmission network is reaching end of life and will need to undergo modernization. - Significant amounts of new renewable energy and storage in parts of the country where there is little to no HV/EHV transmission network infrastructure creates conditions where specific network topologies to collect resources at HV levels could be a good solution and were implemented in these transmission portfolios. - Although explicit transmission technology choices and expansion constraints define each transmission portfolio, if further HVDC is implemented at scale, AC and HVDC transmission networks will need to coexist. This results in additional needs for coordination of flows between new AC and HVDC corridors, embedded HVDC corridors, and MT as well as meshed HVDC networks.

[37] With the implicit interregional focus of the NTP Study (characterized by the need for high-capacity interregional transfers across long distances), the use of high-capacity towers and conductor configurations was an exogenous decision in the modeling after confirming with technical stakeholders this was a valid path forward. It is possible in some corridors these configurations are not necessary or feasible.

Table 7. Summary of Differentiated Themes for Each Nodal Scenario

Differentiated Themes Across Nodal Scenarios		
Limited	**AC**	**MT-HVDC**
- Substantial amounts of HVAC transmission are expanded within transmission planning regions to enable integration of new VRE capacity usually located far from main load centers. - Intraregional transmission expansion using existing voltage levels for most regions provides sufficient enabling transfer capacity to move power to load centers within regions and to adjacent regions. - Further enabling intraregional expansion in some regions requires the introduction of new EHV voltage levels (voltage overlays), i.e., mostly shifting from 230 kV to 345 kV and 345 kV to 500 kV (minimal new voltage overlays to 765 kV). - Reinforcement and/or reconductoring of existing transmission lines can be a proxy for single-circuit to double-circuit expansions in specific areas (particularly where transmission networks are older).	- Definitive need for substantial amounts of new high-capacity, long-distance, EHV transmission for further connecting transmission planning regions. - Further expanding existing 765-kV AC networks (relative to 500-kV interregional expansions). - Contingency performance when further expanding 765-kV networks (as a large contingency) is important when designing transmission expansion portfolios, i.e., need for supporting existing and potentially new 230-kV, 345-kV, and 500-kV networks under contingency conditions. - In areas where 230-kV and/or 345-kV networks form the transmission grid, high-capacity 500-kV AC transmission seems a good option for expansion. Single-circuit to double-circuit or increased network meshing at existing voltage levels does not prove sufficient. - Considering the volumes of interregional flows, increased coordination between regions (for generation dispatching needs) is expected to operate future systems in the most economical manner while maintaining system reliability. - Series compensation of new EHV capacity for particularly long distances (e.g., Western Interconnection) is implicit in the transmission expansion solutions. However, this was not explored in detail and would need to be further investigated considering large amounts of inverter-based resources.	- HVDC expansion portfolios establish the starting points for MT and potentially meshed HVDC networks. Hence, the significant expansion of high-capacity, long-distance interregional HVDC transmission is based on bipolar, multiterminal/meshed-ready HVDC technologies. - Expanded HVDC performs the role of bulk interregional power transfers whereas HV and EHV embedded AC transmission (existing and in some cases expanded) fulfills a supplementary role in interregional transfers while simultaneously supporting contingency performance. - Large amounts of intraregional HVAC networks are expanded (with similar voltage levels as currently being used/planned) to enable infeed to and from HVDC converter stations. - High coordination levels between regions and across interconnects is expected to operate future systems in the most economical manner (for generation dispatch and HVDC dispatch) while maintaining system reliability.

Across the nodal scenarios, the expansion of transmission is always substantial. The Limited scenario has the least amount of expansion in all metrics—total circuit-miles, thermal capacity, and the combination of these calculated as terawatt-miles (TW-miles) of transmission. However, the differences between the two accelerated transmission scenarios—AC and MT-HVDC—shifts depending on the metric considered. The circuit-miles are relatively close (~73,000 miles and ~69,800 miles, respectively) whereas thermal capacity or TW-miles is significantly less for the MT-HVDC scenario, primarily because in the MT-HVDC scenario there are relatively long lines that make the miles metric closer. But the HVAC transmission buildout in the AC scenario is substantially more in the combined capacity and distance metric because the scenario includes more shorter-distance HVAC expansions (178 TW-miles in the AC; 80 TW-miles in the MT-HVDC). Further details on these findings are provided in Appendix B.4.

3.2 Translating Zonal Scenarios to Nodal Network Scenarios

3.2.1 Scale and dispersion of new resources is unprecedented

Based on ReEDS outputs, the scale and geographic dispersion of new generation and storage resources that must be integrated into the U.S. grid in the NTP Study nodal scenarios is unprecedented. Figure 12 shows the total installed capacity by interconnect[38] for the nodal scenarios; Figure 13, Figure 14, and Figure 15 show the nodal POIs (allocation of capacity to specific substations) for the three scenarios after the disaggregation stage of the Z2N process.

The geographical dispersion and scale of new resources are the primary drivers of resulting transmission network expansion portfolios. The scenarios that allow for interregional transmission expansion—AC and MT-HVDC—build more capacity and hence have a substantially larger number of POIs and larger-capacity POIs (larger HV network injections), especially in the middle of the country where large amounts of land-based wind and solar PV are deployed. The MT-HVDC scenario is the least-cost electricity system plan for the three scenarios, followed by the AC and then the Limited scenario.[39] Savings in the MT-HVDC come in the form of reduced generation capital and storage capital costs followed by reductions in fuel costs.

[38] Further details of the installed capacity by transmission planning region and interconnection as well as CONUS-wide for each scenario are provided in Appendix B.4.

[39] Electricity system costs of these scenarios as well as their relative differences in quantum and composition refer to the results from the zonal scenario analysis in Chapter 2.

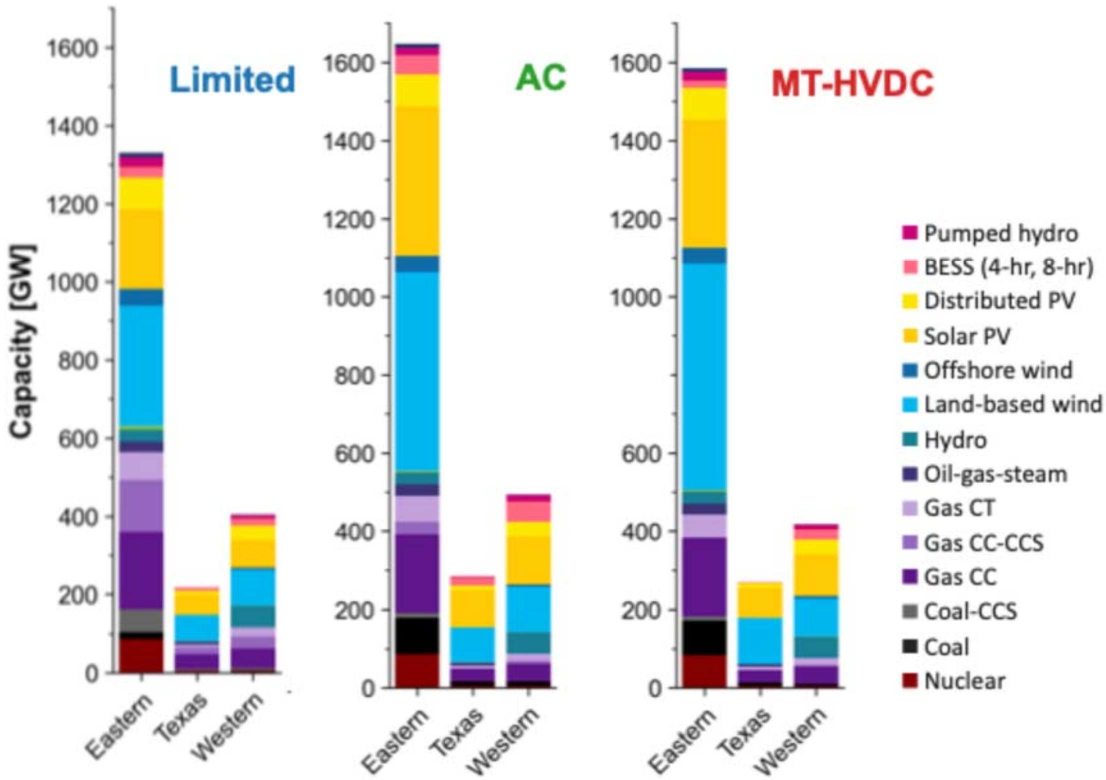


Figure 12. Generation and storage capacity for final nodal scenarios

The Limited scenario exhibits the least amount of installed capacity mostly because it includes the least amount of land-based wind and solar PV (465 GW and 453 GW, respectively) whereas a large amount of existing and new gas-fired and coal-fired capacity are retrofitted for coal capture and storage (CCS) operations (~182 GW and ~70 GW, respectively). As a reminder, the lower level of total installed capacity in this scenario is driven by capital costs for retrofits and new capacity as well as fuel (and to a lesser extent by operation and maintenance cost differences).[40] This is less evident in the AC and MT-HVDC scenarios where existing coal and gas capacity remains online and a smaller proportion is retrofitted for CCS operations (12–13 GW and 5–40 GW, respectively). There is 64 GW of battery energy storage system (BESS) capacity installed in this scenario, which is a substantial ramp-up from what is currently installed across CONUS but is substantively less than the AC scenario.

The AC scenario with the ability to expand interregional transmission via HVAC technologies (within the same interconnection) shows a significantly larger expansion of land-based wind and solar PV capacity (714 GW and 730 GW, respectively) and fewer CCS retrofits of fossil generation capacity (coal and gas). Much of the wind capacity is developed in the central wind belt of the country—in the Midwest (MISO region), along the Great Plains (SPP region), in parts of the Northeast and Rocky Mountains

[40] See Chapter 2, Section 3 for further details. Maps summarizing the zonal transmission expansion for the three nodal scenarios are presented in Chapter 2 but are also provided for reference in Appendix B.4.

(NorthernGrid and WestConnect regions), and in west Texas (ERCOT West). For solar PV, a large amount of capacity is concentrated in the Southeast (Southeastern Electric Reliability Council and Southeastern Regional Transmission Planning [SERTP] regions), parts of ERCOT, and the Desert Southwest (WestConnect region). There is ~130 GW of BESS capacity installed in the AC scenario (almost twice as in the Limited scenario).

The MT-HVDC scenario—with the ability to expand HVAC within interconnects and expand HVDC within interconnects and across seams—exhibits larger amounts of land-based wind (770 GW) and solar capacity (600 GW) compared to the Limited scenario but with a shift toward more land-based wind relative to solar PV capacity. As will be demonstrated further in the following sections, there is a distinct correlation of wind capacity expansion with increased interregional transmission. This is driven by the clear trade-offs between long-distance, high-capacity transmission expansion and wind resource expansion to move power from distant locations toward load centers.

All scenarios include offshore wind capacity of 47 GW being deployed by 2035 with most of this concentrated off the Atlantic coast (42 GW) and the remainder off the Pacific coast (~5 GW). These scenarios are based on assumed mandated offshore wind deployment targets set by state renewable portfolio standard policies. Offshore transmission network design options are not the focus of the NTP Study. Instead, land-based network expansion needs are established based on POIs correlated as much as possible with other similar efforts led by DOE (Brinkman et al. 2024).

Across the three nodal scenarios, a significant amount of new generation capacity is built in areas with very limited existing HV/EHV transmission capacity—that is, northern parts of SPP (Nebraska, South Dakota), MISO (Minnesota), Southern SPP (Oklahoma, Texas panhandle), eastern parts of NorthernGrid (Montana), and in the south of WestConnect (New Mexico). This necessitates significant development of HV/EHV transmission infrastructure because limited interregional HV/EHV transmission exists in these regions to enable a combination of collector networks of the many POIs (mostly VRE sources) or direct interconnection of large POIs to bulk transmission backbones for transfers to main load centers.

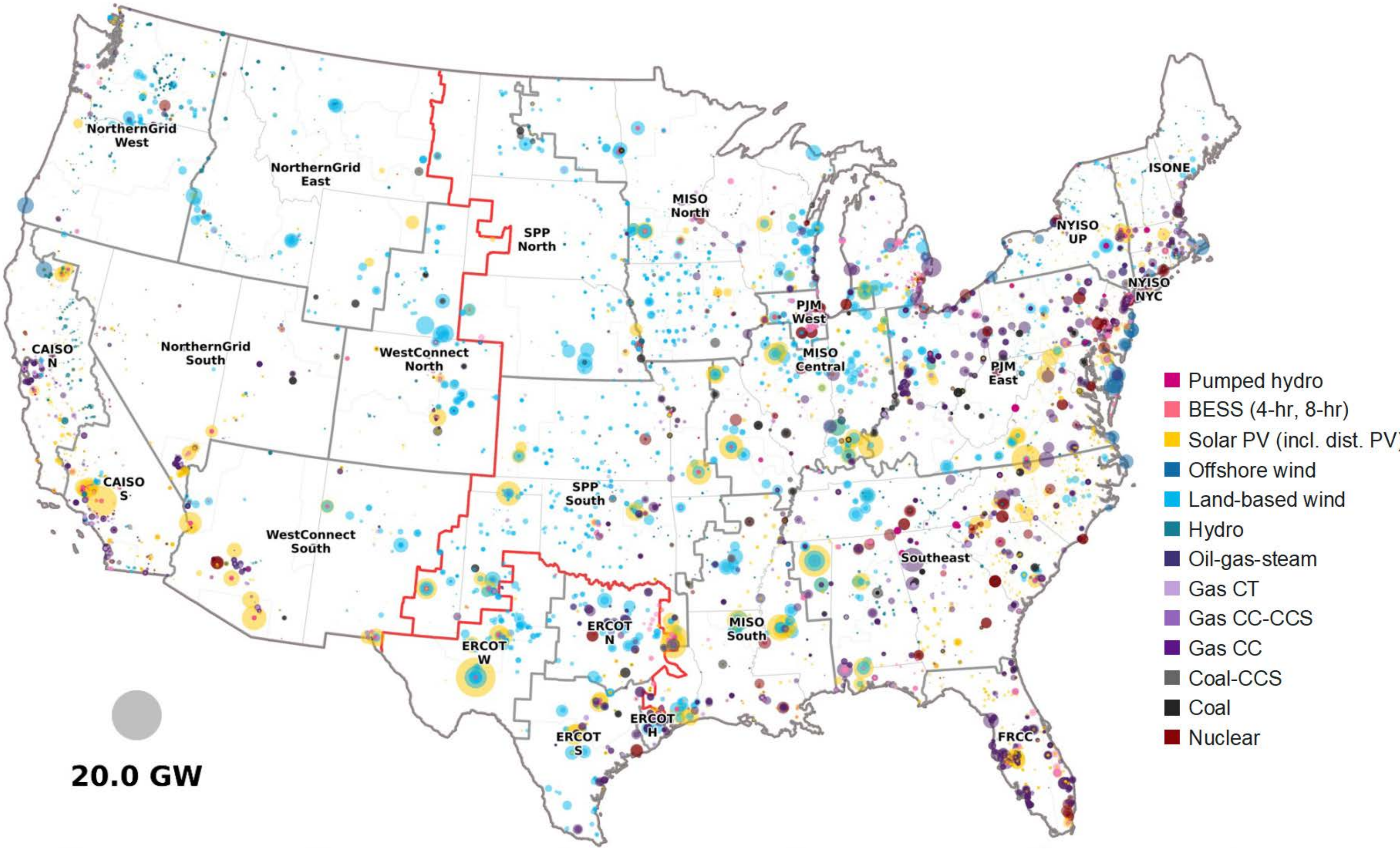


Figure 13. Nodal POIs, sized by capacity, for all generation types for the Limited scenario

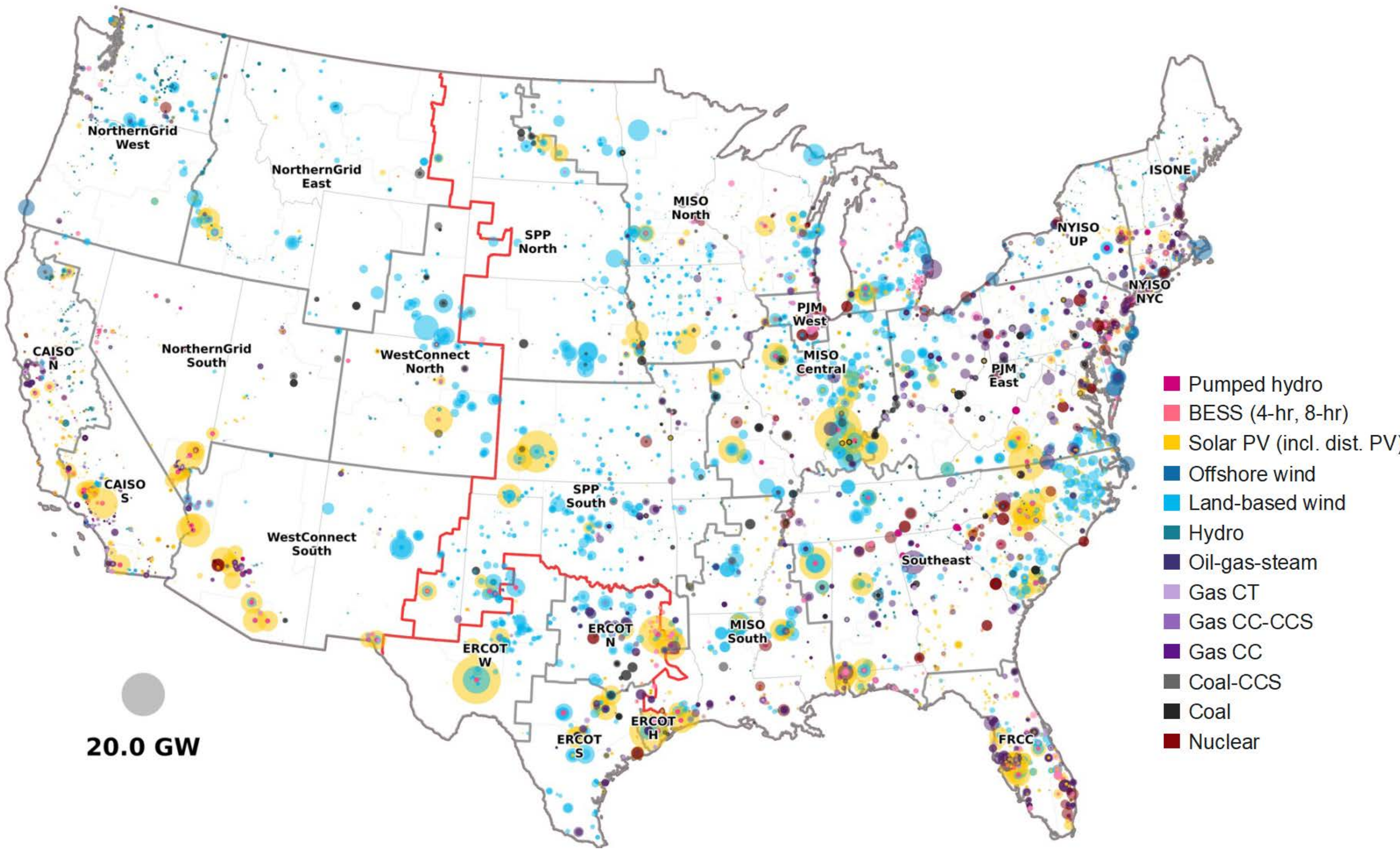


Figure 14. Nodal POIs, sized by capacity, for all generation types for the AC scenario

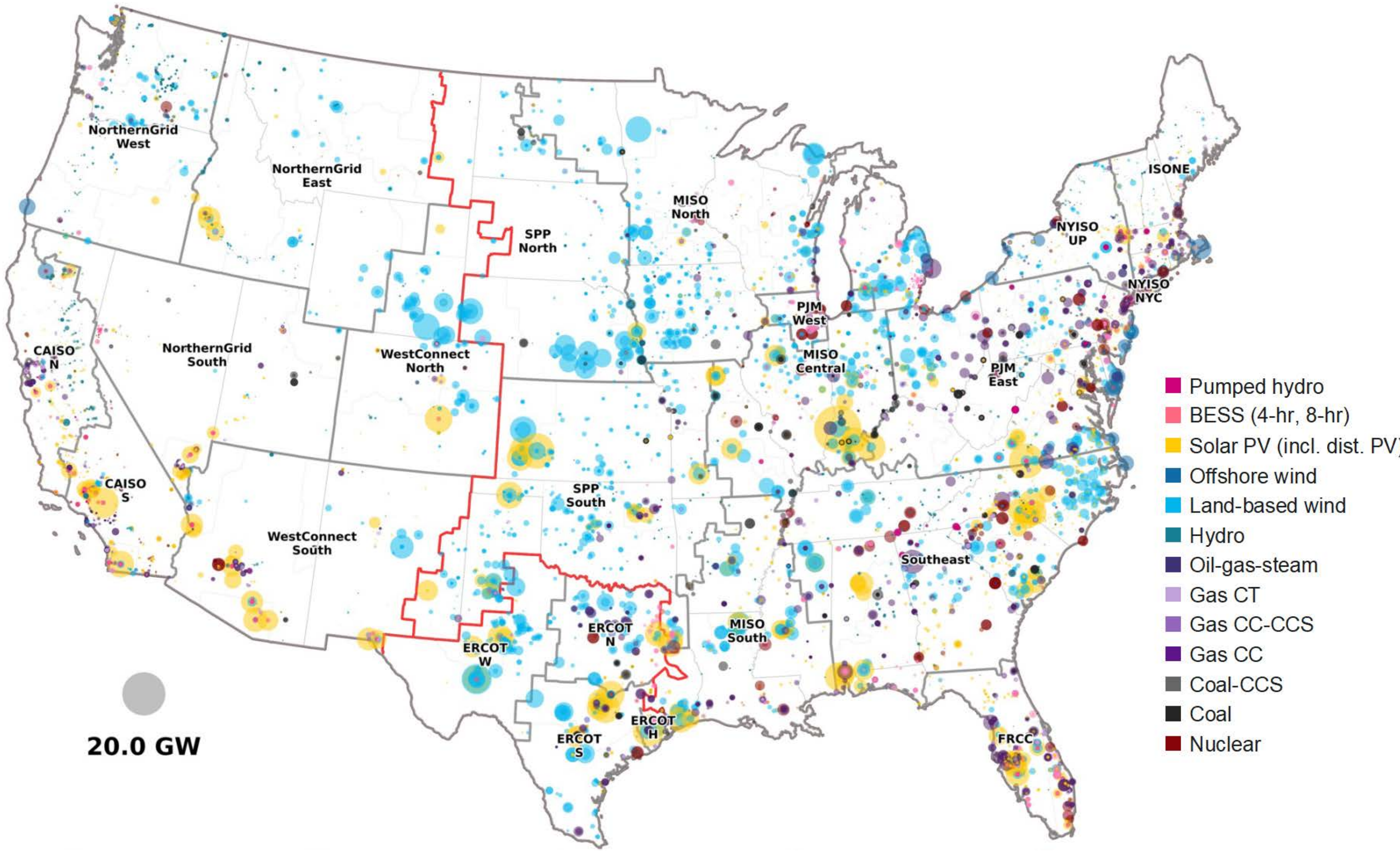


Figure 15. Nodal POIs, sized by capacity, for all generation types for the MT-HVDC scenario

3.2.2 Intraregional transmission needs are substantial, especially when interregional options are not available

In the Limited nodal scenario, additional transmission is 77 TW-miles by 2035,[41] which is 1.3 times the TW-miles of the existing industry planning cases.[42] New transmission consists of local interconnection for new resources at the bulk level as well as the enabling transit capacity to move power across nonadjacent regions to enable the integration of new capacity usually located farther from main load centers. Figure 16 shows the spatial mapping of the Limited scenario nodal transmission portfolio.[43]

Transmission portfolios predominantly include new circuits in parallel with existing circuits and some selected new intraregional paths via double-circuit additions to enable a nodal solution that meets the decarbonization objectives envisioned in this scenario. Hence, preexisting voltage levels within specific regions are generally maintained.

As shown in Figure 16, the intraregional nodal HVAC transmission needs in the Limited scenario are still substantial.[44] Local interconnection is most prevalent for new resources at the bulk level as well as the enabling transit capacity to move power across nonadjacent regions to enable the integration of new capacity usually located farther from the main load centers. These intraregional expansions are particularly notable in the southern parts of SPP, in PJM, and in northern parts of WestConnect.

[41] It is worth noting with a caveat that this nodal transmission portfolio expansion is higher than the corresponding ReEDS zonal expansion by 2035 (considering 1.83 TW-Miles/year constraint).
[42] Industry planning cases for this study are compiled based on planning cases for 2030-31 (Table 3).
[43] Table B-21, Table B-22, and Table B-23 in Appendix B.4 provide further detailed findings of the nodal transmission solutions for this scenario.
[44] A few instances of interregional transmission strengthening were required in the Limited scenario. This is for many reasons, such as the geographic zonal designations in ReEDS and the placement of new generation capacity (mostly wind or solar) in locations that are geographically in one zone but, when mapped to a nodal network model, could be closer to another zone and therefore cause congestion as a result of network impedances being represented (and not as a zonal transportation model as in ReEDS). In general, the intention of the ReEDS Limited scenario was maintained with very few interregional expansions.

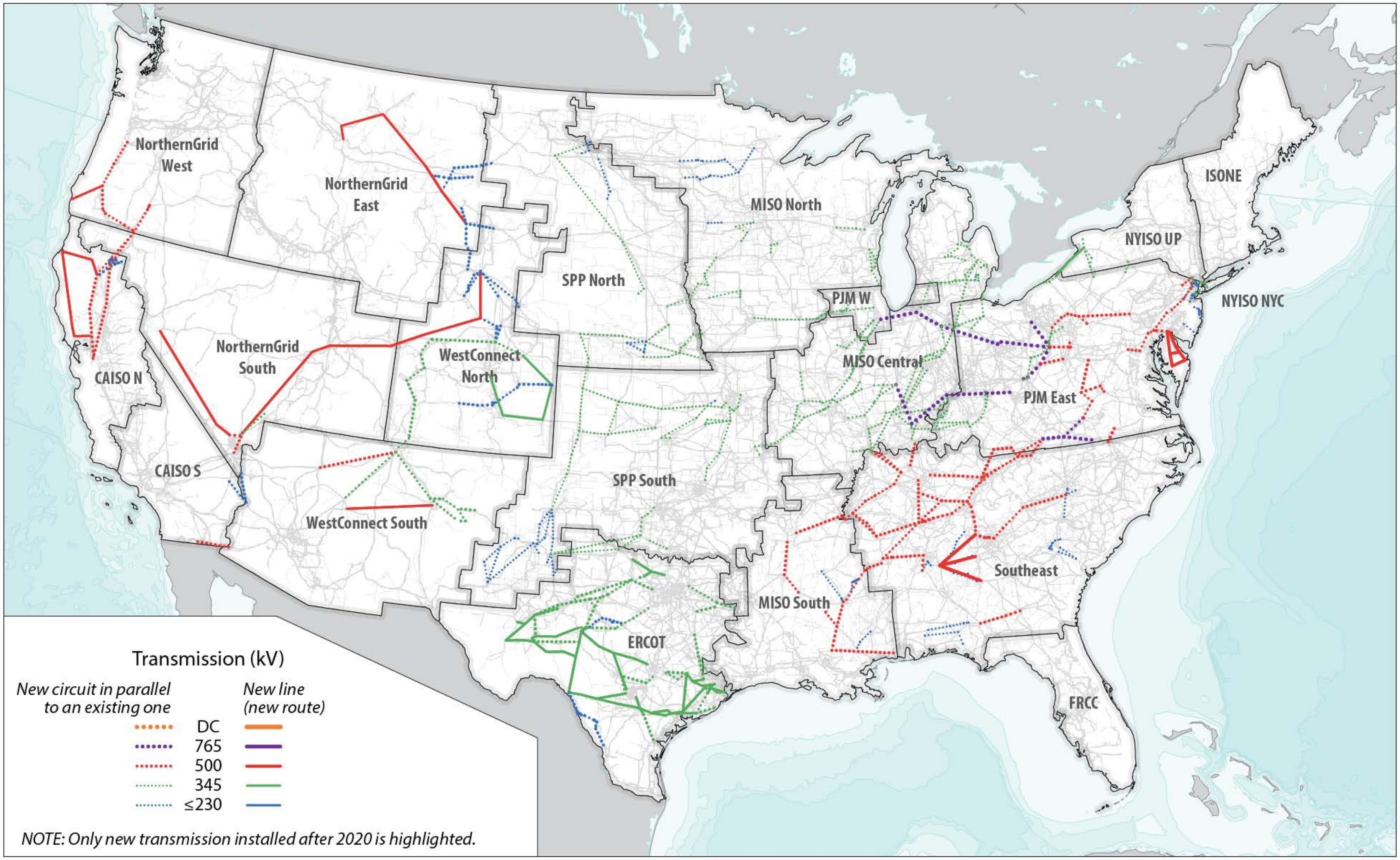


Figure 16. Nodal transmission expansion solution for the Limited scenario for model year 2035

3.2.3 Achieving high levels of interregional power exchanges using AC transmission technologies requires long-distance, high-capacity HV corridors combined with intraregional reinforcements

In the AC nodal scenario, where transmission infrastructure increased to 179 TW-miles (by 1.7 times the TW-miles by 2035 from the 2030/2031 industry planning cases), regional diversity of resources plays an important role when designing nodal transmission expansion portfolios. Figure 17 shows the spatial mapping of the AC nodal transmission expansion developed for the NTP Study.[45]

Transmission systems in much of the Southeast have a strong 500-kV backbone and underlying 230-kV networks (particularly in the eastern parts of the Southeast). These are used for the integration of predominantly new VRE generation capacity, including in the Carolinas and Georgia and stretching into Florida. Clusters also exist in Southern and Central Alabama as well as Tennessee. In the AC scenario, the expansion of the 500-kV network into the Midwest and farther west into the Plains enables the movement of large volumes of power across several interfaces north-south and west-east to load centers. This is enabled by existing 345-kV networks in the Midwest and Plains (MISO; SPP) that are further strengthened and link with the 500-kV networks in the Southeast.

In the Northeast, solutions for expansion are selected increases in transfer capacity on existing 345-kV networks. In PJM, there is strengthening of the existing 765-kV networks as well as creating further 500-kV links to the Southeast and along the Eastern Seaboard (increasing the capabilities for large north-south transfers across longer distances).

In the Western Interconnection, 500-kV overlays and new transfer paths at 500 kV in NorthernGrid and WestConnect help carry resources across long distances. Northern California Independent System Operator (CAISO) solutions include further 500 kV for interregional exchanges with NorthernGrid (Oregon) and to integrate West Coast offshore wind capacity.

In ERCOT, the existing 345-kV networks are strengthened by creating double-circuit 345-kV paths in existing single-circuit paths while creating new paths to bring wind and increased amounts of solar from western and northern Texas toward load centers in Dallas-Fort Worth, Austin, and Houston. There is not a strong case for new voltage overlays (toward 500 kV), and HVDC is precluded from this scenario as an expansion option.

When expanding interregionally, each region of the CONUS grid exhibits characteristics that influence network expansions. Significant amounts of new wind, solar PV, and storage in parts of the country where there is little to no HV/EHV transmission network infrastructure available opens the possibility for the design of specific network topologies to connect large concentrations of resources at HV levels to integrate into long-distance transmission corridors. This is a departure from the incremental

[45] Table B-23 in Appendix B.4 provides further detailed findings of the nodal transmission solutions for this scenario.

interconnection of relatively smaller VRE plants at subtransmission voltage levels (particularly solar PV and less for land-based wind). Areas where this is pertinent from the findings of the NTP Study are the far northern and far southern parts of SPP, WestConnect, parts of northern MISO, Florida Reliability Coordinating Council (FRCC), and western and northern parts of ERCOT.

The scale of interregional power exchanges that form part of the AC scenario requires some regions to develop high-capacity transmission infrastructure that enables transfer flows. More specifically, regions such as MISO act as a transfer zone between SPP and PJM whereas, similarly, the Southeast and PJM act as enablers of transfer flows for FRCC and the Northeast (Independent System Operator of New England [ISONE]/New York Independent System Operator [NYISO]), respectively.

The portfolios this section describes are a single implementation of interregional transmission. Hence, it is feasible a range of alternative transmission portfolios may provide similar technical performance where intraregional transmission needs could be further identified and refined and region-specific planning expertise could add value to the portfolios presented.

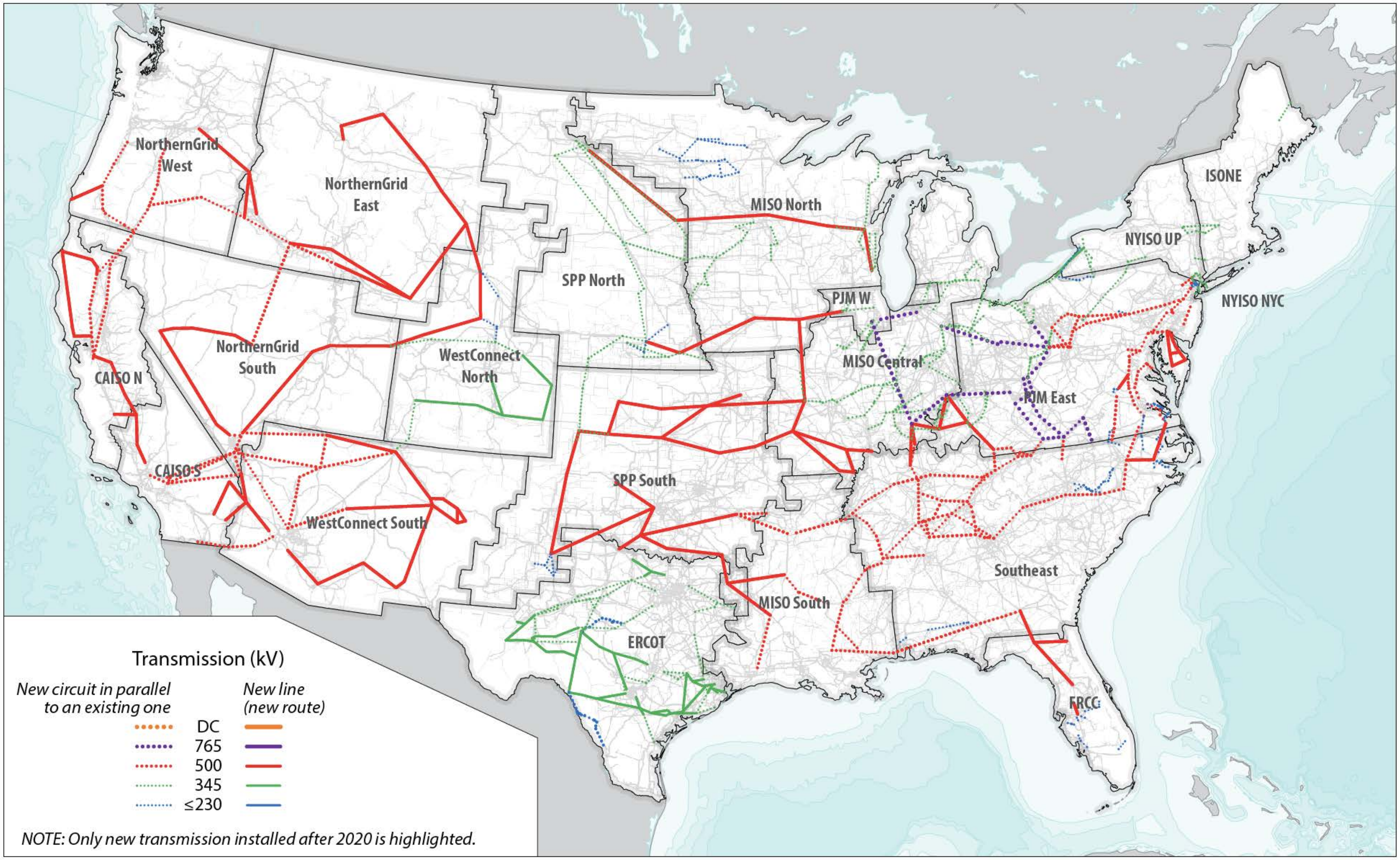


Figure 17. Nodal transmission expansion solution for the AC Scenario for the model year 2035

3.2.4 HVDC transmission buildout represents a paradigm shift and includes the adoption of technologies currently not widespread in the United States

The 2035 MT-HVDC scenario transmission design results in 128 TW-miles of additional transmission (a 1.5 times increase in TW-miles from the 2030/31 industry planning cases). This includes 48 TW-miles of HVDC and 80 TW-miles of HVAC. The total thermal capacity of HVDC expansion by 2035 is 156 GW.[46] The spatial mapping of the transmission solution is shown in Figure 18.[47]

The HVDC expansion enables substantial ties between the three U.S. interconnections, which currently have about 2.1 GW of transfer capacity (1.3 GW between the Eastern Interconnection and Western Interconnection and about 0.8 GW between the Eastern Interconnection and ERCOT). Seam-crossing capacity is 46 GW, deployed through 12- x 4-GW bipoles and a 1- x 2-GW monopole. Most of this is between the Eastern Interconnection and Western Interconnection (22 GW), further interconnecting WestConnect and SPP as well as NorthernGrid and SPP. The Eastern Interconnection and ERCOT capacity increases to 20 GW whereas the Western Interconnection and ERCOT are connected via two HVDC links totaling 8 GW. The expanded ties between ERCOT and the Western Interconnection are particularly highly used (~91%) and unidirectional (power flowing from ERCOT to the Western Interconnection). The expanded ties between Western Interconnection and Eastern Interconnection are bidirectional and have a utilization of ~40%.

Within the Western Interconnection, the beginnings of an MT and meshed HVDC network is realized at a nodal level via 20 GW of HVDC capacity (5 by 4 GW, excluding seam-crossing capacity), connecting large amounts of wind and solar PV in the southern parts of WestConnect to the northern parts of WestConnect and CAISO.

In the Eastern Interconnection, 90 GW of HVDC are built (18 by 4 GW and 1 by 2 GW). These HVDC links enable power to be moved from the predominantly wind-rich areas of northern SPP and MISO eastward, with the confluence in the central parts of MISO and PJM. The shifting of power between southern parts of SPP, southern MISO, and the Southeast is enabled via 16 GW (4 by 4 GW) of MT long-distance HVDC links where 8 GW of HVDC continues toward the FRCC region.

The development of the interregional HVDC transmission overlay that comprises the MT-HVDC scenario also requires significant development of intraregional HVAC networks to enable power infeed to and from HVDC converter stations. These can be seen in the map in Figure 18 where HVAC networks around HVDC terminals are expanded or increasingly meshed or, in some cases, new voltage overlays are developed to support the scale of infeed and/or export from HVDC converter stations. Hence, most of the HVAC expansion is via voltage levels already present in each region

[46] For the HVDC buildout process, the study team used discrete building blocks: 2 GW monopole or 4 GW bipole. These configurations were used as needed and terminated into strong areas of AC networks. Appendix A.5 provides further details on the HVDC transmission expansion philosophy.

[47] Table B-23 in Appendix B.4 provides further detailed findings of the nodal transmission solutions for this scenario.

but in some cases requires new voltage overlays. Examples of a large AC expansion is in WestConnect North, where the existing relatively weak 230-kV and 345-kV networks need strengthening. There are also significant changes to the underlying AC network in southern SPP, where a 500-kV expansion enables additional movement of power from SPP toward southern MISO.

The extent of HVDC transmission expansion in the MT-HVDC scenario combined with the underlying nodal AC transmission expansion has not yet been seen in industry plans in the United States (Johannes P. Pfeifenberger et al. 2023; Bloom, Azar, et al. 2021; Brown and Botterud 2021; Eric Larson et al. 2021; Christopher T. M. Clack et al. 2020; Bloom, Novacheck, et al. 2021) or internationally (European Network of Transmission System Operators for Electricity [ENTSO-E], n.d.; Terna spa, n.d.; National Grid ESO, n.d.; DNV 2024; CIGRE 2019, 775; MEd-TSO 2022; Empresa de Pesquisa Energética [EPE] 2023). Similarly, considering the level of buildout envisioned in the MT-HVDC scenario, features that could ease HVDC growth over the coming decades include the implementation of MT and meshed-ready technology deployments; common design principles and standardized HVDC voltage levels, communications protocols and technology configurations would also be helpful. These were generally assumed to exist in the MT-HVDC nodal scenario. Finally, the operational and institutional coordination necessary in MT-HVDC production cost modeling is beyond what is currently practiced between regions in the United States and may require new approaches to operations via increased coordination at various operational timescales.[48]

[48] Ongoing efforts in the United States and Europe are moving toward standardization of HVDC transmission design and related interoperability (among others). Examples of these include DOE (2023) in the United States and InterOPERA (InterOPERA 2023) in Europe.

Differences between MT-HVDC nodal scenario and zonal scenario

As noted in the methodology sections of this chapter, ReEDS results do not provide prescriptive zone-to-zone discrete HVDC lines and converter pairs. When expanding the nodal transmission, the study team made decisions about transmission expansion using ReEDS results as a guideline, in addition to using the nodal industry planning cases network topology, semibounded power flows after disaggregation of generation and storage, and related information that might impact actual network expansion.

For the MT-HVDC scenario, there are many additional challenges beyond those in the Limited and AC scenario in deciding on expansion, including the need to embed HVDC into large and complex HVAC networks where there is limited existing HVDC transmission. Therefore, the study team approached this by using discrete HVDC expansions as a starting point and building out HVAC around this through an iterative process to enable increased use of existing networks. In some cases, express HVDC corridors skipped over ReEDS zones where power was evidently moving through zones instead of using that zone as a source or sink. In practice, these zones could potentially tie into the HVDC line that is passing through via additional converter capacity. In the end, if enough transmission was added to meet the requirements of a reliable system for 2035—balancing supply and demand and enabling generation to move to load centers and meet demand as planned by the ReEDS scenarios—the transmission expansion was considered complete.

The result of this approach is the MT-HVDC nodal scenario exhibits much less new HVDC transmission capacity than seen in the zonal ReEDS scenarios. One of the primary reasons for this is the nodal production cost modeling scenarios are not directly assessing resource adequacy with multiyear weather data (they are run for only one weather year). So, where ReEDS may have seen a substantial amount of resource adequacy benefit over the full 7-year perspective (see Chapter 2), discrete nodal production-cost and power flow models might not capture these trends and potential additional value of transmission. Future work could benefit from verifying network expansions on many future model years with varied weather and further extending the Z2N workflows to additional modeling domains where this value can be captured.

An additional consideration in building out the MT-HVDC scenario is HVDC is applied as a transmission network expansion solution only in cases where it is a clear and obvious solution for long-distance, high-capacity power transfer needs as guided by the ReEDS findings. Therefore, the study team relied on it only when it was clearly the best solution relative to more incremental AC transmission expansion.

For context on the scale of expansion achieved in the MT-HVDC scenario, global HVDC installed capacity by the end of 2023 was ~300 GW (the 10-year pipeline is an additional ~150 GW) (Johannes P. Pfeifenberger et al. 2023). With the full implementation of the nodal MT-HVDC scenario for CONUS alone, the global HVDC market would increase by 50% by 2035.

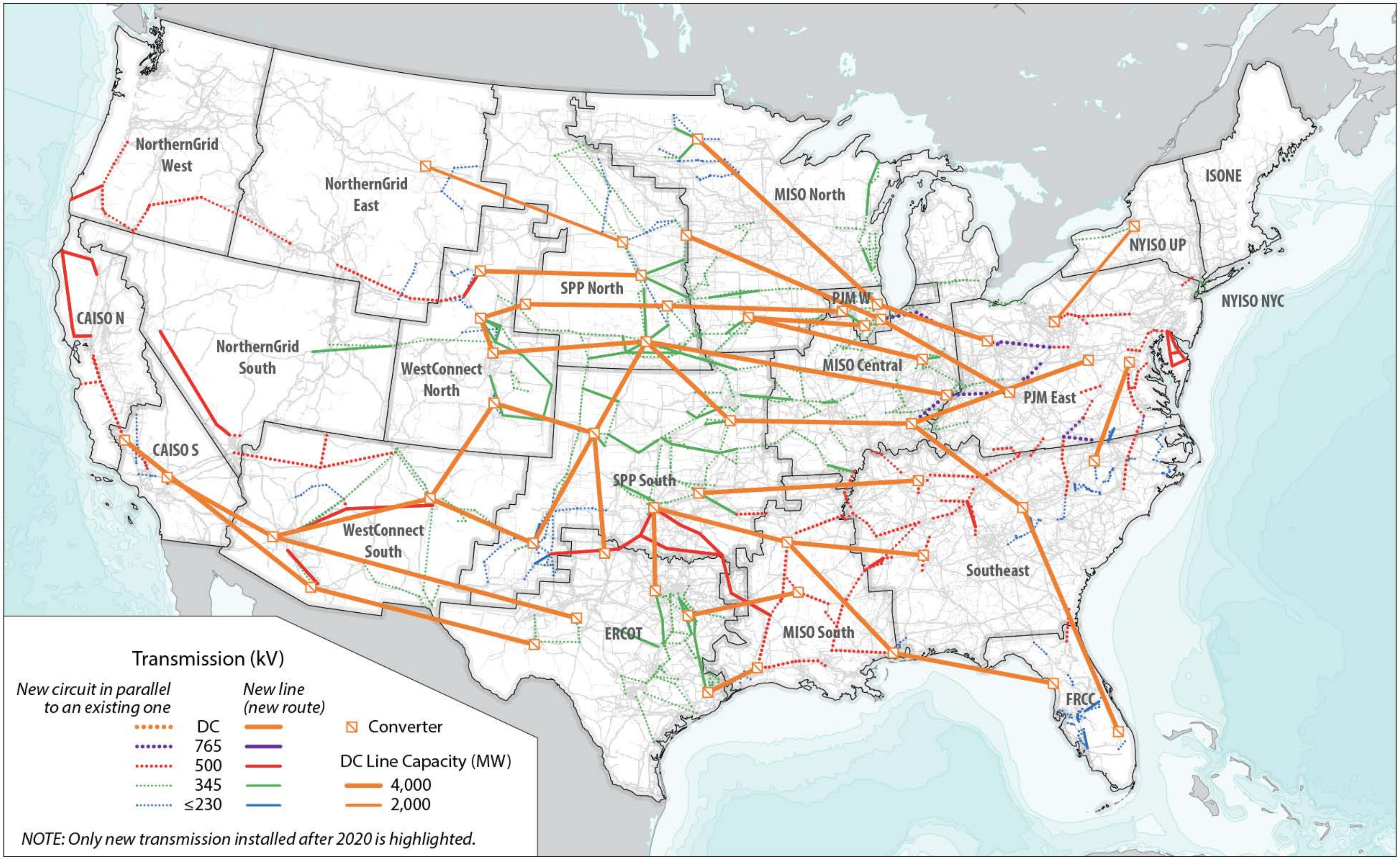


Figure 18. Transmission portfolio solution for MT-HVDC scenario for the model year 2035

3.3 Operations of Highly Decarbonized Power Systems

The following presents results of the annual production cost modeling for the final contiguous U.S. nodal scenarios for the model year 2035.

3.3.1 Interregional transmission is highly used to move renewable power to load centers but also to balance resources across regions

Transmission expansion in the AC and MT-HVDC scenarios enables large amounts of power to flow across major interregional interfaces. As seen in the flow duration curves in Figure 19, the scale of power flows between the Southeast and MISO (Central) regions increases in the AC scenario—up to 10.1 GW and ~27 TWh of annual energy—compared to the Limited scenario where only up to 2.6 GW of flow and ~10 TWh of annual energy is exchanged across the interface. Though the dominant contributor to the differences is the magnitude of the interregional transfer capacity, some of this difference is also attributable to the 3%–8% of congested hours where more congestion exists in the Limited scenario relative to the AC scenario (shown by the flat portion of the curves). Further, the predominant flow of power from MISO (Central) to Southeast (70%–75% of the time) indicates low-cost predominantly wind resources in the MISO region (in all scenarios) are consumed in the Southeast for parts of the year. MISO is also a net exporter to PJM, sending a net of 105 TWh annually.

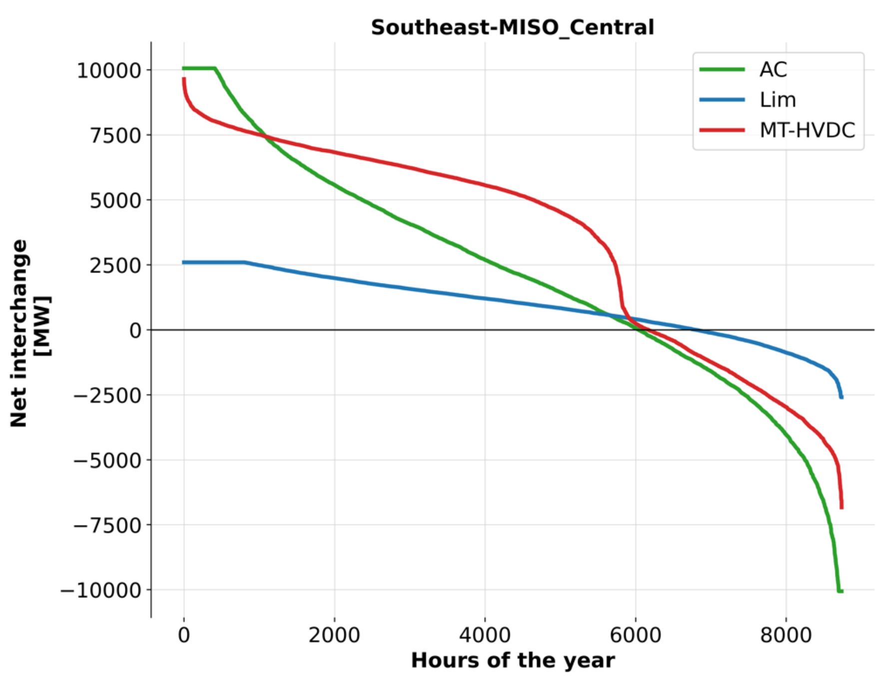


Figure 19. Flow duration curve between MISO-Central and the Southeast

Positive values indicate power is flowing from MISO-Central to the Southeast; negative values indicate flow from Southeast to MISO-Central.

In other areas, such as the ties between the Southeast and FRCC, the interregional transmission infrastructure experiences increased average utilization compared to other interfaces. The lines that comprise the interface between SERTP and FRCC regions play an important role in leveraging diurnal complementarities between solar PV systems and BESS (in FRCC) and combined wind, solar PV, and other dispatchable technologies (in the Southeast). This balancing of resources between regions is demonstrated through the FRCC and Southeast flow duration curves and diurnal flow distributions shown in Figure 20. Although there are larger maximum amounts of power flows between these two regions in the AC relative to Limited scenario, and further larger transfers for the MT-HVDC scenario, there is a difference in the relative distribution of these flows as well as directionality. Figure 22 (b–d) illustrates these differences, showing how large amounts of wind are imported into FRCC during the early mornings and late evenings and solar is exported into the Southeast in the afternoon, using the full capacity of the interface in both directions. This is driven by the increased amount of solar PV in FRCC in the AC scenario. The diurnal flow in the Limited scenario is characterized by a wider distribution of imports and exports but is punctuated by more exports (or relatively lower imports) from FRCC to the Southeast in the morning hours (06h00–10h00) and later evening hours (19h00–21h00), which is particularly pronounced during the spring and summer months (March–August). The annual average dispatch stacks in 2035 are shown in Figure 21 for FRCC and the Southeast (for AC and MT-HVDC scenarios), demonstrating shared resources between these two regions.

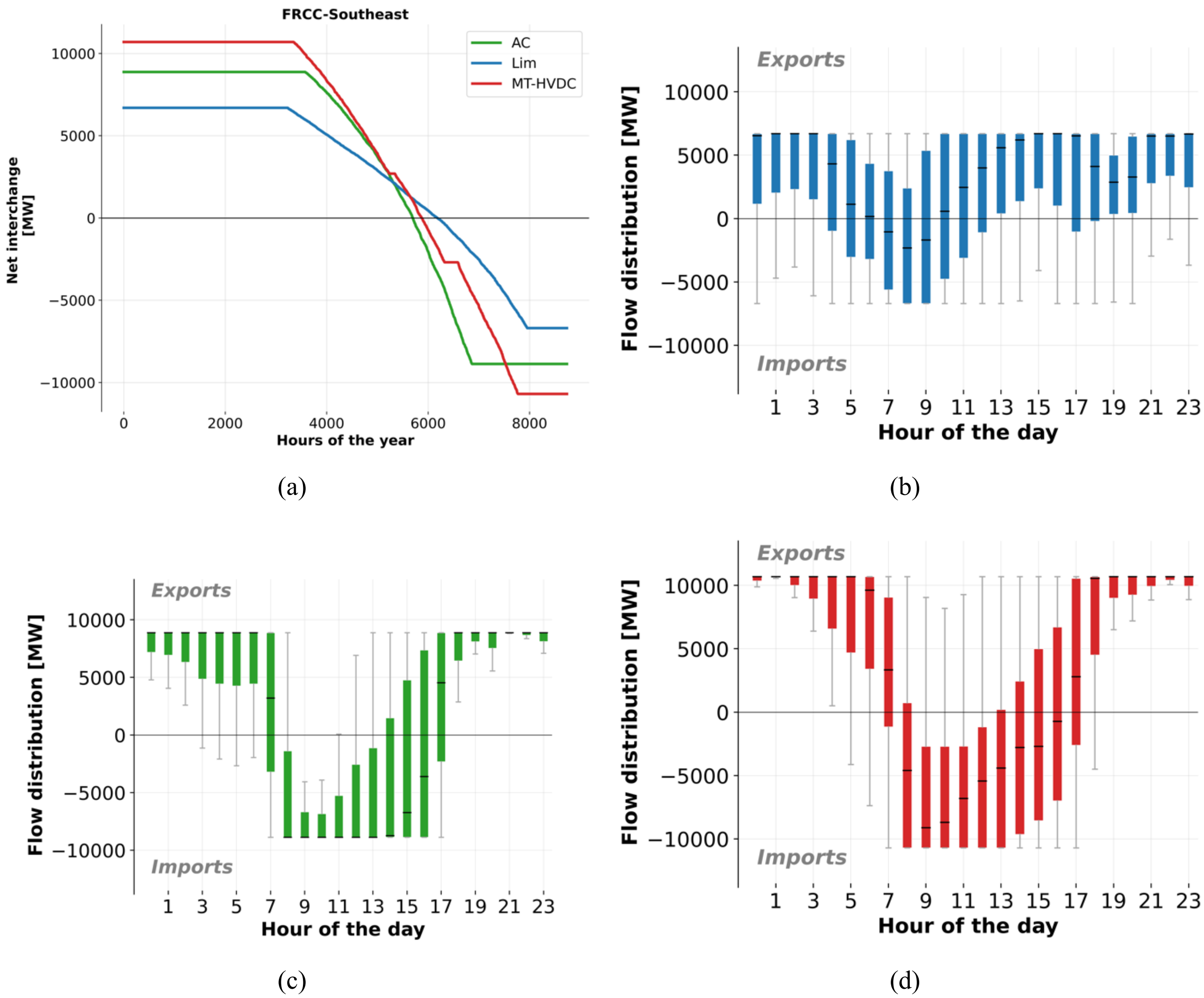
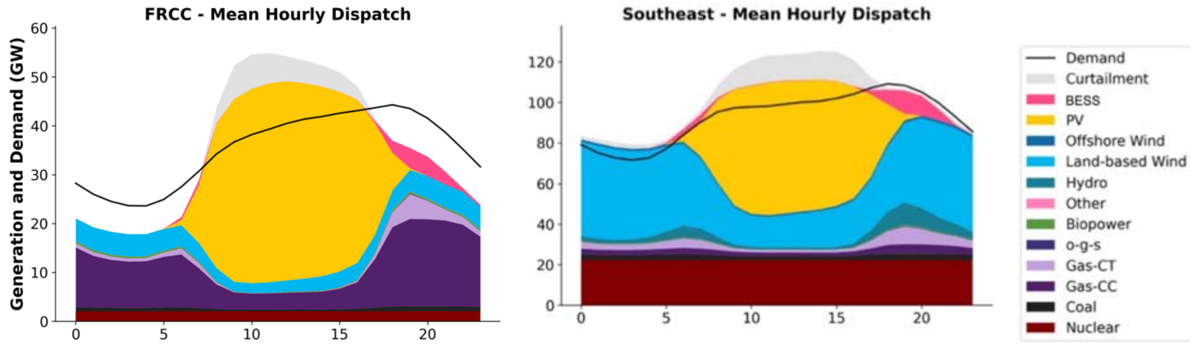
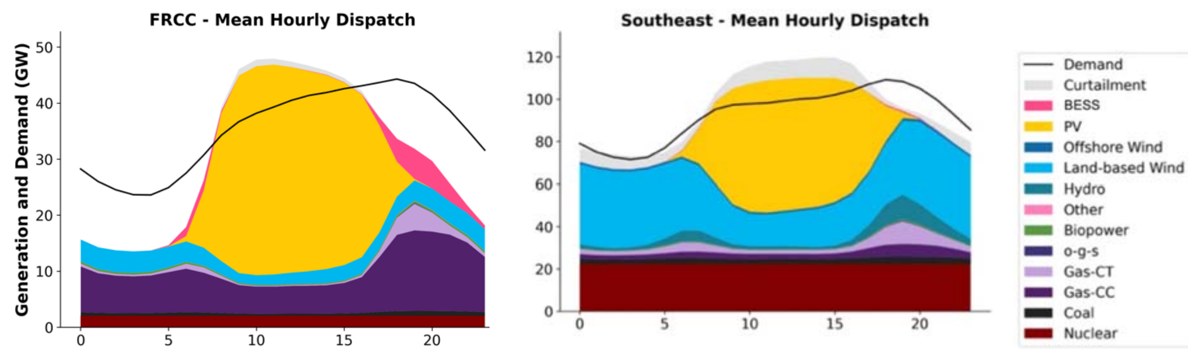


Figure 20. Flow duration curves (a) and distribution of flows (b), (c), (d) between FRCC and the Southeast



(a) AC scenario



(b) MT-HVDC scenario

Figure 21. Dispatch stack for peak demand period in FRCC and Southeast for (a) AC and (b) MT-HVDC

3.3.2 Diurnal and seasonal variability may require increased flexibility as well as interregional coordination to minimize curtailment

The Limited scenario exhibits the least amount of curtailment of VRE resources relative to the AC and MT-HVDC scenarios, driven by the combination of more installed wind and solar capacity in the AC and MT-HVDC scenarios (with the same demand) and less interregional transmission. As an example of this, for 15%–22% of the year, there is more energy available from VRE sources than there is demand in the Eastern Interconnection (greater than 1.0 in Figure 22). Consequently, even with no network congestion, oversupply would result in VRE curtailment because there is not enough storage capacity to consume the extra power in all periods (a trade-off established in the zonal ReEDS scenarios between storage investment and operational costs relative to curtailed energy).

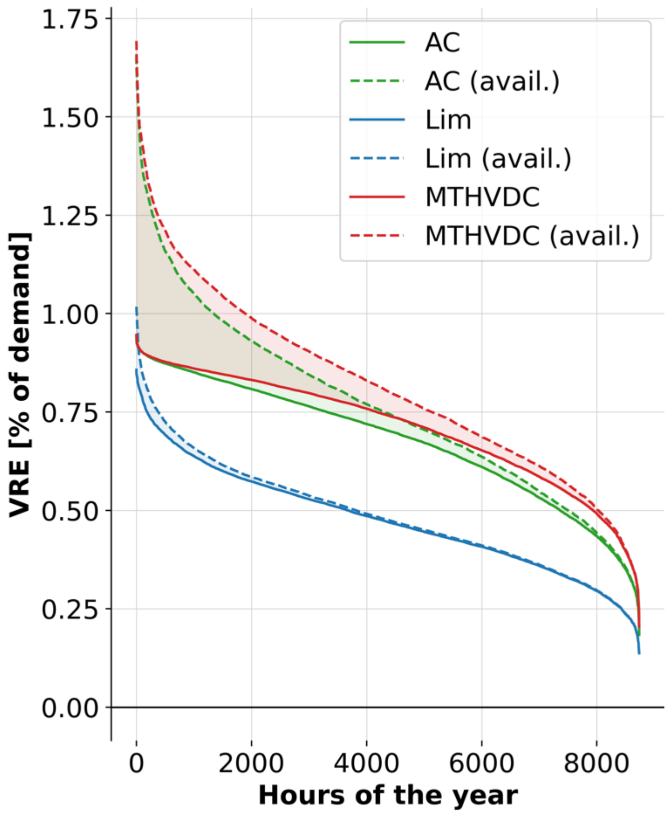


Figure 22. VRE production duration curve (normalized to demand) for the Eastern Interconnection

Figure 23 shows the monthly generation per interconnection for the AC scenario; Figure 24 demonstrates this for CONUS for the MT-HVDC scenario (monthly curtailment can be seen in the light-gray shade). The Limited scenario exhibits monthly curtailment patterns similar to those of the AC scenario but with lower absolute levels (as also indicated in Figure 22). With the large amounts of VRE resources added in scenarios with interregional transmission expansion, curtailment becomes common throughout the year and is particularly higher in regions with disproportionately larger amounts of VRE resources added relative to demand (SPP and MISO in particular). Similarly, the seasonal pattern of curtailment is driven by relatively high wind energy resources in the spring and fall, coinciding with relatively lower demand months (at an interconnection level and CONUS level) combined with lower correlation with the availability of hydro resources throughout other parts of the year.

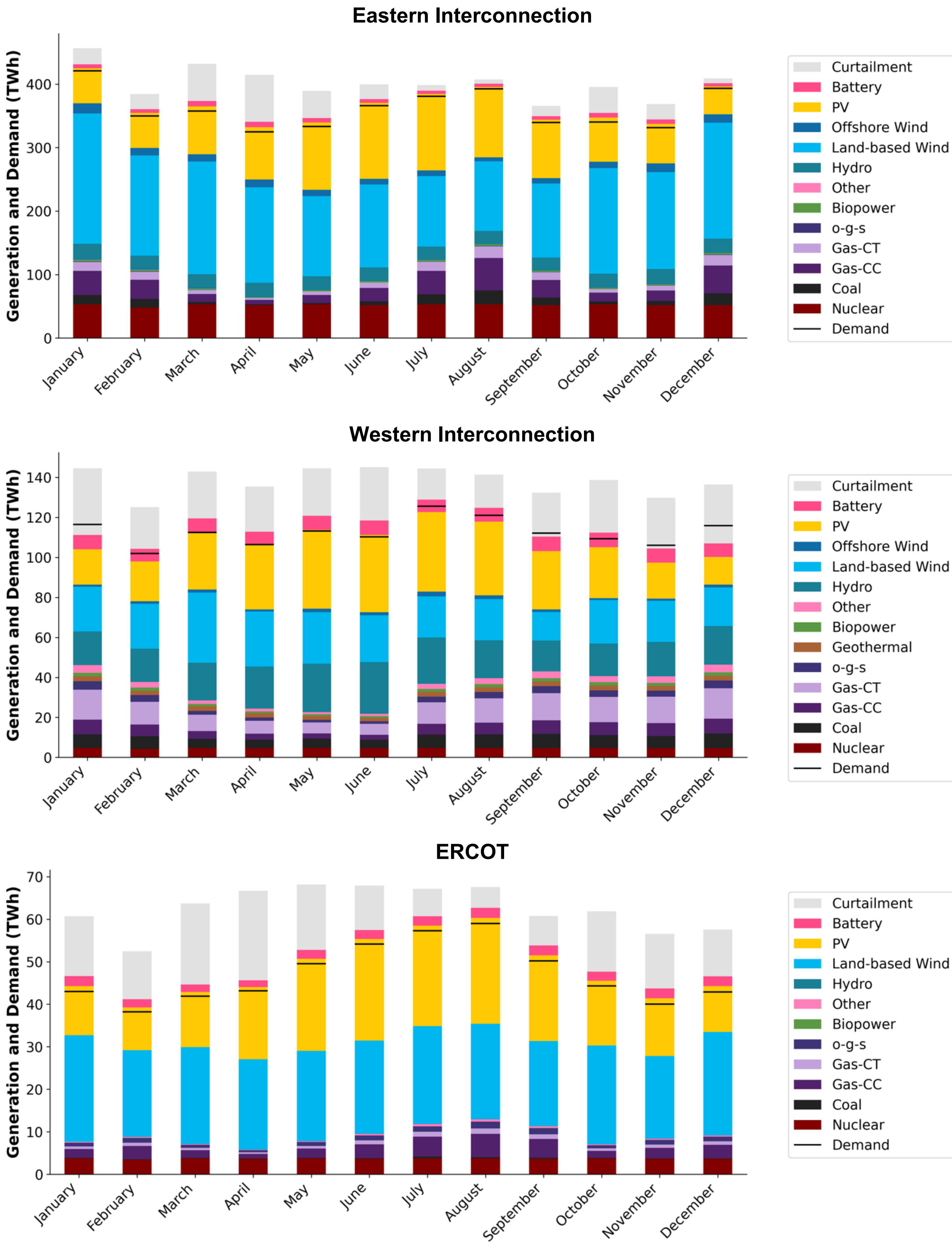
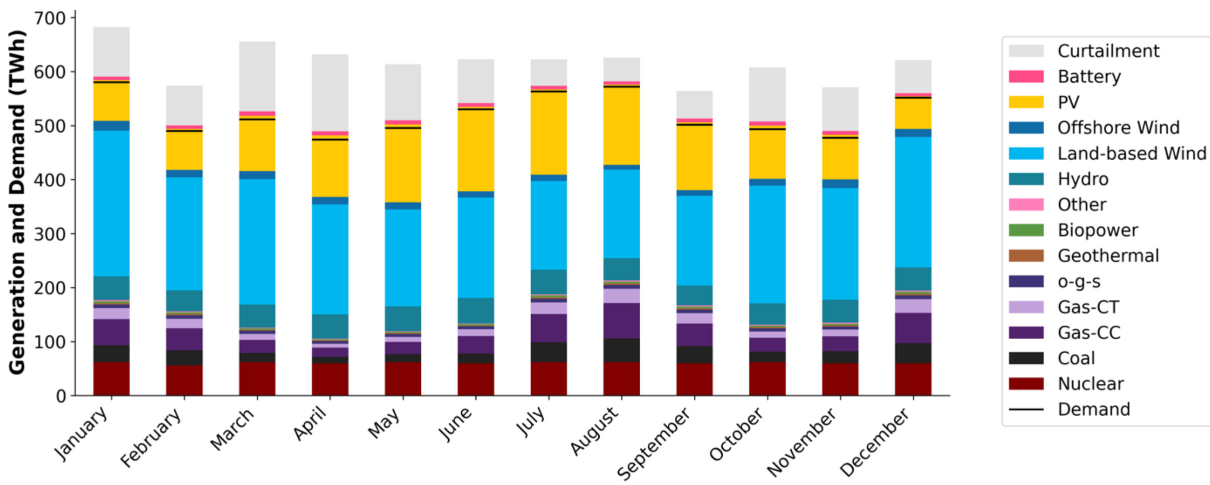
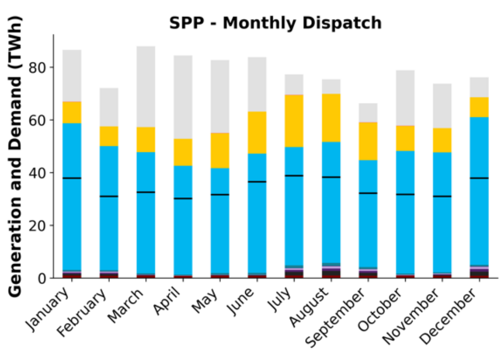


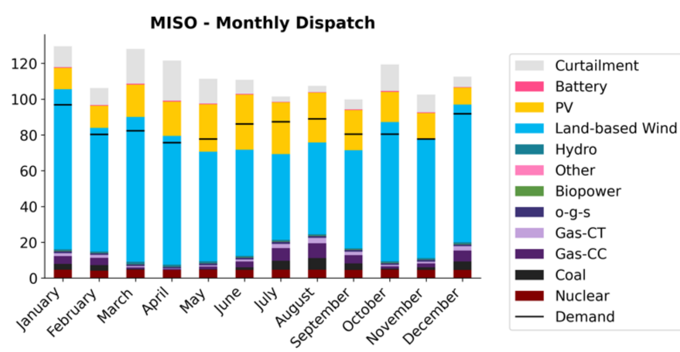
Figure 23. Monthly generation (per interconnection) for the AC scenario

These demonstrate monthly curtailment patterns (higher curtailment in late winter and early spring); similar trends exist for the Limited and MT-HVDC scenarios.



(a)





(b) (c)

Figure 24. Monthly generation (CONUS) for (a) MT-HVDC scenario and (b) within SPP and (c) MISO

Demonstration of monthly curtailment patterns CONUS-wide as well as specific regions with large amounts of installed land-based wind capacity where general trends are highlighted further.

Dispatch trends demonstrating flexibility needs across the nodal scenarios are demonstrated via dispatch stacks for various seasonal periods for the Limited, AC, and MT-HVDC scenarios in Figure 25, Figure 26, and Figure 27, respectively. As expected, higher levels of curtailment exist in the daytime hours when wind and solar PV are both producing simultaneously and in scenarios where more VRE make up the resource mix (AC and MT-HVDC). This curtailment supports balancing compared to the Limited scenario because of the significantly more wind and solar installed for the same demand even though there is more interregional transmission expansion. The use of short-duration storage resources (in the form of BESS) also plays a large role in balancing, where discharging of storage occurs in some morning hours as demand increases but is mostly concentrated in evening hours after being charged during the day when there is excess wind and solar. This finding is robust across interconnections and scenarios.

The curtailment of VRE is driven primarily by the trade-offs between resources and transmission in ReEDS. Once translated into nodal production-cost models with improved temporal and transmission networks representation, curtailment emanates further from the combined flexibility characteristics[49] of the complementary fleet of dispatchable technologies and interregional transmission expansion. The fast-ramping nature and low absolute levels of residual demand after wind and solar generators are dispatched are particularly noticeable for BESS, combined cycle gas, and combustion engines where increased unit starts/stops, increased periods of operation at minimum-stable levels, and increased unit ramping are required.

[49] Flexibility is required for increased ramp rates, lower minimum operating levels, and more startups and shutdowns of supply resources to meet residual demand needs (within and across regions).

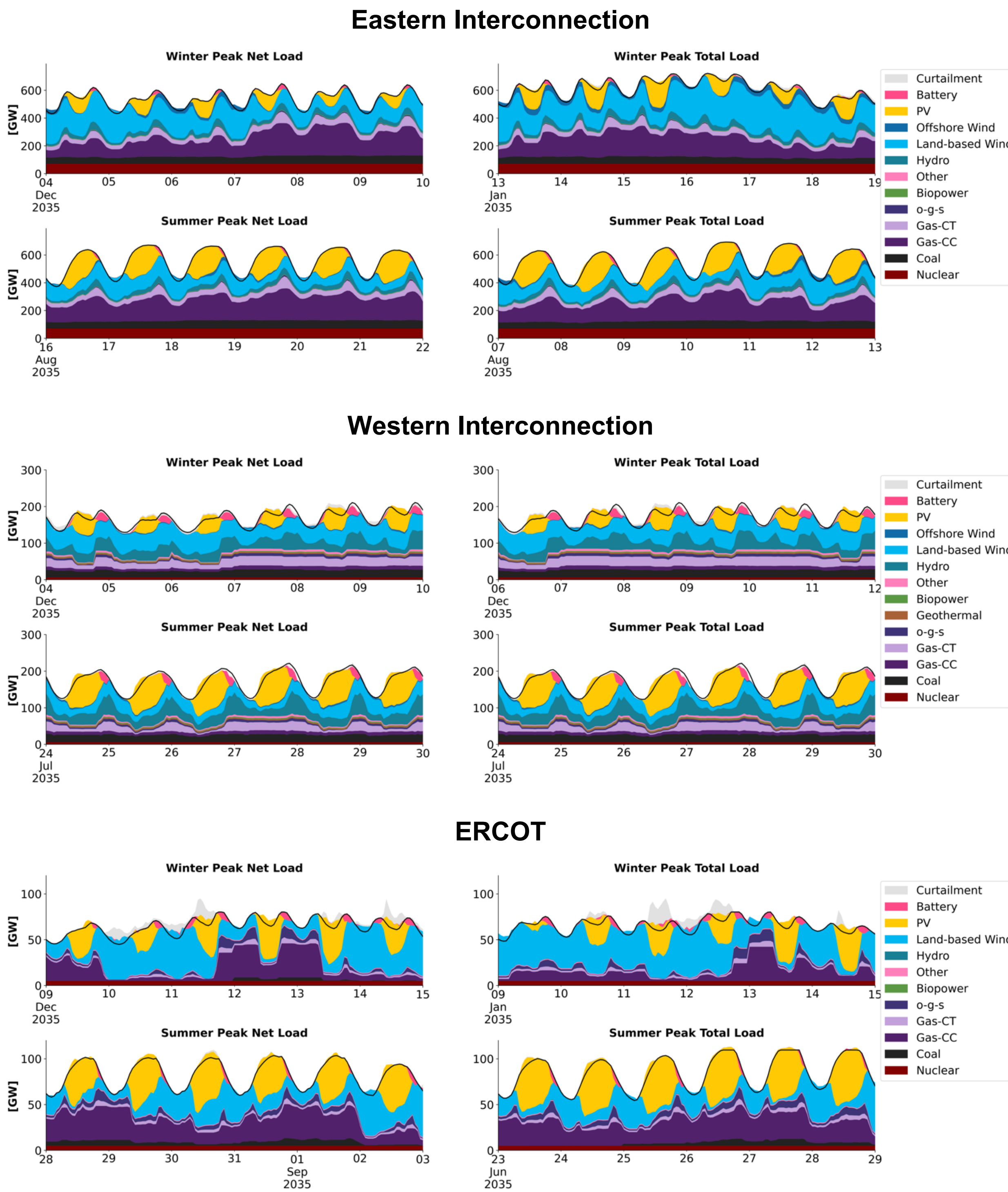


Figure 25. Seasonal dispatch stacks (per interconnect) for the Limited scenario

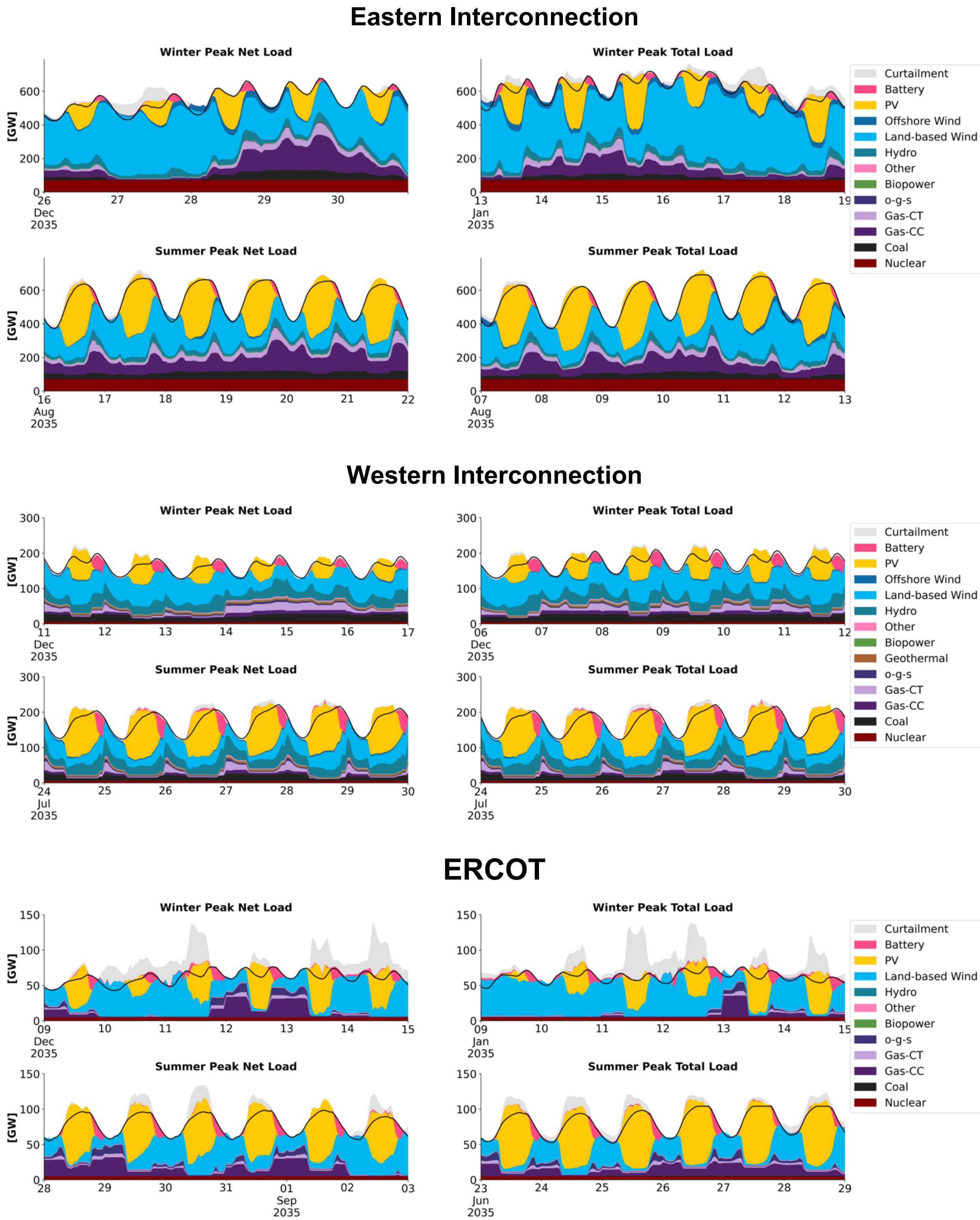


Figure 26. Seasonal dispatch stacks (per interconnect) for the AC scenario

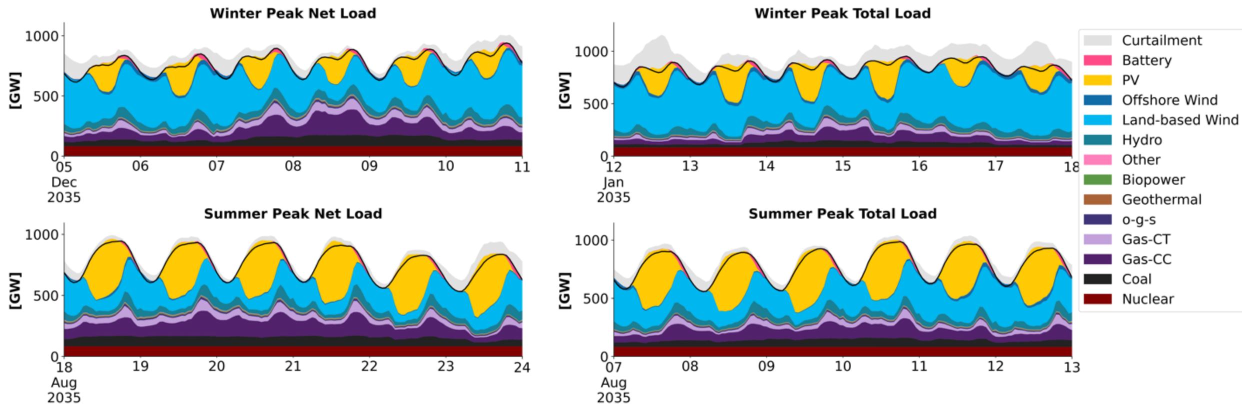
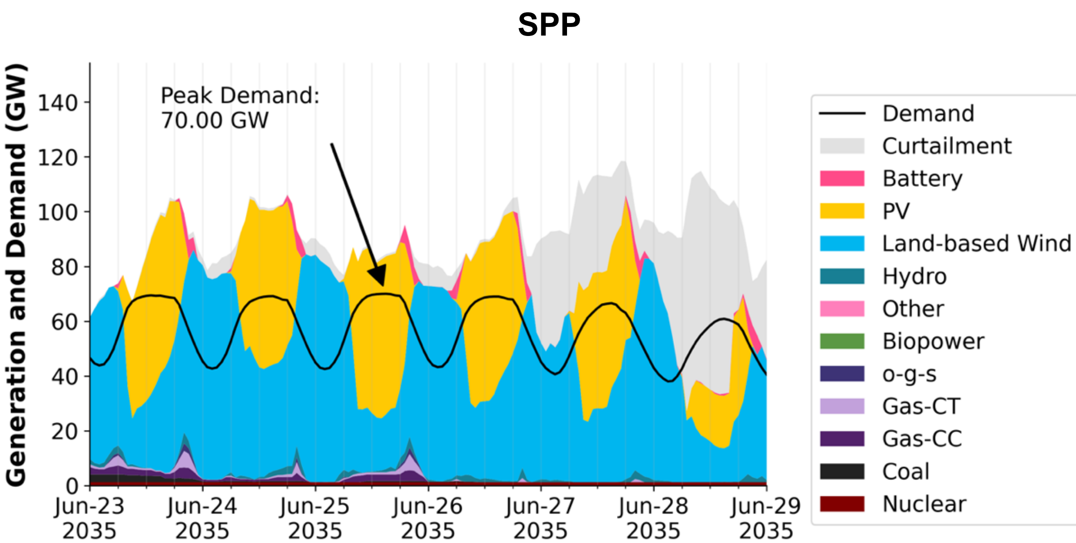


Figure 27. Seasonal dispatch stacks (continental United States) for the MT-HVDC scenario

3.3.3 Regions with high amounts of VRE relative to demand become major exporters and often exhibit very low amounts of synchronous generation

The AC and MT-HVDC scenarios represent futures with large amounts of energy transfers between regions as transmission expansion better connects them. This could drastically change the role of certain regions or increasingly solidify their role as large power exporters. For example, as demonstrated for the AC scenario in Figure 28 for a peak demand week in SPP and MISO, large amounts of VRE resources relative to demand exist. This results in large exports of wind and solar (where supply is greater than demand in Figure 28).[50] These exports to other regions result in operating periods with very few online synchronous generating units in the region and large numbers of inverter-based resources (IBRs) in the form of wind and solar generators in operation. These operating periods are important to scope and dimension the scale of mitigation measures and solutions to address stability concerns with such high levels of IBRs and low levels of synchronous generation. However, these mitigation measures and solutions are out of scope for the NTP Study.

[50] Similar patterns with respect to exports of wind and solar also exist in the MT-HVDC scenario.



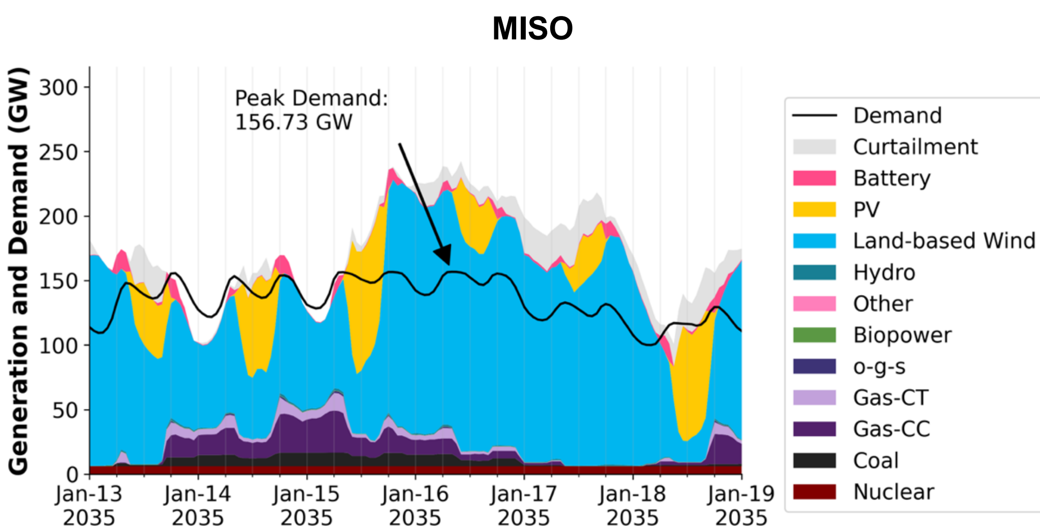


Figure 28. Dispatch stacks of peak demand for SPP (top) and MISO (bottom) for the AC scenario

Figure 29 shows the net interchange relative to native demand for the regions across the continental United States, where a positive indicates exports and a negative indicates imports. Several regions move power in one predominant direction as exports (SPP, MISO, WestConnect, ERCOT) and as imports (CAISO, PJM, NYISO) whereas others move power bidirectionally (NorthernGrid, SERTP, FRCC, ISONE). In the scenarios with more interregional transmission (AC and MT-HVDC), the relative amount of demand met by imports or the amount of power exported from a region increases, highlighting coordination between regions would be expected to increase. Across almost all regions, the AC and MT-HVDC scenarios lead to more overall energy exchange. More specifically,19% of the total energy consumed in the Limited scenario flows over interregional transmission lines whereas that number increases to 28% in the AC and 30% in the MT-HVDC scenario.

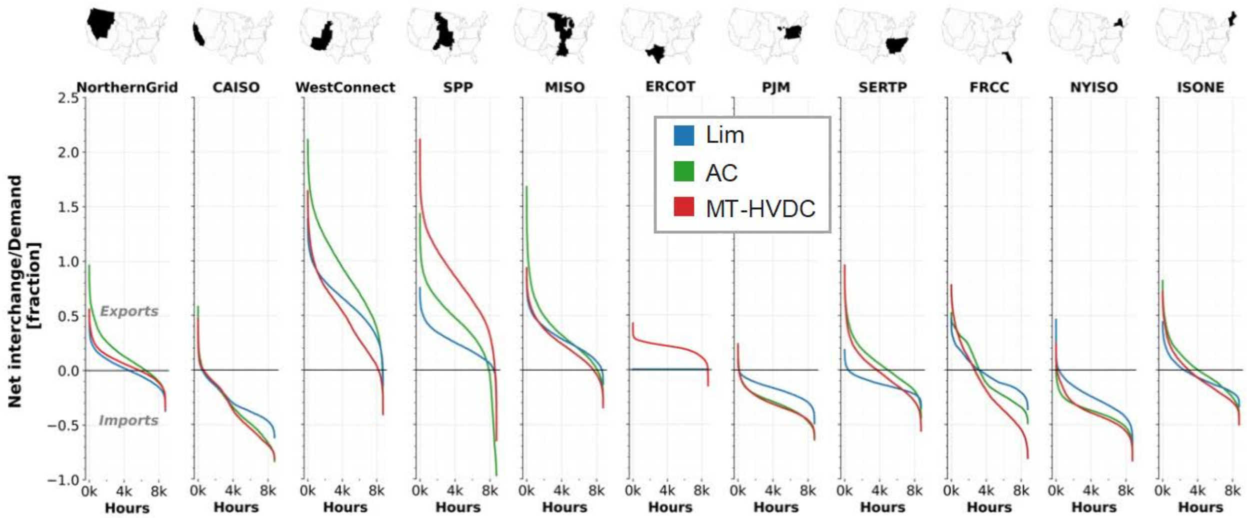


Figure 29. Ratio of Net interchange to for the 11 regions all hours of the year (2035) for Limited, AC, and MT-HVDC nodal scenarios

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.

4 Western Interconnection Results for Downstream Modeling

This section presents results derived from the earlier ReEDS scenarios; results were informed by the baseline analysis performed on the Western Interconnection.[51] The three earlier scenarios that are translated to nodal scenarios are all 90% by 2035 emission constrained, high-demand, with the Limited, AC, and MT-HVDC transmission frameworks.[52] The resulting nodal transmission expansions and production cost modeling results for the model year 2035 for the Western Interconnection are presented in this section.

The results are structured into three categories. Infrastructure changes, the results of the disaggregation, and transmission expansion are described in Section 4.1. Operational results from production cost modeling simulations of the 2035 model year follow in Section 4.2. Finally, the impact of infrastructure and operation changes are combined in an economic evaluation and analysis of the nodal scenarios in Section 4.3. In addition, this section uses regions familiar to stakeholders in the Western Interconnection. See Appendix B.2, Figure B-44 for a map of these regions.[53]

4.1 Translating Zonal Scenarios to Nodal Network Scenarios

This section describes the results of the resource disaggregation in the nodal models and the transmission expansion decisions made to accommodate the new resources. Details on the MT-HVDC design are provided in Appendix A.10.

4.1.1 Increased transmission expansion in the West via long-distance high-capacity lines could enable lower overall generation capacity investment by connecting the resources far from load centers

Though solar PV makes up the largest share of generation capacity in all three scenarios, the increased share of wind in the AC and MT-HVDC scenarios—enabled by more interregional transmission capacity—makes it possible to support the same load in the Western Interconnection with a lower level of total installed capacity.[54] Figure 30 shows the total Western Interconnection generation and storage capacity, and Figure 31 shows the resulting transmission expansion for the three scenarios.

The Limited scenario is characterized by significant amounts of solar and storage additions, particularly in the southwest and California. These drive a substantial amount

[51] For the baseline analysis, see Konstantinos Oikonomou et al. (2024). For details on the different assumptions used in ReEDS to create earlier and final scenarios, see Chapter 1 of this report.
[52] The MT-HVDC scenario is modeled with the Western Interconnection and the Eastern Interconnection; however, only results from the Western Interconnection footprint are included in this section. Appendix B.5 includes a map of the Eastern and Western Interconnection portfolios.
[53] Regions referenced in Section 4 are Northwest U.S. West and East (NWUS-W, NWUS-E), Basin (BASN), California North and South (CALN, CALS), Desert Southwest (DSW), and Rocky Mountain (ROCK).
[54] The economic analysis, Section 4.4, evaluates the trade-off between generation and transmission capacity.

of intraregional transmission along the southern border as well as around the Los Angeles (LA) Basin to collect the resources and connect them to load centers.

The AC scenario, capitalizing on the ability to build longer-distance interregional AC transmission, incorporates more high-quality wind resources from regions on the eastern part of the Western Interconnection (ROCK, BASN, DSW) compared to the Limited scenario. The transmission expansion helps connect the new wind resources to load centers in Colorado, Arizona, and the coast. The transmission expansion connects the remote wind areas to the 500-kV backbone but also reinforces the system and expands interregional connections to allow access to these load centers. In contrast, there is significantly less solar PV and storage capacity, particularly in the southwest in the AC scenario compared to the Limited scenario. Accordingly, there is less intraregional transmission, most notably along the southern border.

The MT-HVDC scenario is substantially different from the Limited and AC scenarios because four HVDC converters with 20 GW of capacity between the western and eastern interconnections are added. This enables a large amount of energy exchange across the seams, with imports from the SPP region being predominantly wind. The wind capacity in the MT-HVDC scenario is distributed similarly to the AC scenario at higher-quality locations along the east, supported by an HVDC backbone along the eastern part of the interconnection with further connections toward the coastal load centers. The total wind capacity, however, is only 9 GW more than the Limited scenario given the ability to import additional high-quality resources across the seams.[55] Like the AC scenario, the MT-HVDC scenario has less solar and storage installed than the Limited scenario and therefore less intraregional transmission expansion along the southern border.

Transmission expansion decisions are categorized into three groups that are outlined further in the following paragraphs.

The first is high-voltage transmission lines that can span large, potentially interregional, distances but whose primary role is to collect VRE injections from remote locations and give them a path to the larger bulk system. For example, this type of expansion characterizes much of the built transmission in Montana or New Mexico in all scenarios.

A second type of expansion reinforces congested corridors in the existing bulk system or expands the bulk system via new corridors. The difference between this category and the first is the lines in this category are primarily intended to connect regions. Though not a requirement, flow on these lines is more likely bidirectional. The 500-kV expansion across northern Arizona is one such example, as well as the Garrison to Midpoint lines in the Limited and AC scenarios. Perhaps most prominently, all the HVDC expansion in the MT-HVDC scenario is in this category.

[55] In fact, the difference between the installed wind capacity in the AC and MT-HVDC scenarios is very close to the roughly 20 GW of HVDC capacity across the seams.

Finally, a third type of expansion focuses on intraregional reinforcement and access to load. The expansion around the LA or Denver load pockets are examples in all the scenarios.

Appendix B.5 provides region-specific descriptions of the rationale for the expansion decisions.

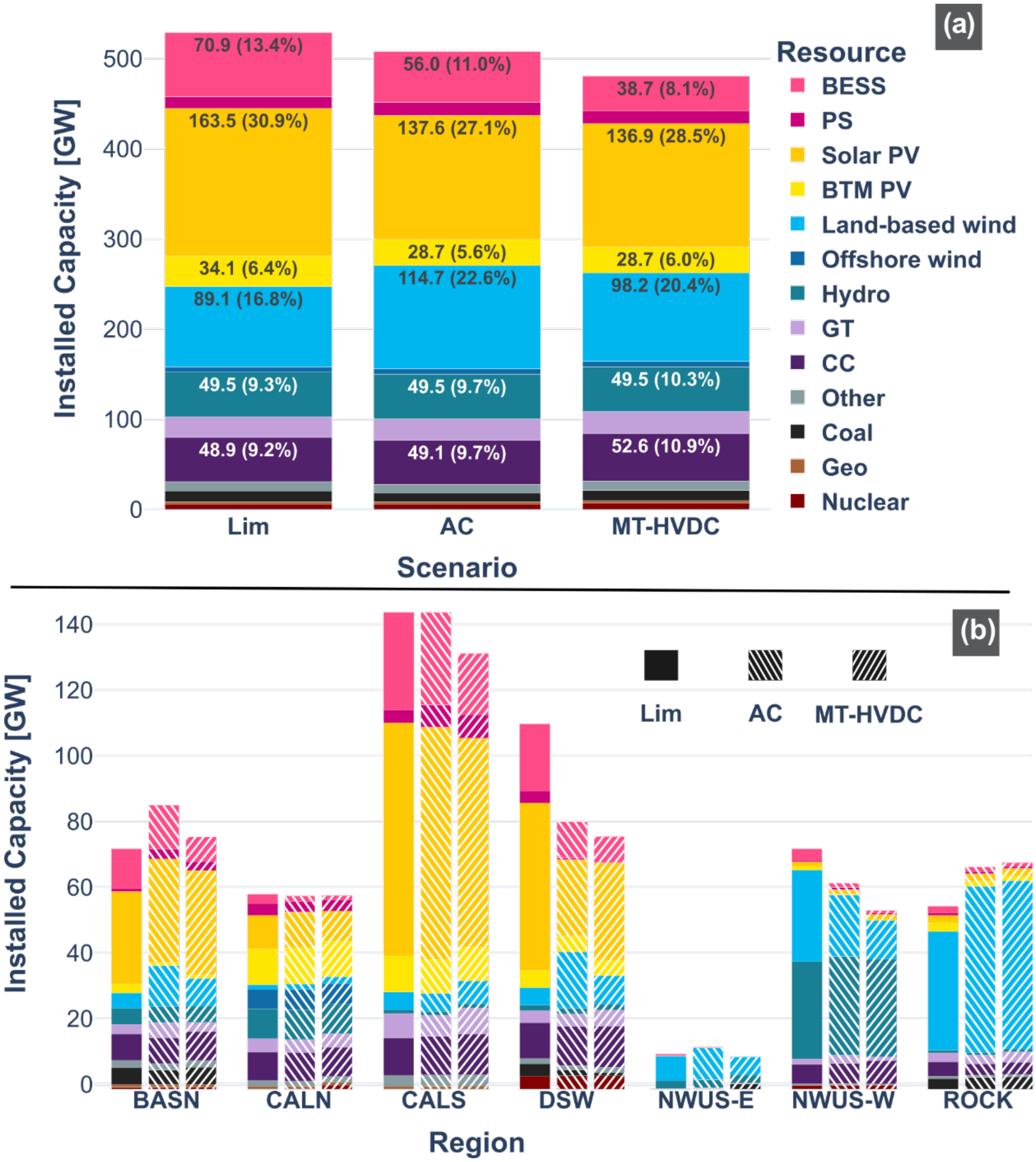


Figure 30. Net installed capacity after disaggregation: (a) Western Interconnection-wide; (b) by subregion

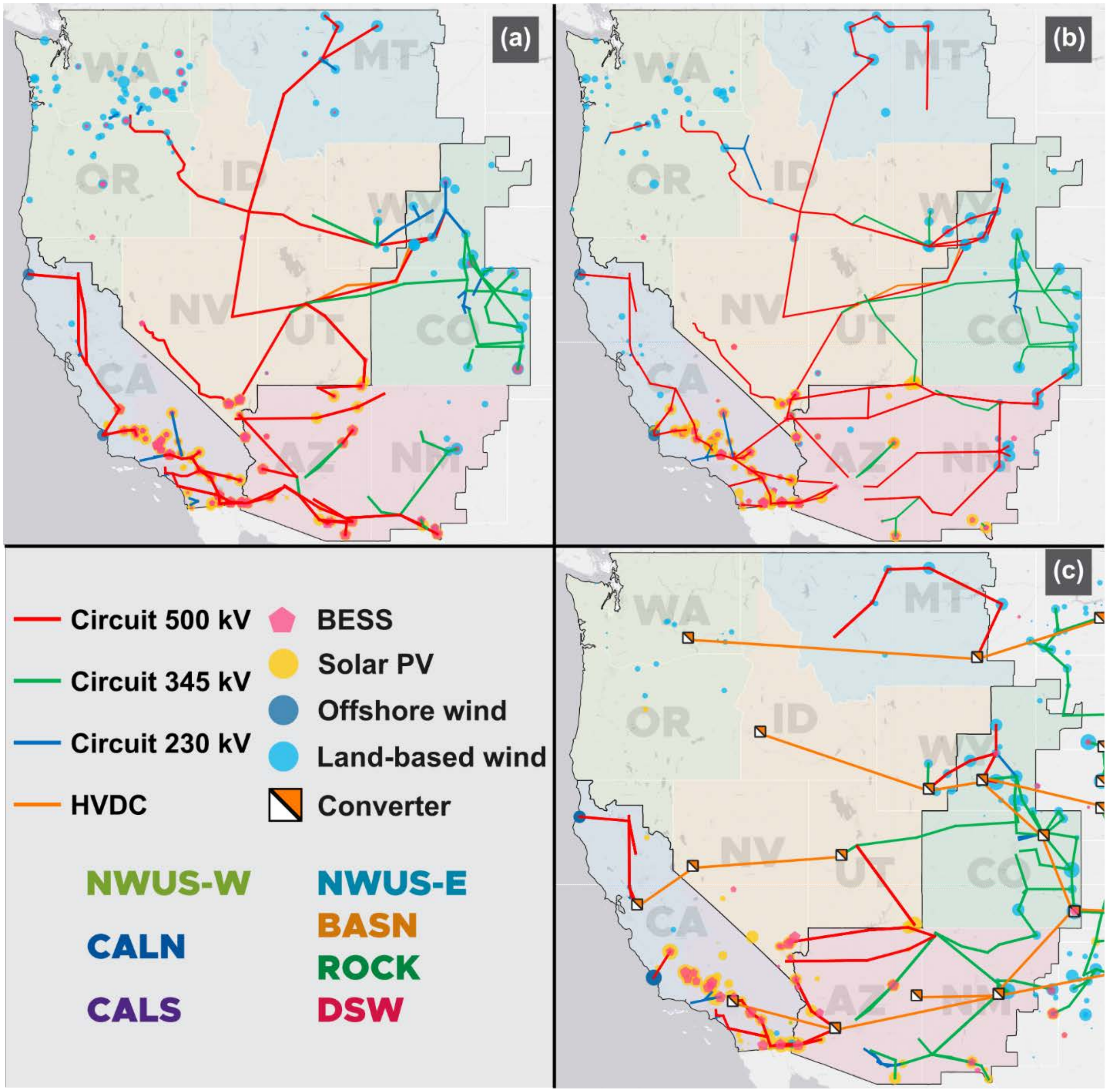


Figure 31. Transmission expansion results on the Western Interconnection footprint

Nodal transmission expansion is shown for the earlier rounds ReEDS scenarios with (a) Limited, (b) AC, and (c) MT-HVDC results shown. Expansion results for the full MT-HVDC scenario are provided in Appendix B.5 (for CONUS).

4.2 Operations of Highly Decarbonized Power Systems

This section presents operational results from production cost simulations on the three translated scenarios. These results serve two distinct purposes:

- Validation: Demonstrate an operationally viable realization of the capacity expansion results that can be used to seed further downstream models (see Chapter 4 for power flow and Chapter 5 for stress analysis).
- Present analysis of operation under ~90% renewable penetration and the role of transmission and generation technologies in the operation of such futures.

Appendices A.8 and A.9 provide more detail on the simulation process and the earlier ReEDS scenario translations.

4.2.1 Operational flexibility is achieved by a changing generation mix that correlates with the amount of interregional transmission capacity

For the Western Interconnection scenarios, as interregional transmission increases, the share of wind in the total energy mix increases from 270 TWh (21%) in the Limited scenario to 346 TWh (28%) in the AC scenario and 439 TWh (36%) in the MT-HVDC scenario. The reliance on gas generation (gas turbine [GT] and combined cycle [CC]) makes up a smaller share as interregional transmission increases from 11% in the Limited to 10% in the AC and 5% in the MT-HVDC scenario. Figure 32 shows the annual generation in the entire Western Interconnection and by region. Interregional imports and exports have a large impact on certain regions in the AC and MT-HVDC scenarios. In particular, the HVDC connections (shown as DC imports in Figure 32) to the Eastern Interconnection in the MT-HVDC scenario have a large impact on flows around the entire interconnection.

Storage charge and discharge patterns highlight the different sources of flexibility between the scenarios. Figure 33 shows the average weekday dispatch in the third quarter of the year, which in the Western Interconnection contains the peak load period. Storage plays a significant role in meeting the evening ramp and peak, but it is more pronounced in the Limited and AC scenarios. In the MT-HVDC scenario, the lower storage contribution is compensated by more wind as well as imports through the HVDC links that show a similar pattern to storage. In the AC and MT-HVDC scenarios, storage discharge reduces significantly overnight (hours 0–5) compared to the higher levels in the Limited scenario. In the AC scenario, the nighttime generation is picked up by more wind whereas in the MT-HVDC scenario the HVDC imports—in addition to the higher wind generation—help drive down the share of gas generation dispatched overnight. Figure 34 shows the average weekday storage dispatch over the whole year, further emphasizing the wider charge and discharge range as well as overnight discharge level in the Limited scenario.

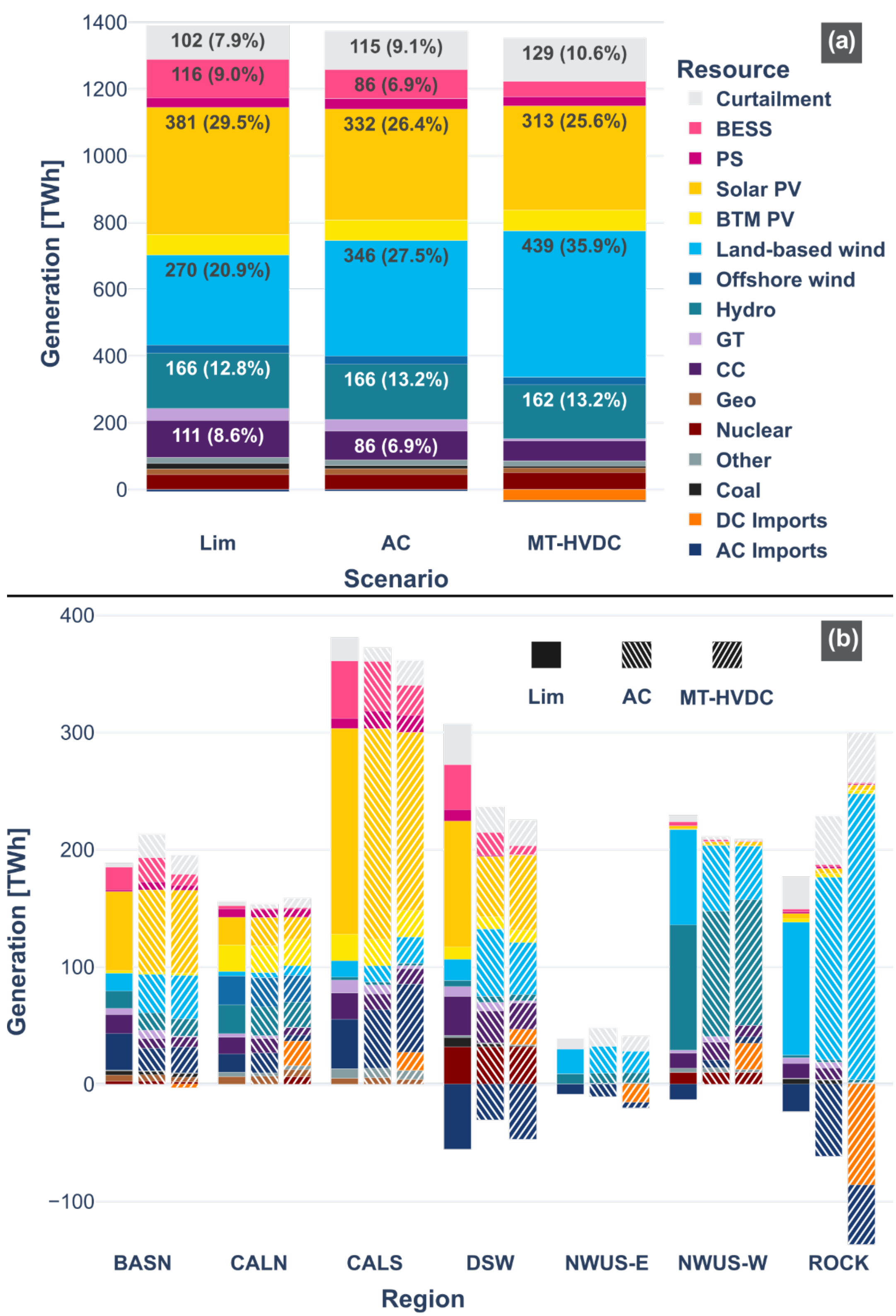


Figure 32. Annual generation mix comparison for (a) Western Interconnection and (b) by subregion

Percentages are with respect to total generation within the footprint, in other words, neglecting the DC and AC imports, and curtailment values. Storage values are for generation mode only.

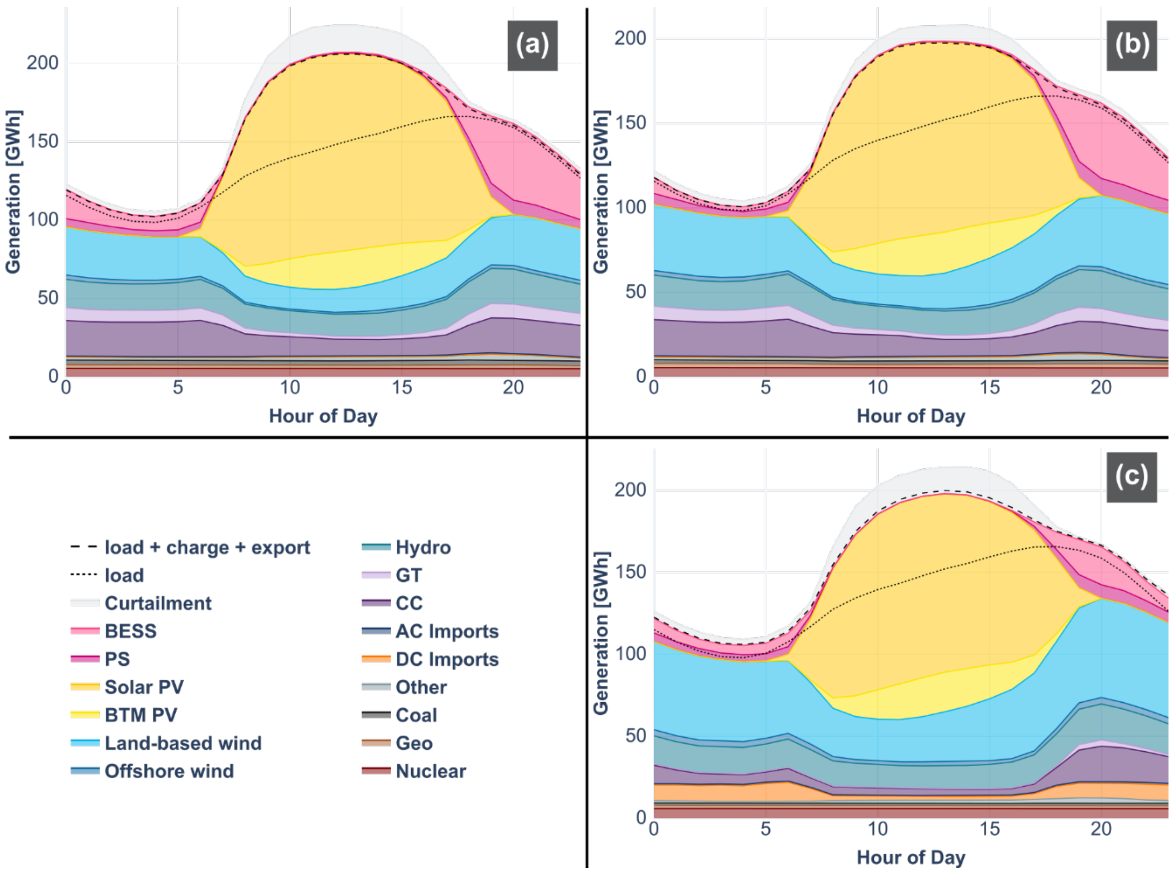


Figure 33. Average weekday in the third quarter of the model year for (a) Limited, (b) AC, and (c) MT-HVDC

DC imports refer to energy imported across the seam from the Eastern Interconnection. Storage values are for generation mode only.

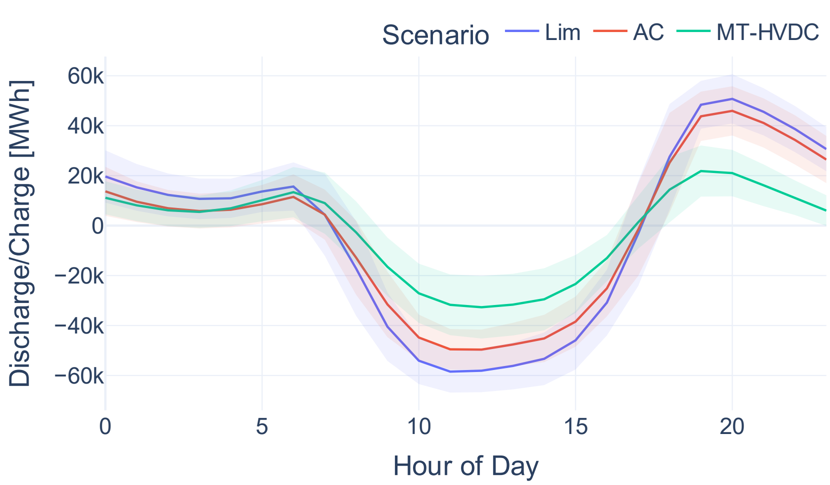


Figure 34. Average weekday storage dispatch for the Western Interconnection

Lines are the average value; shaded areas are ±1 standard deviation around the mean.

4.2.2 Transmission paths connecting diverse VRE resources will experience more bidirectional flow and diurnal patterns

Increased interregional transmission and its correlation with more geographically dispersed VRE resources lead to more pronounced diurnal patterns on transmission paths, largely driven by solar PV generation, as well as changes in the dominant directionality of flow.

The upgraded transmission paths for the additional wind resources in New Mexico, Colorado, and Wyoming toward the California load centers passes through southern Nevada and Arizona in the AC and MT-HVDC scenarios. Figure 35 shows the flows on the interfaces between CALS and BASN (southern Nevada) as well as DSW (Arizona).[56] During the nighttime hours, the magnitude of the import flows to California increases on average by around 5 GW in both the AC and MT-HVDC scenarios compared to the Limited scenario. During the daytime hours, the significant solar resources in CALS reduce the flow on the interfaces, resulting in a diurnal pattern that reflects the solar PV output.

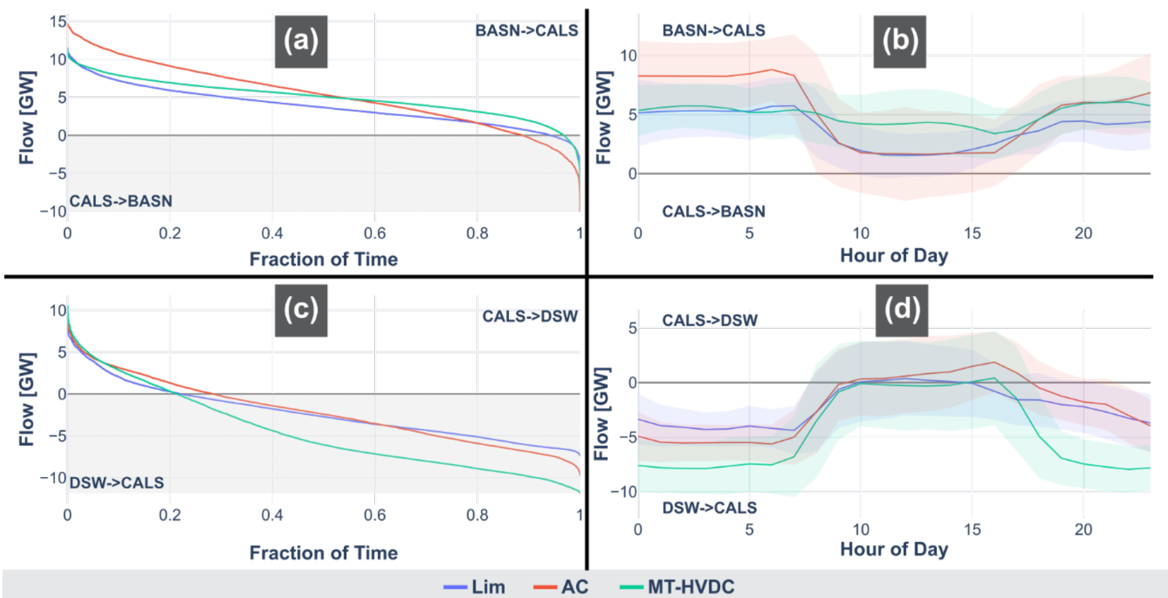


Figure 35. Flows between Basin and Southern California and between Desert Southwest and Southern California

Panels (a) and (c) are flow duration curves. Panels (b) and (d) show average weekday plots with ±1 standard deviation shaded.

The interface between the Basin region (BASN) and the Pacific Northwest (NWUS-W) in Figure 36 is an example of how interregional transmission impacts the dominant flow direction between regions. In this case, the transmission capacity between the two regions in the three scenarios is similar, but the impact of expansion elsewhere in the

[56] Note in the AC scenario a significant portion of the new 500-kV transmission passes through southern Nevada whereas in the MT-HVDC scenario, the HVDC corridor connects Arizona (DSW) to southern California.

Western Interconnection impacts how that transmission capacity is used. Central to the shift in usage pattern is the reduction of wind resources in NWUS-W (cf. Figure 30) in favor of eastern regions of the Western Interconnection, which is enabled by more interregional expansion. Figure 36 shows how NWUS-W shifts from exporting power to BASN for more than 50% of the year in the Limited scenario to importing power for 60% (MT-HVDC) and 75% (AC) of the year. This underscores the shift in total yearly energy exchange for NWUS-W, seen in Figure 32, from 13 TWh *exporting* to 7 TWh *importing* and 28 TWh *importing* in the Limited, AC, and MT-HVDC scenarios, respectively.

In the MT-HVDC scenario, there is an HVDC path to the Pacific Northwest, which brings wind from Montana and North Dakota and acts as an alternative wind import option for NWUS-W. There is also an MT-HVDC link from BASN to the east that offers an alternative export destination to NWUS-W. As a result, the BASN-NWUS-W interface has a flatter average flow but a wider standard deviation in Figure 36, driven by the increased variations in available flow patterns.

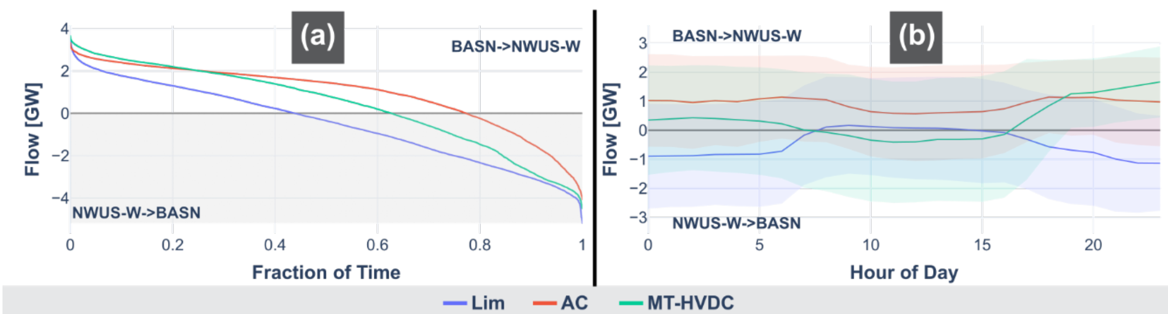


Figure 36. Interface between Basin and Pacific Northwest

Panel (a) flow duration curve and panel (b) average weekday shape with ±1 standard deviation shaded.

4.2.3 HVDC links between the Western and Eastern Interconnections are highly used and exhibit geographically dependent bidirectional flows

The 20 GW of HVDC capacity added between the Western and Eastern Interconnections in the MT-HVDC scenario is used substantially, as illustrated in the flow duration curves of Figure 37, where flat portions represent operation at the limit. All four HVDC links connecting the Western and Eastern Interconnections in the MT-HVDC scenario move power in both directions—importing to the Western Interconnection and exporting from it. The degree of bidirectionality varies geographically: larger in the north and south and lesser in the middle between ROCK and SPP.

The northernmost connection between Montana and North Dakota exhibits a light diurnal pattern. At times, power flows west-to-east during the day when there is much solar PV available in the West and the link offers an alternative sink for wind. During the evening and nighttime, the flow is predominantly east-to-west as also seen in the storage-like behavior of HVDC for the West in Section 4.2.1. The southernmost seam, between DSW and SPP-South, exhibits a strong diurnal pattern and is evenly split between daily west-east and nightly east-west flows.

The ROCK region, containing Colorado and parts of Wyoming, has two connections to the Eastern Interconnection via SPP-North and SPP-South. In both, power flows predominantly west-to-east, although east-to-west flows make up around 10% of the time. This is likely because of ROCK's weaker connection to the rest of the Western Interconnection, making it easier to send power east versus west.[57]

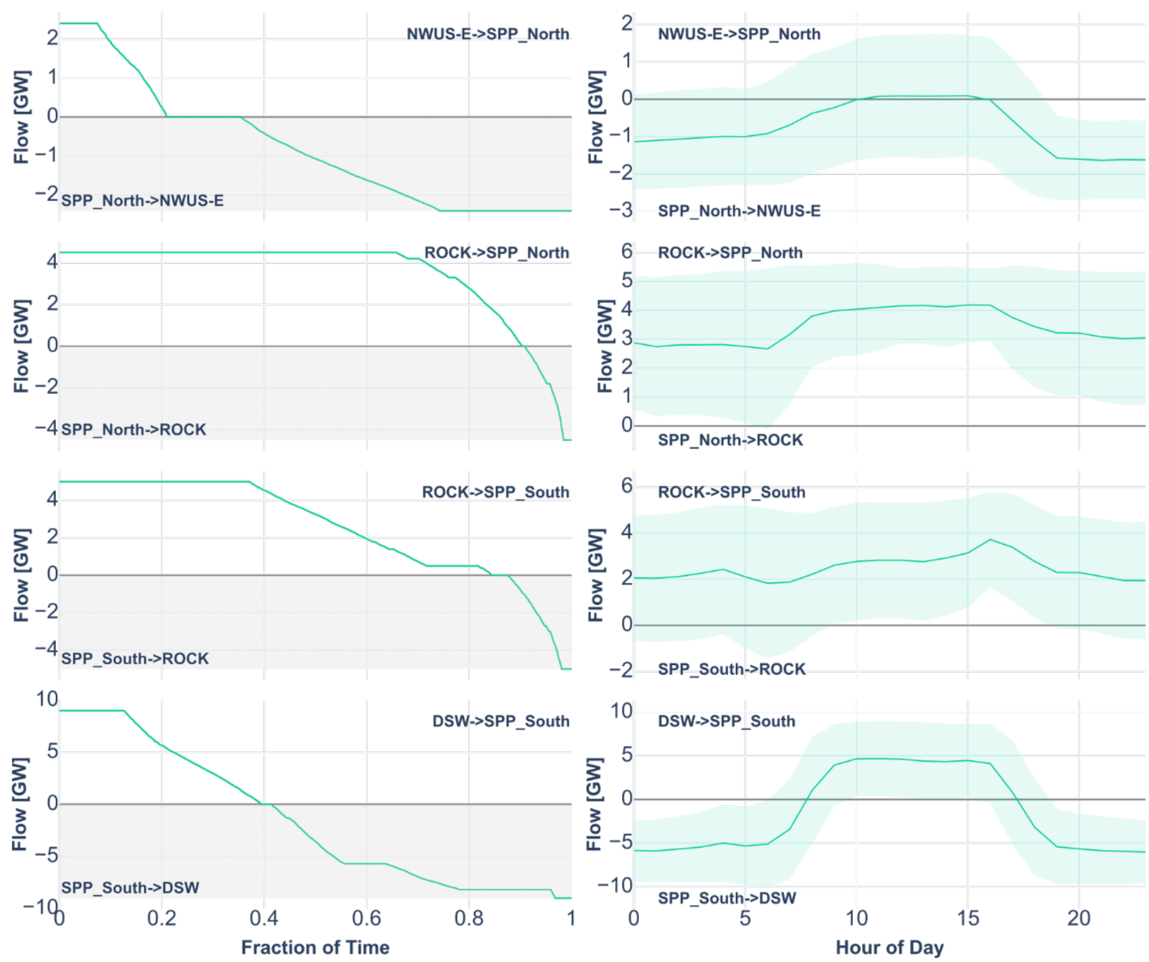


Figure 37. Flow duration curve (left) and average weekday across four Western-Eastern Interconnection seam corridors

4.3 Economic Analysis Indicates Benefits From More Interregional Transmission in the Considered Scenarios

This section highlights the avoided costs and other economic benefits estimated from the earlier nodal scenarios modeled. The metrics presented are the avoided costs and benefits to the Western Interconnection only. The results compare the three earlier nodal scenarios modeled—Limited, AC, and MT-HVDC—and the results may not

[57] The MT-HVDC buildout from the plains eastward is much more extensive than the buildout in the west. Therefore, issues around weak connections on the Eastern Interconnection side are more robustly addressed. Details of the full HVDC expansion are available in Appendix B.5.

generalize to other transmission scenarios or portfolios. Grid planners will need to conduct comprehensive nodal economic analysis as potential transmission projects are planned and implemented. Because these results use earlier scenario input assumptions, the estimates differ from the zonal economic analysis presented in Chapter 2 of the NTP Study that uses final scenario input assumptions. The economic results demonstrate interregional transmission could provide cost savings to the grid.

4.3.1 Increased transmission capital cost expenditures in the studied interregional scenarios coincide with lower generation capital costs

The transmission costs for the Limited scenario total $46.2 billion including a 17.5% adder for an AFUDC. The added transmission for the AC scenario totaled $55.1 billion. The transmission costs for the MT-HVDC are $80.0 billion for transmission lines and converter stations including the AFUDC. The study team estimated costs for each set of transmission lines using the WECC Calculator (Black & Veatch 2019). Table 8, Table 9, and Table 10 include the total number of lines, total line miles, average cost per mile, and the total cost for each case.

Table 8. Transmission Capital Cost for the Limited Scenario

	Number of Lines	Total Mileage	Costs ($B)
Right-of-Way Cost	220	10,373	0.2
Transmission Line Cost	220	14,905	39.1
Total Cost			46.2

Table 9. Transmission Capital Cost for AC Scenario

	Number of Lines	Total Mileage	Costs ($B)
Right-of-Way Cost	232	11,971	0.2
Transmission Line Cost	232	18,447	46.7
Total Cost			55.1

Table 10. Transmission Capital Cost for the MT-HVDC Scenario

	Number of Lines	Total Mileage	Costs ($B)
Right-of-Way Cost	225	15,164	0.2
Transmission Line Cost	225	24,594	53.6
Converter Station Costs			14.5
Total Cost			80.0

Table 11, Table 12, and Table 13 list the costs by voltage class to show the differences across the scenarios considered. The Limited scenario contains the highest 230-kV costs because of its higher reliance on intraregional expansion. The 500-kV costs dominate the AC scenario as the primary mode of interregional expansion used. Finally, HVDC transmission drives the MT-HVDC scenario costs.

Table 11. Cost by Mileage and Voltage Class for the Limited Scenario

kV	Circuit Count	Circuit Miles	Right-of-Way Cost ($M)	Transmission Lines ($B)	Cost/Mile ($M)	Total Cost ($B)
230 AC	50	1,731	20.0	2.5	1.7	3.0
345 AC	68	3,585	22.1	6.9	2.3	8.1
500 AC	185	9,590	128.8	29.8	3.7	35.1

Table 12. Cost by Mileage and Voltage Class for the AC Scenario

kV	Circuit Count	Circuit Miles	Right-of-Way Cost ($M)	Transmission Lines ($B)	Cost/Mile ($M)	Total Cost ($B)
230 AC	29	972	20.0	1.5	2.1	1.7
345 AC	54	3,844	24.7	7.4	2.6	8.7
500 AC	149	13,591	137.5	37.8	3.9	44.6

Table 13. Cost by Mileage and Voltage Class for the MT-HVDC Scenario

kV	Circuit Count	Circuit Miles	Right-of-Way Cost ($M)	Transmission Lines ($B)	Cost/Mile ($M)	Total Cost ($B)
230 AC	30	725	16.5	1.0	1.7	1.2
345 AC	92	7,667	33.2	13.3	2.0	15.7
500 AC	88	8,526	67.1	23.8	3.3	28.0
500 HVDC	15	7,676	48.7	29.7*	4.6	35.0

**Includes converter stations*

ReEDS output for 2022–2034 provides the basis for the generation capital costs.[58] The values obtained from ReEDS were in 2004$ and escalated to 2018$ using the Consumer Price Index. The total generation capital costs are $211.3 billion for the Limited scenario. The AC and MT-HVDC costs decrease to $163.0 billion and $151.8 billion, respectively, which is $48 billion and $59 billion less than the Limited scenario.

4.3.2 Operating costs decrease with increased interregional transmission, resulting in greater net annualized benefits

Table 14 shows the overall annual production avoided costs. The annual operation costs for the Limited, AC, and MT-HVDC scenarios are $9.6 billion, $7.6 billion, and $5.5 billion, respectively. Thus, the AC scenario has avoided costs of $2.0 billion annually whereas the MT-HVDC has avoided costs of $4.1 billion. The reduction in fossil fuel use in the AC and MT-HVDC scenarios drives the majority of these avoided costs. In addition to the reduction in fossil fuel usage, there is a change in the renewable resource mix. The Limited scenario relies more on solar and storage, which results in larger ITC payments to solar generators compared to the other scenarios. Annualized ITC payments to solar are $2.7 billion for the Limited scenario, $2.3 billion for the AC scenario, and $2.0 billion for the MT-HVDC scenario. The reduction in solar is offset with an increase in wind generation in the AC and MT-HVDC scenarios, largely in the eastern regions of the Western Interconnection. The PTC payments are $7.8

[58] Generation costs are not split out by resource type.

billion in the Limited scenario, $9.9 billion in the AC scenario, and $12 billion in the MT-HVDC scenario.

Table 14. Summary of Annual Savings Compared to the Limited Case

	AC	MT-HVDC
Annual fuel and other operating costs	$2.0 Billion	$4.1 Billion
Annual subsidy to wind (PTC)	-$2.1 Billion	-$4.2 Billion
Annualized subsidy to solar + storage (ITC)	$0.4 Billion	$0.7 Billion

The overall net avoided costs are estimated by adding the savings from transmission capital costs, generation capital costs, and operational costs. The study team annualized these avoided costs to enable their addition because operational avoided costs are expected to accrue annually whereas the capital costs are paid once and provide infrastructure with a lifetime of many years. The study team used annualized avoided costs instead of the net present value of avoided costs because the operating costs are estimated from simulations of a single year (2035). The formula used to annualize the avoided costs is as follows (Becker 2022):

$$Annualized\ Cost = C \times \frac{r(1+r)^n}{(1+r)^n - 1}$$

Where *n* is the lifetime of the investment, *r* is the discount rate, and *C* is the cost being annualized. The study team assumed the lifetime of transmission capital is 40 years and the lifetime of generation capital is 20 years. The results are estimated using two discount rates—3% and 5%—to show the range of avoided costs across different discount rate assumptions. Table 15 shows the total net annualized avoided costs of the AC scenario and MT-HVDC scenario and provides net annualized avoided costs above the Limited scenario across the range of discount rates. The MT-HVDC scenario delivers greater net annualized avoided costs than the AC scenario for each discount rate used.

Table 15. Total Annualized Net Avoided Costs of the AC and MT-HVDC Scenarios Compared to the Limited Scenario

	AC		**MT-HVDC**	
	3% ($B)	**5% ($B)**	**3% ($B)**	**5% ($B)**
Annualized Value: Transmission and generation capital, and operating costs	5.0	5.5	**6.6**	**6.9**
Annualized Value: Generation capital and operating costs (transmission capital excluded)	5.4	6.0	8.1	8.9

The study team used the production cost modeling outputs to disaggregate the estimated annual operating avoided costs to estimate benefits accruing to different stakeholders that are part of the grid. The methodology and formulas used in this section are described in more detail in Section 2.6. Note the benefits estimated and identified in this section include direct economic benefits from the electricity system and do not include other benefits such as health benefits from lowered emissions.

The difference in annual profits (revenues-costs) between the two scenarios defines generator benefits. Note capital costs are not included as part of this annual benefit disaggregation. Revenues for each generator are estimated as their LCOE × generation dispatched (TWh); these revenues are shown in Table 16. This calculation assumes LCOE is the price each generator receives under a PPA with a negotiated price at their LCOE.[59] LCOE can be interpreted as the minimum average price a generator requires to attract investment funding, so these results can be considered a lower bound of the benefits to generators. In the AC and MT-HVDC scenarios, the generators function with lower operating costs and lower revenue from power than in the Limited scenario. The reduction in natural gas and other fossil fuel generation drives the lower operating costs. The increase in wind generation, with a lower LCOE and thus less revenue per MWh of power, reduces generator revenues in both the AC and MT-HVDC scenarios. However, wind generators also receive PTC payments and, after including PTC payments to wind generators, the benefits to generators are $1.7 billion higher than in the AC scenario and $0.4 billion lower in the MT-HVDC compared with the Limited scenario (Table 17).

[59] Several studies identify marginal-cost pricing in a highly decarbonized electricity system results in prices that do not provide adequate revenue for generators to recover their costs (Milligan et al. 2017; Blazquez et al. 2018; Pena et al. 2022).

Table 16. Detailed Generation and Revenue by Generator Type

		Limited		AC		MT-HVDC	
Generator Type	**Price Used (LCOE) ($/MWh)**	**Quantity (TWh)**	**Revenue ($B)**	**Quantity (TWh)**	**Revenue ($B)**	**Quantity (TWh)**	**Revenue ($B)**
Nuclear	90.54	45	4.0	45	4.0	51	4.6
Geothermal	57.75	17	1.0	18	1.0	14	0.8
Coal	68.00	16	1.1	10	0.6	6	0.4
Wind: Land-based	22.13	270	6.0	346	7.7	439	9.7
Wind: Offshore	56.87	25	1.4	25	1.4	23	1.3
Solar PV	25.43	442	11	394	9	374	9
Hydro	95.88	166	16	166	16	162	16
Natural Gas (CC)[60]	62.00	111	6.9	86	5.4	60	3.7
Natural Gas (peaker)	157.00	35	5.6	34	5.4	6	0.9
Storage	29.32	144	4.2	118	3.5	74	2.2
Other	68.00	18	1.2	17	1.2	15	1.1
Total		**1,289**	**57.9**	**1,258**	**55.5**	**1,223**	**49.2**

[60] LCOE is computed using the energy generation over the lifetime of the asset. This is fairly consistent year-to-year for wind, solar, and baseload generators. For generators that are dispatchable, such as natural gas, the capacity factor can vary more widely over time. The average LCOE estimates from Lazard (2023) use a capacity factor of 57.5% for gas CC (operating) and 12.5% for gas peaking. The average capacity factors from the NTP scenarios for 2035 only (coming from the PCM simulation) are 26%, 20%, and 13% for CC and 18%, 17%, and 3% for peakers for Limited, AC, and MT-HVDC, respectively. If these capacity factors were assumed to hold for the lifetime of the generators, these gas plants would need larger revenue to achieve full cost recovery. These larger payments would increase generator benefits (Table 17, Line 2) by $2B in the AC and $9.1B in the MT-HVDC scenario compared to the Limited case and reduce power purchaser benefits (Table 17, Line 6) by an equal amount. Hence, the total benefits would be unaffected by this modeling change. Furthermore, the capacity factors are likely to be different from their simulated 2035 values over the lifetime of the assets. Average lifetime capacity factors would likely be higher than the 2035 snapshot because most of the fleet are not new builds and operating during years with lower renewable penetration.

The revenue to transmission owners is defined as the annual revenue requirements for the transmission capital (Short, Packey, and Holt 1995).[61] The annual revenue requirements are the minimum annual payments required to attract investment funding and should be considered a lower bound on the transmission owners' benefits. The AC and MT-HVDC scenarios provide transmission owners $0.5 billion and $2.0 billion greater revenue, respectively, than the Limited scenario. The AC and MT-HVDC scenarios require more investment in interregional transmission and thus require higher corresponding revenue requirements to the transmission owners to justify the investment.

The benefit to power purchasers is defined as the reduction in payments across the scenarios considered. The production cost model assumes load demand is equal across the scenarios considered, so the quantity and quality of power purchased is equal across the three scenarios. The benefit to power purchasers is the reduction in cost required to obtain the power. Power purchaser cost is the sum of the generator revenue and transmission owner revenue. In the AC and MT-HVDC cases, payments to generators decrease whereas payments to transmission owners increase. In sum, the power purchasers add a benefit of $1.9 billion and $6.7 billion annually under the AC and MT-HVDC scenarios, respectively, compared to the Limited scenario.

The final stakeholder considered is the taxpayers. The wind generators receive PTC payments from taxpayers. The taxpayers' benefit is defined as the avoided cost of tax payments. The negative benefits shown are the result of increased tax costs. The study team assumed taxes are collected when the PTC payments are made and do not formally model a tax system where taxes may be collected at a different time than when the subsidies are distributed. The PTC payments increase by $2.1 billion and $4.2 billion in the AC and MT-HVDC scenarios, respectively, compared to the Limited scenario, so the taxpayers' benefits are -$2.1 billion and -$4.2 billion for the AC and MT-HVDC scenarios.

Overall, these results show, in general, the benefits are distributed among the different stakeholders. The generators experience a negative benefit in the MT-HVDC scenario compared to the Limited scenario. However, renewable generation supplants substantial fossil fuel generation and thus requires less remuneration. Though the taxpayers earn a negative benefit in this disaggregation, they are broadly the same collective of end consumers that will have the total benefits passed on to them through the ratemaking process.

[61] Annual revenue requirement can be computed using the formula $ARR = I \times r(1+r)^n/((1+r)^n - 1)$ where *I* is the initial capital investment, *r* is the discount rate, and *n* is the number of annual payments expected. The values shown use r = 5% and n = 40 years.

Table 17. Disaggregation of Annual Benefits According to Stakeholders

Stakeholder	Component	Limited ($B)	AC ($B)		MT-HVDC ($B)	
		Scenario	Scenario	Benefit*	Scenario	Benefit*
Generators	1. Gen cost	9.6	7.6	-2.0	5.5	-4.1
	2. Gen revenue from power	57.9	55.5	-2.4	49.2	-8.7
	3. Gen revenue from PTC	7.8	9.9	2.1	12	4.2
	4. Total gen benefit (2+3-1)	56.1	57.8	1.7	55.7	-0.4
Transmission Owners	5. Transmission owner revenue	2.7	3.2	0.5	4.7	2.0
Power Purchasers	6. Payment to generators for power	57.9	55.5	-2.4	49.2	-8.7
	7. Payment to transmission owners	2.7	3.2	0.5	4.7	2.0
	8. Total load purchaser benefit -(6+7)	-60.6	-58.7	1.9	-53.9	6.7
Taxpayers	9. Payment for PTC	7.8	9.9	2.1	12	4.2
	10. Total taxpayer benefit (-9)	-7.8	-9.9	-2.1	-12	-4.2
	Total (4+5+8+10)	-	-	2.0	-	4.1

** The benefit for the Interregional and MT-DC scenarios is defined as the difference between the benefits of that scenario and the Limited AC scenario. Total benefits are not shown for the individual scenarios because they have practical meaning only when two scenarios are compared.*

5 Conclusions

This chapter documents the nodal scenario development, which includes several rounds of production cost modeling and DC power flow steady-state and contingency analysis as well as select economic analysis for the NTP Study. This nodal analysis across three scenarios (Limited, AC, and MT-HVDC) is designed to accomplish two primary objectives: 1) verify the scenarios are feasible given network and operational constraints and 2) provide insights about the role of transmission operations for a range of transmission topologies.

The results of this chapter demonstrate transformative scenarios, where large expansions of new interregional transmission significantly change the operational relationships between transmission planning regions, can reach 90% decarbonization by 2035, and pass preliminary reliability tests, such as select single contingencies. The nodal transmission expansions show long-distance, high-capacity HV and EHV transmission effectively moves power from more remote areas toward load centers, enables bidirectional power transfers between regions, and can also play critical roles in day-to-day balancing intraregionally and interregionally and between nonadjacent regions. Also apparent in developing the three nodal expansions is that transmission can adapt to different types of futures—those that have more local generation such as the Limited scenario, and the interregional expansion scenarios (AC and MT-HVDC), where longer-distance and higher-capacity transmission is deployed. Substantial transmission expansion was required in all the nodal scenarios modeled for this study.

Transmission buildout scenarios using multiterminal and potentially meshed HVDC technology represent the lowest-cost scenarios. However, the magnitude of additional interregional transmission capacity arising from these scenarios is far advanced from existing regional transmission planning and merchant transmission schemes. HVDC network solutions will also require additional strengthening of intraregional AC networks. Moreover, the HVDC scenarios present opportunities for seam-crossing HVDC transmission between the Eastern, Western, and ERCOT interconnections. Study results show this interregional HVDC transmission infrastructure is heavily used.

Limited interregional expansion scenarios can be operated reliably; however, they differ from the AC and MT-HVDC scenarios by having greater local generation ramping and balancing needs (greater need for dispatchable capacity, including clean thermal generation, which exhibits greater variable costs considering fuel needs).

The methods developed for the transmission portfolio analysis are novel in that they could be applied at a large-geographic scale and include both production cost modeling and rapid DC-power-flow-informed transmission expansions. The incorporation of capacity expansion modeling data was also innovative. This is not the first example of closely linking capacity expansion modeling to production cost and power flow models in industry or the research community, but several advancements were made to realistically capture the various network points-of-interconnection for large amounts of wind and solar, build out the local collector networks if necessary, and validate interregional solutions factor in the local transmission challenges that might arise from scenarios that reach 90% reduction in emissions by 2035.

5.1 Opportunities for Further Research

The methods to model the U.S. electricity system with network-level detail and with highly decarbonized systems stretch the data management and computational limits of many methods typically used for power system analysis. In addition, this study reveals many assumptions about the large-scale transmission expansions and power system operations that could be strengthened with further study:

- **Visualization:** Modeling CONUS results in huge amounts of data to manage. Visualization tools have helped the study team rapidly assess the success of a transmission line development or the placement of renewable resources on the network. But additional work on visualizing these systems should continue to be an area of research to speed analysis and allow for easier stakeholder interactions.
- **Network formulations:** Improvements in the representation of network constraints in nodal production cost models should allow improved computational efficiency of branch flow constraints for an increased number of HV/EHV transmission elements.
- **HVDC dispatch strategies and interregional coordination:** Further implement different strategies for the dispatch of point-to-point, embedded HVDC links and MT or meshed HVDC networks in nodal production cost models.
- **Interregional coordination:** Undertake the evaluation of day-ahead and real-time interregional coordination algorithms implicitly considering information asymmetry and uncertainty between balancing areas (plant outages, wind/solar production, and demand).
- **Power flow control devices:** Improve the representation of at-scale grid enhancing technologies (GETs) and power flow controlling device capabilities (e.g., phase-shift transformers and static synchronous series compensators).
- **Direct integration of AC power flow:** Integrating AC power flow across scenarios (see Chapter 4) by adding a stage to the transmission expansion workflow could improve the solutions. However, more work would be needed to develop robust model linkages where feedback from AC power flow could rapidly inform development decisions.
- **Durable contingency sets:** Develop further methods to identify critical contingency sets for various configurations of the future contiguous U.S. grid under many contingency conditions.

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Appendix A. Methodology

A.1 Nodal Datasets

Table A-18. Summary of Nodal Baseline Datasets for Contiguous United States (CONUS)

Quantity (000s)	Eastern Interconnection	Western Interconnection	ERCOT	CONUS
Nodes	95.9	23.9	6.8	**126.8**
Branches (lines/cables/trafos)	115.7	28.1	8.4	**152.3**
Loads	41.2	14.6	3.7	**59.6**
Generators	10.8	4.3	0.7	**15.5**

ERCOT = Electric Reliability Council of Texas

Table A-2. Overview of Data Sources Used for Building CONUS Datasets

Description	Eastern Interconnection	Western Interconnection	ERCOT
Network topology (node/branch connectivity)[1]	MMWG 2031[2]	WECC ADS 2030 v1.5	EnergyVisuals[5]
Node mapping (spatial)	NARIS	NARIS/EnergyVisuals	NARIS
Generation capacity (technology)	NARIS	WECC ADS 2030 v1.5	NARIS
Generation techno-economic characteristics[3]	NARIS, EIA CEMS	WECC ADS 2030	NARIS
Demand	EER	EER	EER
Hydro (energy constraints)[4]	NARIS	WECC ADS 2030	NARIS
Variable renewable energy (VRE) time series	reV	reV	reV

[1] Augmented through stakeholder feedback to include the most recent available data on network updates/additions.

[2] ERAG Multiregion Modeling Working Group (MMWG) 2031 series.

[3] Includes heat rates, minimum up-/downtimes, ramp rates, and minimum stable operating levels.

[4] Hourly/daily/monthly energy budgets (as appropriate).

[5] Power flow case files (2021 planning cases).

ADS = Anchor Dataset (Western Electricity Coordinating Council, n.d.); CEMS = continuous emission monitoring system; EER = Evolved Energy Research; EPA = U.S. Environmental Protection Agency; MMWG = Multiregional Modeling Working Group; NARIS = North American Renewable Integration Study (National Renewable Energy Laboratory [NREL] 2021b); reV = Renewable Energy Potential Model (Maclaurin et al. 2019); WECC = Western Electricity Coordinating Council

A.2 Benefits and Challenges in Implementation of CONUS-Scale Databases

The benefits of implementing CONUS-scale nodal databases are summarized next:

- **Model fidelity:** Increased model fidelity and insights into operations and transmission use (beyond zonal capacity expansion)
- **Discretization:** Identification of discrete interzonal and intrazonal transmission loading, congestion, and expansion needs (including potential transit needs for nonadjacent regions)
- **Data management:** Enabling more seamless data flow and obtaining information to feed forward and feed back to other modeling domains.

Appreciating these benefits, the challenges in implementation are summarized next:

- **Dataset maintenance:** Consistent maintenance of datasets across regions and interconnects to ensure relevance and accuracy is challenging because each region and interconnection applies different approaches when collating data into aggregated datasets. Similarly, regions within each interconnection have varying levels of alignment with interconnectionwide modeling practices.
- **Dataset updates:** Another challenge that has emerged is the potential time lag to the latest available nodal information (specifically demand, generation capacity, and network topologies), which can result in the potential for perpetual chasing of data. This is not necessarily specific to the National Transmission Planning Study (NTP Study) but should be considered for future similar CONUS-scale work to support repeatability and potential periodic updates of CONUS-scale interregional transmission planning efforts.
- **Effort:** The collation of datasets and model building is a data- and labor-intensive undertaking. The NTP Study has established a structured set of workflows to undertake this in future and address this challenge (in addition to the abovementioned challenges of dataset maintenance and updating).
- **Interregional focus:** There is the potential to overly focus on regionally specific intraregional transmission needs and solutions. This can lead to a false sense of accuracy within regions if one deviates from the primary objectives and drivers of the NTP Study (and other similar efforts)—that is, interregional transmission needs and enabling intraregional transmission needs (transit needs).

A.3 Disaggregation: Adding Generation Capacity to Nodal Models

The process of adding capacity to the nodal model integrates many considerations and is implemented in an internally developed NREL tool called ReEDS-to-X (R2X):

1. Average generator sizes per technology are based on the Western Electricity Coordinating Council (WECC) Anchor Dataset (ADS) data for standard technology-specific generators (Western Electricity Coordinating Council 2022) or the median generator size of the technology in the zone in which it is being added.

2. Nodal injection limits are applied (both for number of units and capacity) to avoid large generator injections and large numbers of generators connected to individual nodes.

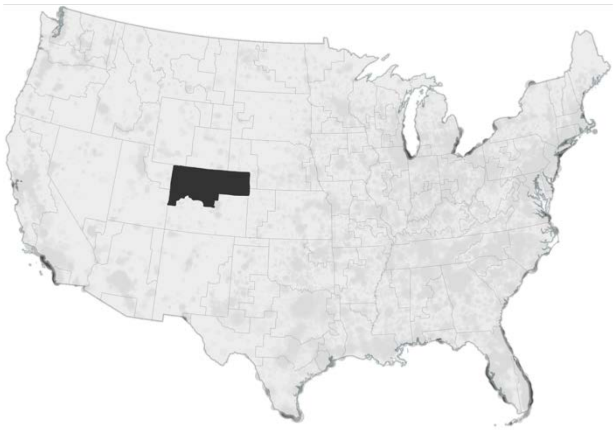
3. For variable renewable energy (VRE) technologies, which use a time series for their characterization (fixed injections), the National Renewable Energy Laboratory (NREL) Renewable Energy Potential Model (reV) (Buster et al. 2023) is used in combination with a k-means clustering technique to aggregate wind and solar photovoltaic (PV) sites to points of interconnection (POIs) (Figure 5).

4. Distributed solar PV is prioritized to nodes with high load participation factors (LPFs), aligning with the expected distributed resource location closer to large loads.

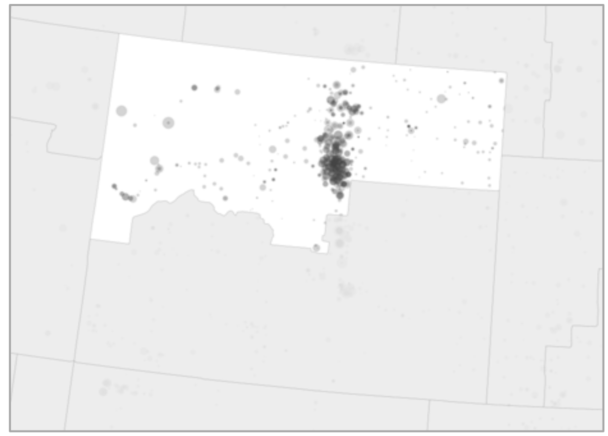
5. Heuristics for battery energy storage systems (BESS) are applied by co-locating 4-hour BESS to solar PV POIs and 8-hour BESS to land-based-wind POIs (with a 50% capacity limit). Following this, any remaining BESS capacity is allocated to nodes with high LPFs.

A.4 Disaggregation: Zonal-to-Nodal Demand

Figure A-1 demonstrates geospatially how a specific Regional Energy Deployment System (ReEDS) zone, highlighted in (a) (Northern Colorado), is disaggregated to the nodal loads within that zone. This is based on the established LPFs of each node for the Northern Colorado zone (shown via the relative size of each of the markers in (b) of Figure A-1).



(a)



(b)

Figure A-1. Illustration of zonal-to nodal (Z2N) disaggregation of demand (a) CONUS and (b) zoom to Colorado

In (a), a single ReEDS zone is highlighted; in (b), a zoom into northern Colorado illustrates individual node load through which LPFs are calculated and zonal ReEDS load is disaggregated.

A.5 Transmission Planning Principles

The NTP Study applies several building blocks for the discrete decisions made about the transmission planning process. Where possible, the following principles are applied to expand both interregional and intraregional transmission:

- **Right-of-way expansion:** Expansion of an existing single-circuit to double-circuit overhead line
- **New corridor:** Expansion of a new double-circuit overhead line
- **Voltage overlay:** The ability to move from established voltages to higher-capacity voltage levels, e.g., 345 kilovolts (kV) to 500 kV
- **High-voltage direct current (HVDC):** Termination into well-interconnected areas of existing alternating current (AC) transmission networks with converters of 2-gigawatt (GW) monopole or 4-GW bipole at a time (further details are provided in Appendix A.6).

The increasingly granular representation of network constraints within the staged transmission expansion process is established through the combined monitoring or bounding of flows across preexisting and new interfaces. The study authors collected existing tie-line interfaces from public sources and stakeholders while defining new interfaces between transmission planning region boundaries (based on the aggregated subtransmission regions in Appendix B.2). In addition, interregional tie-lines were always monitored given the interregional emphasis of the study.

The increasingly granular representation of network constraints that forms part of the zonal-to-nodal transmission expansion workflow is shown in Figure A-2. This staged approach enables the exploration of line loading, congestion, and use to highlight transmission expansion needs while improving model tractability in Stage 1 of the workflow.

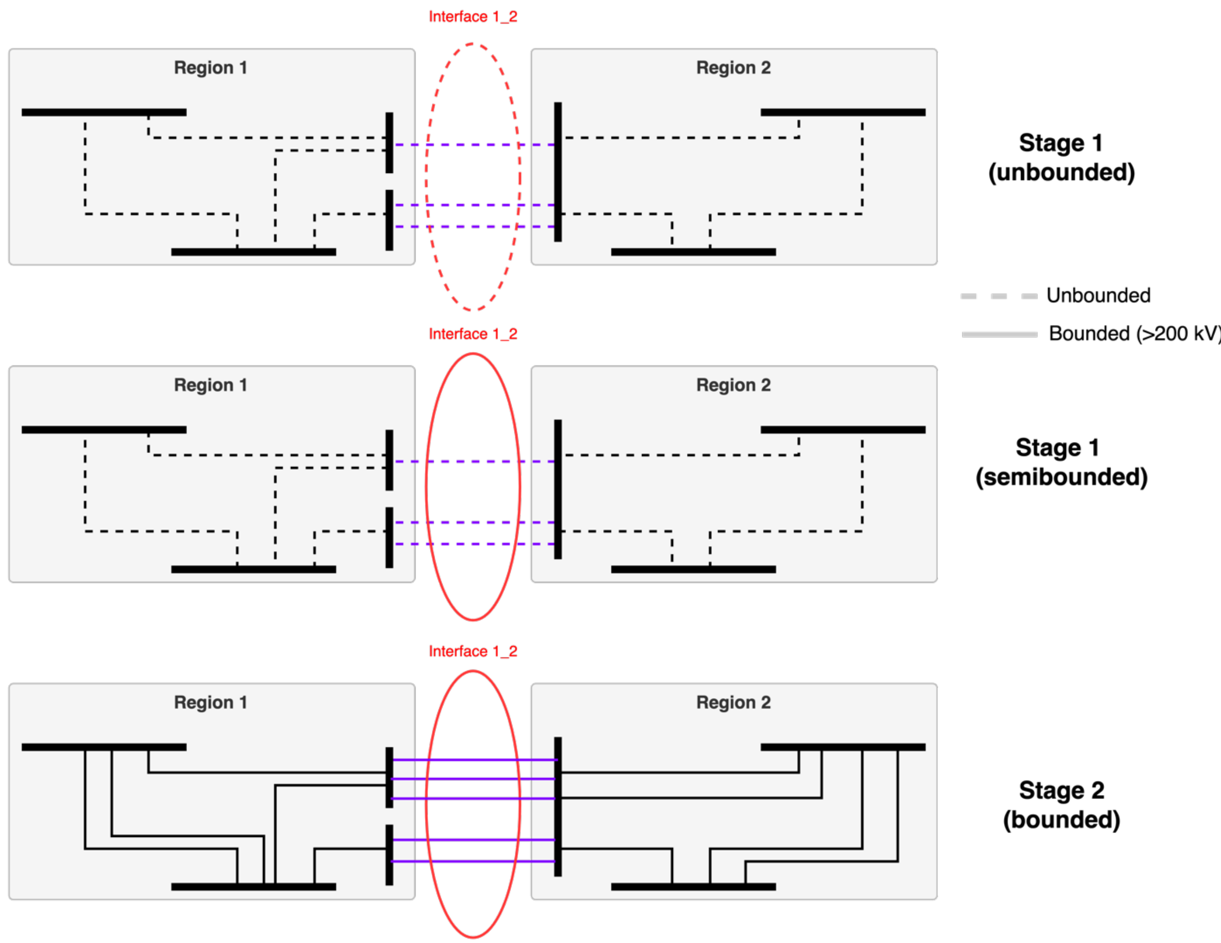


Figure A-2. Illustration of nodal transmission network constraint formulations

A.6 Transmission Planning Approach for HVDC Networks

The unique nature of HVDC network design (notwithstanding classical point-to-point types of HVDC infrastructure) shifts the staged transmission planning (Figure 6) approach slightly for a scenario with large amounts of multiterminal HVDC zonal investments. This approach is outlined next:

1. **Establish a conceptual topology:** Establish an initial HVDC network focused on the building blocks for HVDC. These are assumed as 2-GW monopole and 4-GW bipole pairs at a time. From this, establish appropriate nodes for discrete HVDC links into the combination of large load zones, large concentrations of generation capacity (particularly VRE), and well-interconnected areas of existing HVAC networks with a capability to absorb/evacuate large amounts of power—that is, areas with good network connectivity, higher voltage levels, and strong short-circuit levels (closer to synchronous generators).

2. **Prioritize large interregional transfers:** Although generation and storage capacity are prescribed from zonal capacity expansion findings, interregional transfer capacity is used as a guide for transferring power between regions to maintain practical realizations of HVDC expansion.[62] Hence, there is a distinct prioritization of large interregional zonal transfers (>10 GW) followed by interregional corridors (2–10 GW) and then other potentially smaller corridors (<2 GW).

3. **Stage 1 (nodal production cost model, initial round):** Set interface limits (similar to the approach outlined in Figure 6) but using existing interface limits from zonal capacity expansion findings. Use an initially large HVDC transfer capacity for the HVDC links portion of the scenario (chosen as 10 GW) and run the nodal production cost model.

4. **Stage 1 (nodal production cost model, next round):** Adapt the HVDC overlay limits (from the initially chosen large capacity, 10 GW), undertake potential relocation of termination points of the HVDC overlay as well as scaling the relative size to established building blocks based on the use of the HVDC overlay and rerun the nodal production cost model.

5. **Stage 2 and Stage 3:** Using the findings from the previous steps, undertake HVAC transmission capacity expansion to support the HVDC overlay as defined in the previously discussed workflow in Figure 6 to ensure secure operations and contingency performance for HVAC expansions and large HVDC expansions. As part of this step, there is the potential need to further refine the HVDC overlay topology.

A.7 Snapshot Selection Methodology

When using a power flow model—either as an aid to speed up feedback to model changes or to perform contingency screening—it is necessary to select a set of snapshots to perform the calculation. There are many methods to do this; next is a description of two that were used as part of this study.

Systemwide and region-specific statistics

Table A-3 shows the snapshots characteristics used in the DC power flow transmission planning phase. Using these snapshots resulted in several hundred snapshots per scenario being used to inform the flow impacts of adding different lines.

[62] Building many short-distance HVDC links integrated into a multiterminal HVDC overlay is unlikely to be practical considering the 2035 model year for the zonal-to-nodal translated scenarios—hence, the prioritization approach taken for the zonal-to-nodal translation with respect to HVDC deployment.

Table A-3. Selection of Operating Conditions (“snapshots”) From Nodal Production Cost Model for Use in DC Power Flow Transmission Expansion Planning Step

CONUS	Region-Specific
Load • High load periods	Interregional exchanges • Average period for each regional interface • High inter-tie use (P90)
Renewable energy production • Peak/high wind + solar • Peak/high wind • Peak/high solar	Regional balancing • High import (P90) • High export (P90) • High load
Instantaneous renewable energy • High VRE share in high load period • High VRE share in low load period	Transit flows • High transit flows across “balanced” regions

Note: Region-specific refers to transmission planning subregions.

Flow-based statistics

The following methodology is used to select the snapshots for the Stage 3 contingency analysis in the ReEDS earlier scenario results. The premise of this approach is the snapshots are used for a specific task: to investigate the impact of topology changes on how flow is distributed through the system. In Stage 2, this is because of a change of topology—for example, new transmission lines but fixed injections. In Stage 3, this is because of a line outage and no change of injections. This observation suggests a sample of snapshots whose flow distribution matches the flow distribution over the full year would capture the behavior of interest.

The flow metric used here is the average flow; however, this can be adapted to U75, or other metrics.

Consider a set of branches $b \in \mathcal{B}$, with ratings r_b, and a set of time instances $t \in \mathcal{T}$, which for a year is [1,8760]. The goal is to select a subset of time $\mathcal{K} \subset \mathcal{T}$. Define $f(b,t)$ as a function that returns the flow on branch b at time t, $p(b,\mathcal{T})$ as a function that returns all time instances $t \in \mathcal{T}$, where the flow on b is positive and similarly $n(b,\mathcal{T})$ as a function returning all time instances where flow on b is negative. Crucially, note all flows are known a priori because a solved production cost model is available.

The average positive and negative flows on branch b are calculated as

$$\bar{b}_{+} = \frac{1}{r_b|\mathcal{T}|} \sum_{t \in p(b,\mathcal{T})} f(b,t), \qquad \bar{b}_{-} = \frac{1}{r_b|\mathcal{T}|} \sum_{t \in n(b,\mathcal{T})} f(b,t).$$

These values are combined for all branches into a vector $\vec{b}$. Similarly, the estimated branch flows based on the snapshots are defined as

$$b_{+}^{\star} = \frac{1}{r_b K} \sum_{t \in p(b,\mathcal{T})} u_t \cdot f(b,t), \qquad b_{-}^{\star} = \frac{1}{r_b K} \sum_{t \in n(b,\mathcal{T})} u_t \cdot f(b,t).$$

Here, $K = |\mathcal{K}|$ is the number of desired snapshots and u_t is a binary variable (8,760 variables in total). All these variables are combined into a single vector, $\vec{b}^{\star}$. So only K snapshots are selected, the following constraint is enforced:

$$\sum_{t \in \mathcal{T}} u_t = K.$$

Finally, the objective function is

$$\text{Minimize}_{\vec{b}^{\star},\vec{u}} \left\| \vec{b}^{\star} - \vec{b} \right\|_1$$

minimizing the L_1 norm of the difference between the vector of average flows over all time instances and the one calculated for just the selected $t \in \mathcal{K}$. The selected snapshots are those where $u_t = 1$ at the end of the optimization.

A.8 Alternative Approach for Contingency Analysis for Western Interconnection Focused Analysis

The methodology for contingency analysis for the earlier scenarios for the Western Interconnection (results presented in Section 4) is modified from that explained in Section 2.3. The method employed incorporates single contingencies into the production cost model, turning the formulation into a security-constrained one. First, a DC-power-flow-based contingency analysis is performed as a screen on selected single contingencies, as described previously. The violations are pared down to the worst violations that must be addressed. For example, if a particular line overloads in several snapshots by a significant amount but is otherwise not very highly used, the question of where the right place to add transmission quickly becomes rather complex. The result is a limited set of security constraints comprising a handful of single line contingencies with a small number of monitored affected elements per contingency. These are added to the production cost model and a new year simulation is performed A benefit of the security-constrained approach is the results contain congestion costs associated with the contingency constraints, which makes it possible to sort and rank the constraints based on their impact to the problem objective. The costliest security constraints are the most valuable to upgrade for the system. Where the congestion cost is low, the security constraint can be maintained, and no further action taken. This methodology is demonstrated on the Western Interconnection cases, because the GridView tool—used to solve these models—can incorporate such security constraints. Note as the case sizes increase, so does the computational burden of contingency constraints. Depending on the number of security constraints considered and the model size, there may be a point where the computational costs outweigh the benefits of this approach.

A.9 Impact of Branch Monitoring on Transmission Expansion Workflow in Earlier ReEDS Scenarios

For the simulations conducted on the Western Interconnection footprint only (Limited and AC scenarios), the limits of all branches with voltage rating 230 kV and above were enforced, or approximately 4,000 branches. In the Multiterminal (MT)-HVDC scenario, the limits on all branches with voltage rating 345 kV and above are enforced, as well as select 230-kV branches observed to violate their limit, for a total of ~6,000 branches. All flows on branches 230 kV and above are recorded, however, and as shown in Figure A-3 the resulting violations are not very significant (~1%).

Figure A-3. Branch loading in the MT-HVDC scenario

Chart shows branches rated ≥200 kV and ≥250 megavolts-ampere (MVA) that violate their nominal rating. Despite not enforcing all branches as in the Western Interconnection only cases, the number of violations remains quite small (at only 1%).

The number of enforced lines in the earlier scenarios is a factor of 2–4 greater than in the final scenarios. This results in greater sensitivity of generator dispatch to the changing topology, i.e., transmission expansion. A consequence of the increased sensitivity is the DC power flow step in Stage 2 (cf. Section 2.3) of the transmission expansion becomes more challenging to interpret because an underlying assumption of iteration with the DC power flow is an unchanged generation dispatch. Therefore, the DC power flow is not relied on in Stage 2 in the earlier ReEDS scenarios. On the other hand, in Stage 3, where select single contingencies are considered, the DC power flow is still used extensively as a valuable contingency screening tool. The methodology for selecting representative snapshots is described under flow-based statistics in this appendix.

A.10 Design Approach for a Nationwide MT-HVDC System in Earlier ReEDS Scenario (demonstrated in Section 4)

Modeling large MT-HVDC systems, embedded in AC interconnects, in production cost models is an emerging area (Nguyen et al. 2024). The flows within each MT-HVDC system are determined by shift factors, very similar to the power transfer distribution factors (PTDFs) in the linearized AC system. Converter models are added as control variables that link AC and DC buses.

The objective of the MT-HVDC scenario is to explore the implications of a large-scale MT-HVDC system covering a large portion of the country. A design decision on the earlier ReEDS scenarios is to use a single design that would facilitate combining segments. All new HVDC lines modeled in this scenario are ±525-kV voltage source converter (VSC) bipole design with conductor parameters adapted from the CIGRE Working Group (WG) B4.72 DC Benchmark Models (CIGRE WG B4.72 2022, 804). The rating of a single bipole does not exceed 4.2 GW.

Converter stations are sited based on the underlying AC system. They are embedded in the AC system at comparatively strong/well-meshed locations to enable delivery to/from the DC system as well as provide a viable alternative path during contingency events. Converter locations can be grouped into three categories: VRE hubs, load centers, and connection points to AC transmission hubs.

HVDC transmission is generally chosen for two key reasons: high power transfer over large distances and flow controllability. MT-HVDC systems have the benefit of fewer converters than point-to-point systems and therefore lower capital costs; meshed MT-HVDC systems have the additional advantage over radial systems of reliability under failure because of alternative current paths. Reduced converter count in MT-HVDC systems comes at the cost of increasing mismatch between line and converter rating, depending on whether each converter on the line operates as a source or a sink. Reliability in meshed MT-HVDC systems comes at the cost of some loss in controllability because the flow distribution between parallel paths will be the function of shift factors, similar to the AC system.

The design choice in the MT-HVDC scenario presented in Section 4 of this chapter is a compromise between the costs and benefits of the three frameworks described previously. First, several MT-HVDC systems that are largely radial are created. At their intersections, they do not share a DC bus but rather an AC bus between a pair of converters,[63] as shown in Figure A-4. This solution sacrifices some of the cost saving of MT-HVDC, because of the additional converter, but gains back more controllability while maintaining the reliability of a system with multiple paths for power to flow. The final HVDC topology is presented in Figure A-5, which shows HVDC expansion color coded to highlight the separate MT-HVDC systems.

[63] Note a converter here actually refers to the converter pair ±525 kV, given the bipole design.

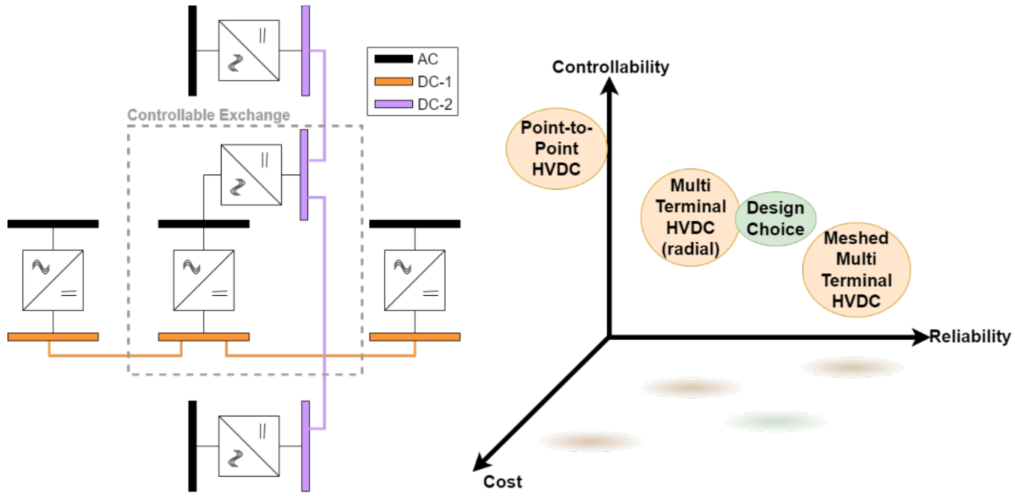


Figure A-4. Coupled MT-HVDC design concept and rationale

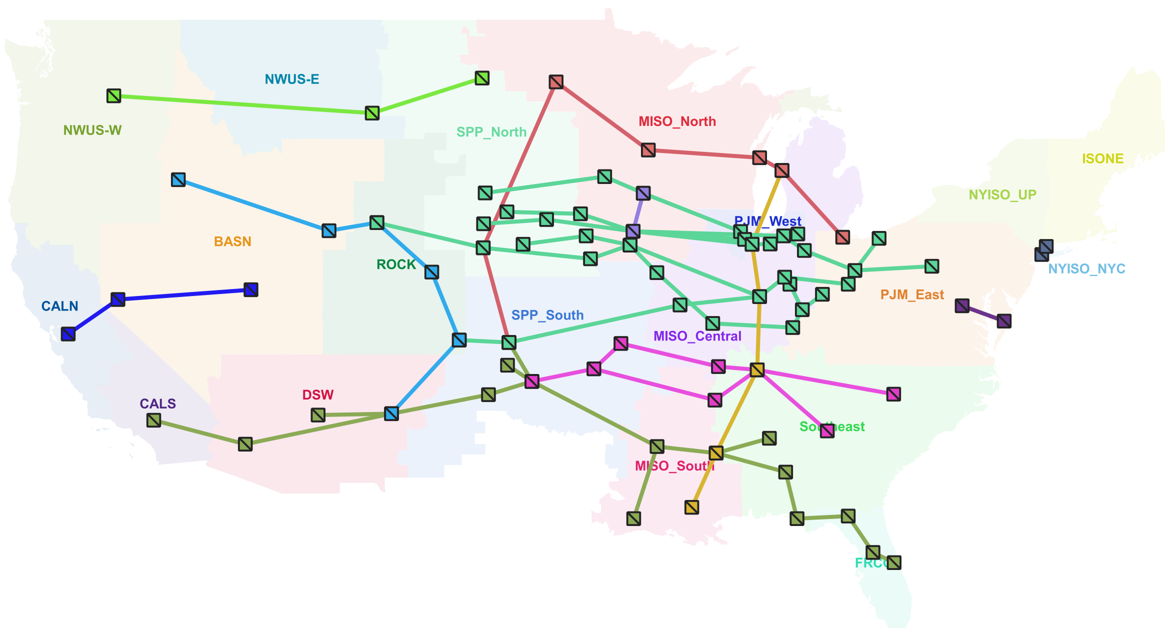


Figure A-5. HVDC buildout in the MT-HVDC scenario

Different colors correspond to separate MT-HVDC systems interconnected via the AC system as illustrated in Figure A-4.

Appendix B. Scenario Details

B.1 New Transmission Network Elements

Table B-1. Nodal Transmission Building Block Characteristics (overhead lines)

Voltage (kilovolts [kV])	Conductor	Pos. Seq. R (ohms per kilometer [Ω/km])	Pos. Seq. X (Ω/km)	Rate (MVA)	Source
230 kV	2 x Bluejay	0.0299	0.3462	703	(1)
345 kV	2 x Bluejay	0.0299	0.3579	1,055	(1)
345 kV	3 x Bluejay	0.02	0.3127	1,566	(1)
500 kV	4 x Grosbeak	0.0259	0.3145	2,187	(1)
500 kV	4 x Bluejay	0.0152	0.3105	3,027	(1)
500 kV	6 x Bluejay	0.0102	0.2186	3,464	(1)
765 kV	6 x Bluejay	0.0105	0.2831	5,300	(1)
HVDC (525 kV)	Bobolink	0.0099	N/A	2,100	(2)

Sources:

Empresa de Pesquisa Energética (EPE) (2022)

CIGRE WG B4.72 (2022)

Table B-2. Nodal Transmission Building Block Characteristics (transformation capacity)

Voltage (kV)	X (p.u. on Transformer MVA base)	Rate (MVA)
345/230	0.12	2,000
500/230	0.12	2,000
500/345	0.12	2,000
765/500	0.12	2,000

In the earlier ReEDS scenario results, an analysis of transformers in the Western Electricity Coordinating Council (WECC) starting case (2030 Anchor Dataset [ADS]) shows the relationship between transformer MVA base and per unit reactance on the system basis could be approximately described as

$$x[\text{p.u.}] = 0.0523 \ln(MVA) - 0.2303.$$

This formula is used to calculate variable reactance, under the assumption the transformer base and rating are equal.

Converter losses are estimated on a per unit basis as

$$R[\text{p.u.}] = \text{loss}_{\%}/P_{\text{Rated[MW]}}$$

Where 0.7% is assumed for line-commutated converter (LCC) technology and 1.0% for voltage source converter (VSC) technology. Though the production cost models are conducted without losses, these values are important for the downstream power flow models in Chapter 4, where a full alternating current (AC) power flow that includes losses is conducted.

B.2 Region Definitions

Figure B-1. Subtransmission planning regions (derived and aggregated from Regional Energy Deployment System [ReEDS] regions)

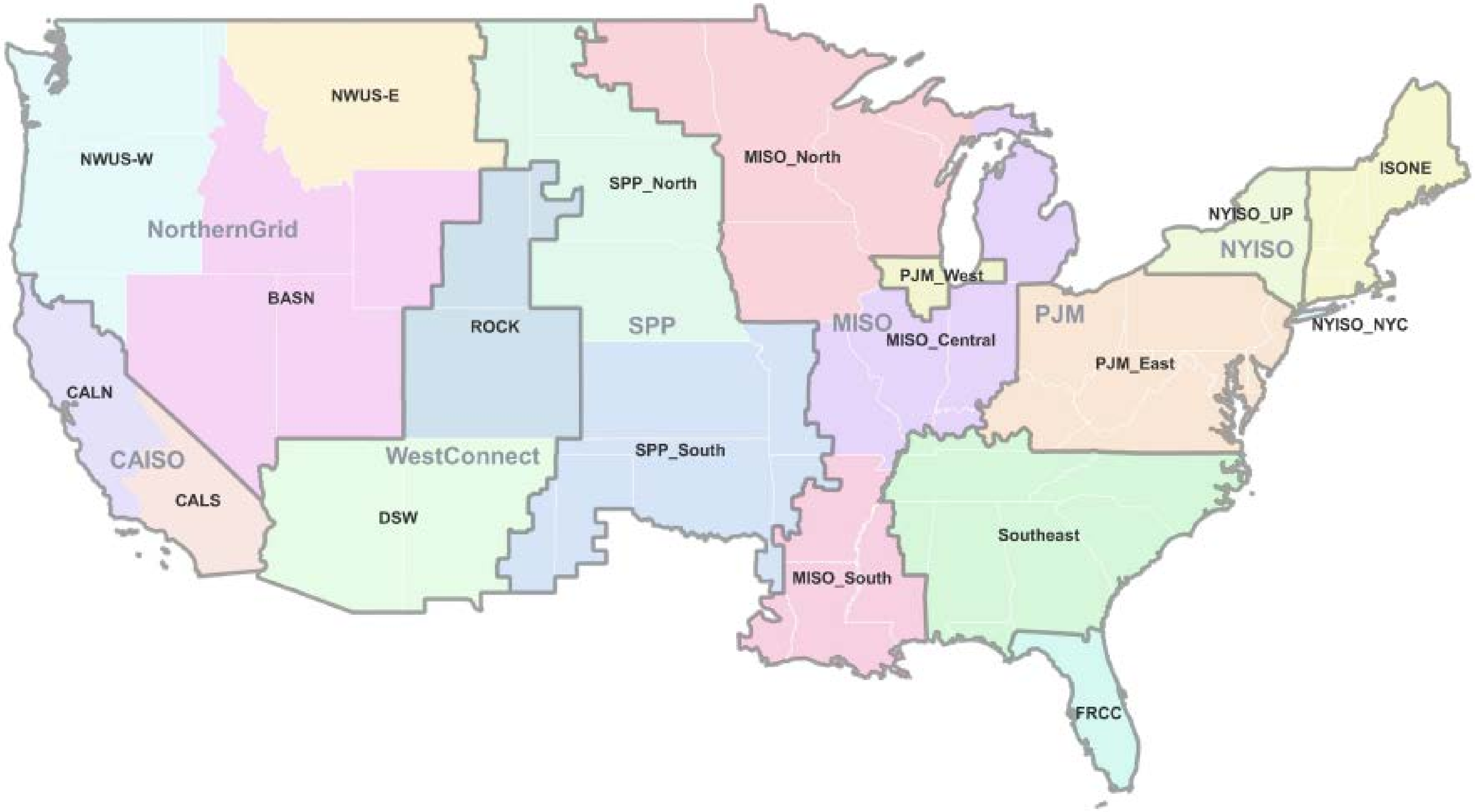


Figure B-2. Subregion definitions used in Section 4 (earlier ReEDS scenario results)

The definition of regions is based on the underlying 134 ReEDS regions (excluding Electric Reliability Council of Texas [ERCOT] regions).

B.3 Detailed Motivation for Transmission Expansion for Earlier ReEDS Scenarios

The following sections describe the key transmission additions and their rationale on a regional basis. For the Western Interconnection footprint, comparisons between the scenarios are given whereas for the Eastern Interconnection regions, the description is for the Multiterminal (MT) High-Voltage Direct Current (HVDC) scenario only.

California (CALS and CALN)

All scenarios have some intraregional transmission expansion, particularly in southern California to help the large amount of solar power get to load. Northern California has a few 500-kilovolt (kV) backbone changes associated with offshore wind integration that are based on plans in California Independent System Operator's (CAISO's) 20-year outlook.[64]

In the interregional scenario, the connection to the Desert Southwest (DSW) and Basin region is strengthened both via Nevada as well as along the southern border. This is mirrored in the MT-HVDC scenario with an MT-HVDC connection to the Lugo substation. In the interregional scenario, a 500-kV backbone on the eastern part of the state is added to increase the transfer capacity between northern and southern California. In all cases, the transmission is primarily motivated by bringing external resources *into* California, primarily eastern wind. However, the transmission capacity also serves to *export* California solar energy during the daily peaks.

Northwest (NWUS-W and NWUS-E)

In all scenarios, some form of a 500-kV collector system is added to collect wind in Montana and attach it to the Colstrip 500-kV radial feed. In the two AC cases, a new line from Garrison to Midpoint is used to provide an alternative export to WECC Path 8 and a connection to the Gateway projects. In the MT-HVDC case, WECC Path 8 is effectively reinforced with an MT-HVDC line connecting North Dakota and the Ashe substation in Washington, with a terminal in Colstrip in between.

Desert Southwest (DSW)

The desert southwest is one of the more varied regions in terms of transmission, driven by very different resource buildouts between the scenarios. In the limited AC scenario, the region has substantially (≥20 GW) more solar capacity installed than the other two cases. The 500-kV system along the southern border is reinforced and expanded to collect that solar energy and bring it to load. In the interregional scenario, substantially more wind (~11 GW) is installed, predominantly in New Mexico, necessitating a significant 500-kV backbone expansion. The energy is provided in three main paths: north via Four Corners, west via Coronado, and south toward Phoenix. The MT-HVDC scenario has a lower solar build, like the interregional AC scenario, and a wind build somewhere between the Limited and interregional scenarios. As a result, the AC expansion is not as extensive as the interregional scenario but taken together with the

[64] https://stakeholdercenter.caiso.com/RecurringStakeholderProcesses/20-Year-transmission-outlook

DC scenario forms a similar three-corridor design to get both New Mexico wind as well as wind from across the seam to the Eastern Interconnection toward the western load pockets.

A commonality between all scenarios is the reinforcement of the 500-kV corridor across northern Arizona into Nevada. This is driven by the ability of the transmission to carry both solar from southern Utah/northern Arizona that is present in all scenarios as well as the wind out of New Mexico via Four Corners when present.

Rocky Mountain (ROCK)

The 345-kV system around Denver is expanded to bring in predominantly wind resources. To the south, the Colorado Power Pathway[65] is part of the augmented starting case and is expanded on in the scenarios. To the north, connections to the Cheyenne and Laramie River region in Wyoming are added. Two paths are generally used—one to the Public Service Company of Colorado and one to the Western Area Power Administration systems.

The Gateway projects are also added in all scenarios as part of the augmented starting case. They are expanded in all scenarios to collect more of the Wyoming wind. In the limited AC case, with less wind, this is done with mainly 230-kV reinforcements. In the interregional AC and MT-HVDC cases, a northern 500-kV section is added between the Windstar and Anticline substations.

The TransWest express[66] DC and AC projects are incorporated into the augmented starting case and bring wind from Wyoming toward the Desert Southwest and California.

The Rocky Mountain region is loosely connected to the rest of the Western Interconnection compared to the other regions. One of the key differences between the limited AC scenario and the others is the connection between the Rockies and other regions. In the interregional AC scenario, there is a connection to New Mexico via the 500-kV backbone built to collect wind. In the MT-HVDC scenario, an HVDC backbone connects the Rocky Mountain region to the Basin via Wyoming, to the Desert Southwest via New Mexico, and to Southwest Power Pool (SPP) to the east.

Basin (BASN)

In the modeled scenarios, the Basin region plays a key role in providing multiple paths for resources to reach load. The projects involving the Basin region largely begin/end in other regions: Montana, Rocky Mountain, Desert Southwest, Pacific Northwest, or California and are therefore not repeated here. The MT-HVDC scenario builds on this connector role for the Basin with two east-west corridors: one toward the Pacific Northwest and one toward the Bay Area in California.

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[65] https://www.coloradospowerpathway.com/
[66] https://www.transwestexpress.net/

SPP

The transmission expansion in SPP is focused on the east and west movement of wind but some solar in the southern areas as well. To that end, multiple HVDC corridors begin in the SPP footprint and move east or connect across the seam to the Western Interconnection. In addition, a north-south corridor connects to Midcontinent Independent System Operator (MISO) and allows resources to shift between the various east-west corridors. Finally, the wind in the southern part of SPP is intended to complement solar in both Florida and California via an MT-HVDC corridor stretching from coast to coast along the southern part of the country.

In addition to the MT-HVDC, a complementary 345-kV collector backbone is added along the north-south axis on the SPP footprint. The intention is to both collect the VRE resources and provide an alternative path under contingency events.

A 500-kV loop interconnects with MISO in the southern end of the footprint as an alternative path east for wind resources in SPP and to provide better access to load and the MT-HVDC system for solar resources in MISO.

MISO

An MT-HVDC system runs north-south along MISO's eastern portion to provide exchange between solar- and wind-rich regions as well as a path to the Chicago, Illinois load center. The east-west MT-HVDC corridors originating in SPP include multiple terminals in MISO to serve load and collect further resources toward the east. The east-west corridors terminate at three types of destinations: load centers in PJM and the southeast, solar hubs in PJM and the southeast, or strong 765-kV substations in PJM's footprint that can carry the power farther east to the coast.

In terms of AC expansion, Tranch 1[67] additions are added to the MISO footprint along with further reinforcements of the 345-kV system.

PJM

The MT-HVDC connections to PJM are largely described in the SPP and MISO sections. It is noted here Chicago serves as an MT-HVDC hub for several east-west lines as well as the north-south MISO system. Finally, the north-south SPP MT-HVDC system loops east and terminates in PJM between Toledo, Ohio and Cleveland, Ohio.

Some of the 765-kV segments of the PJM system are upgraded to enable eastward transfer of more power coming from the MT-HVDC systems.

Along the Eastern Seaboard, there is a new DC link across the Chesapeake Bay and a 230-kV collector system for solar and offshore wind between Delaware and Maryland.

[67] https://cdn.misoenergy.org/MTEP21%20Addendum-LRTP%20Tranche%201%20Report%20with%20Executive%20Summary625790.pdf

Southeast

Beyond the MT-HVDC systems terminating in the southeast, as described in the SPP and MISO sections, 500-kV reinforcements are built to connect predominantly solar resources to load or the MT-HVDC overlay. Examples are 500-kV connections between Panama City, Mobile, and Montgomery, Alabama and lines from Charlotte, North Carolina down to Augusta, South Carolina.

FRCC

An MT-HVDC link connects FRCC to the southeast and farther west, intended to import wind from the middle of the country during the night and export the Florida sun in the middle of the day. In addition, a 500-kV backbone is extended from the central Florida region north to further collect solar resources in the northern part of the state and get them toward load centers on the coasts and to the south.

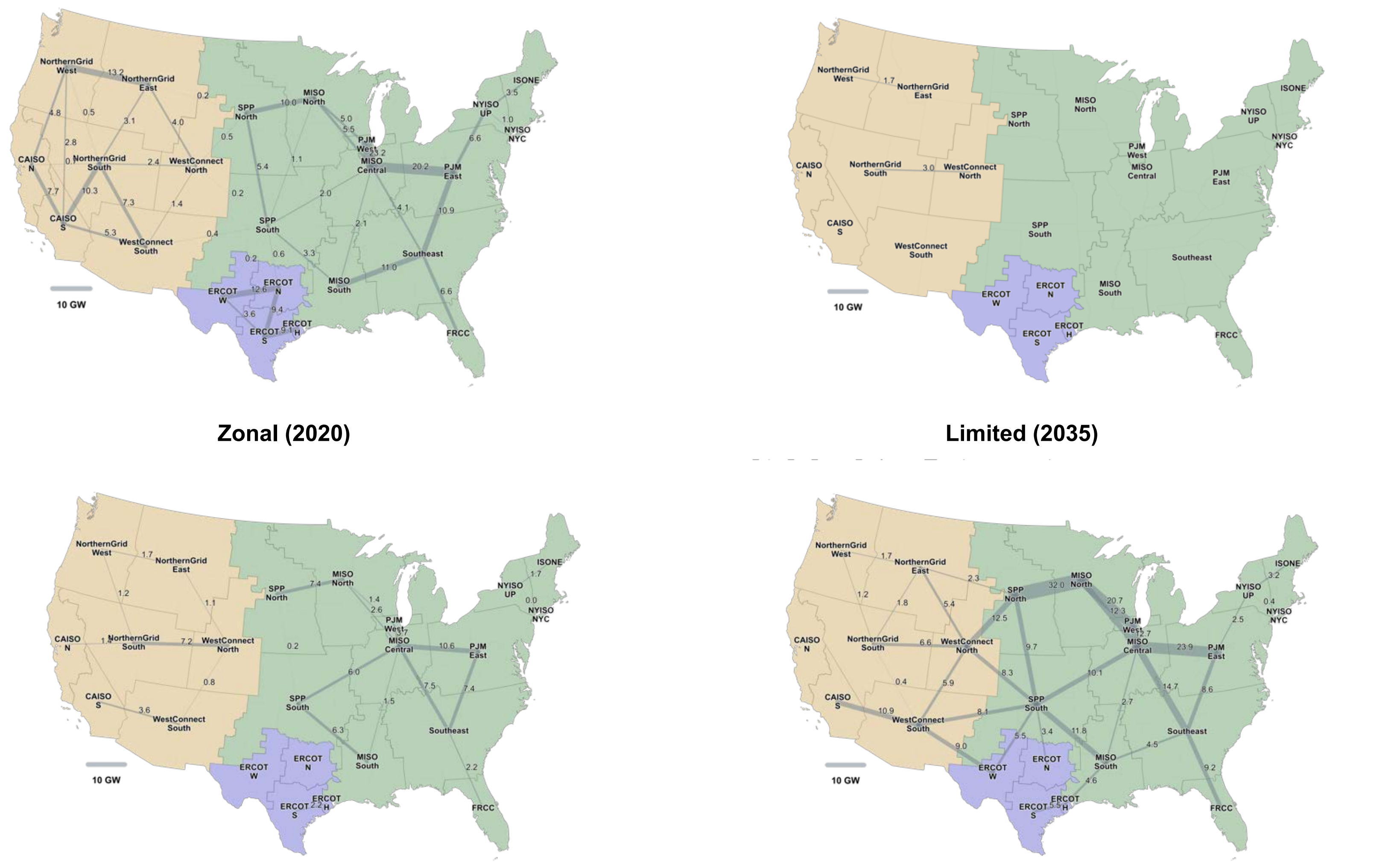
NYISO

A new HVDC link connects Long Island, New York to Connecticut. Several 345-kV upgrades are also performed on Long Island to accommodate offshore wind projects. The Northern NY Priority, Champlain-Hudson Power Express, and Clean Path NY are also added by default to augment the starting case.

ISONE

Here, 345-kV collector systems are added in Maine, New Hampshire, and Vermont to collect new wind and solar resources and connect them to the existing 345-kV backbone.

B.4 Further Detailed Results for Final Scenarios



Zonal (2020)

Limited (2035)

AC (2035)

MT- HVDC (2035)

Figure B-3. Interregional transfer capacity from zonal ReEDS scenarios

Aggregated to transmission planning regions (some larger regions are further subdivided to aid in planning).

Detailed installed capacity (by scenario)

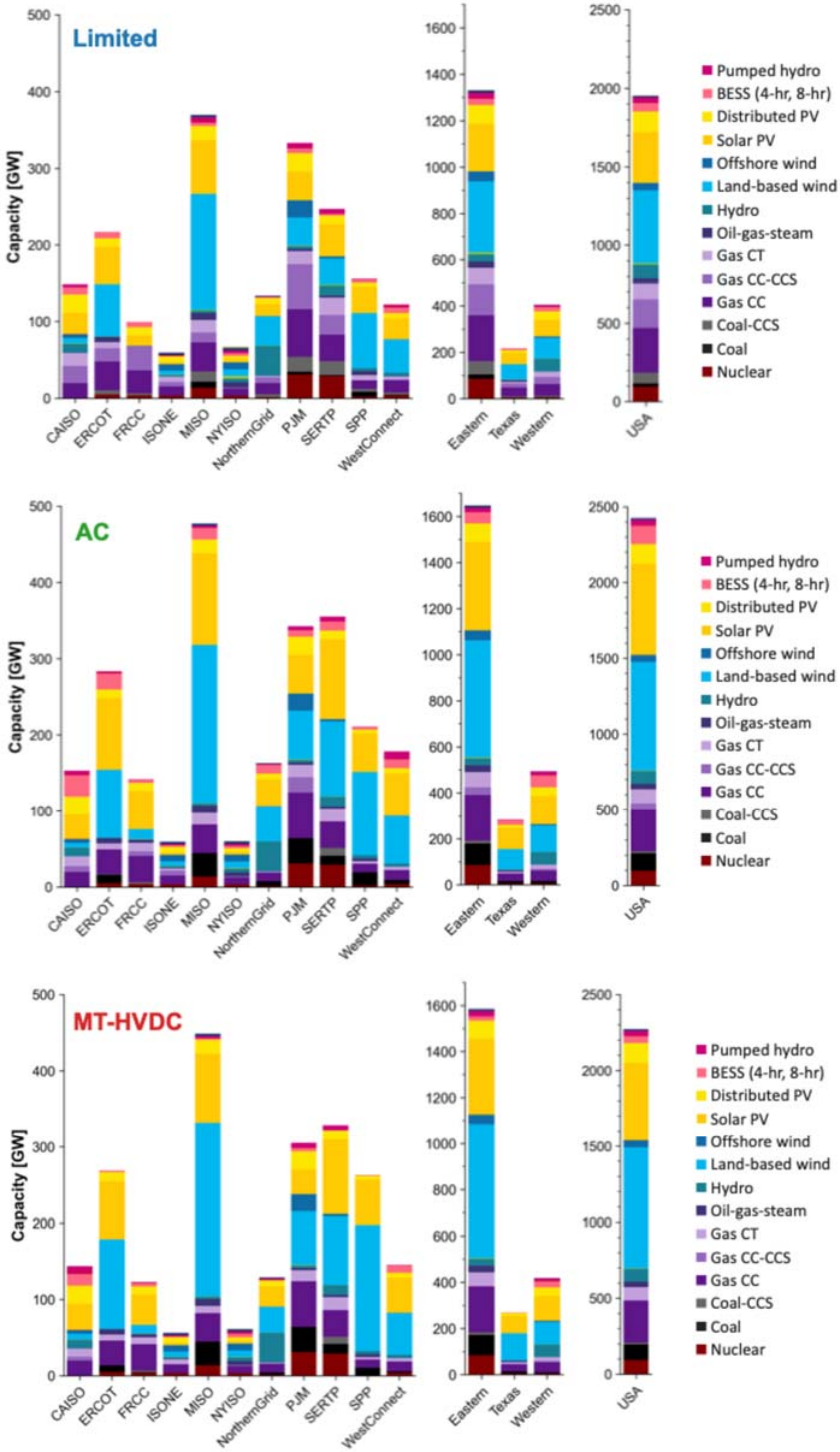


Figure B-4. Summary of installed capacity by transmission planning region, interconnection and contiguous U.S. (CONUS)-wide

Nodal scenarios transmission expansion summary

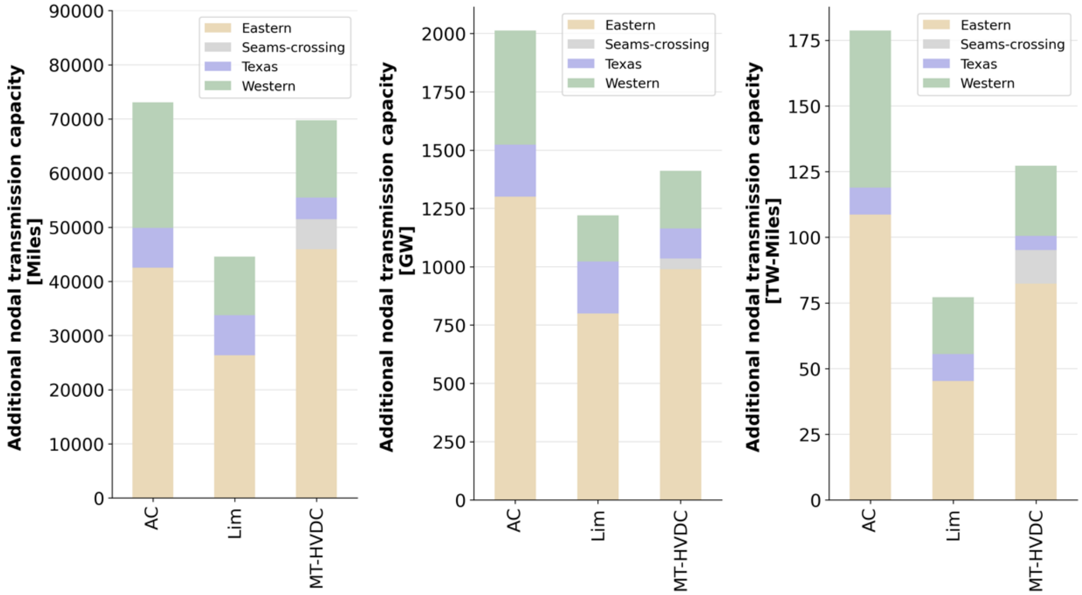


Figure B-5. Summary of nodal transmission expansion portfolios

Shown for AC, Limited, and MT-HVDC scenarios in terms of circuit-miles (left), thermal power capacity (middle), and terawatt-miles [TW-miles] (right).

Detailed nodal scenarios transmission expansion motivation

Table B-3. Rationale for Nodal Transmission Portfolios (Limited scenario)

Interconnect	Transmission Planning Region[1]	Summary
Eastern Interconnection	FRCC	- Significant solar photovoltaics (PV) expansion in the central-eastern side of Florida with large amounts of existing natural gas capacity remaining online - Localized integration of new solar PV capacity does not require interregional transmission expansion with the Southeast - Exiting 500-kV and 230-kV networks suffice for this scenario
Eastern Interconnection	ISONE	- Predominantly solar PV and offshore wind integration to the southern parts of New England - No new 345-kV expansions necessary with New York Independent System Operator (NYISO)
Eastern Interconnection	MISO	- Inclusion of MISO Long-Range Transmission Planning (LRTP) Tranche 1 (several new 345-kV lines) across MISO-N and MISO-C (prescribed expansion) - 345-kV reinforcements in southern part of MISO-C and 500-kV reinforcements in MISO-S to accommodate integration of new wind and solar PV capacity - Additional 345-kV reinforcements in weak parts of MISO-N to strengthen existing network to integrate predominantly new wind capacity and move power east-west toward load centers in MISO-N and PJM-W

Interconnect	Transmission Planning Region[1]	Summary
		- Reinforcement of selected parts of the existing 765-kV network in MISO-C to integrate with PJM-E and PJM-W
Eastern Interconnection	NYISO	- Addition of prescribed transmission (Northern NY Priority, Champlain-Hudson Power Express, and Clean Path NY) - Strengthening of existing 500-kV links in NYISO-NYC with PJM - 345-kV expansion to move power across to Long Island - Selected parts of NYISO-NYC 230-kV localized strengthening of existing circuits to enable solar PV integration - 345-kV strengthening NYISO-UP (upstate) from Buffalo toward PJM (north-south) and new 345-kV along the edges of Lake Erie toward Cleveland
Eastern Interconnection	PJM	- Development of a 500-kV overlay (double-circuit) in Maryland/Delaware area to support integration of large volumes of offshore wind and solar PV - Strengthening of existing single-circuit 500-kV paths (north-south) in New Jersey and Pennsylvania and parts of Virginia - East-west Pennsylvania 500-kV strengthening of existing single-circuits increasing transfer capacity between 345-kV, 500-kV, and 765-kV networks - Strengthening of many of the existing single-circuit 765-kV network in the PJM-East footprint (Ohio, West Virginia, Virginia) to increase transfer capacity with MISO-Central and PJM-West footprints - Selected strengthening of 345-kV networks in single-circuit to double-circuit at the confluence of the 345-kV, 500-kV, and 765-kV networks in PJM-East as well as interregionally with MISO-Central - Imports into the PJM-West footprint are enabled by some single-circuit to double-circuit strengthening of 345-kV networks within PJM-West and links to MISO-Central
Eastern Interconnection	Southeast[2]	- Large amounts of meshed single-circuit to double-circuit 500-kV network strengthening in Tennessee, Mississippi, and Alabama (less strengthening in Georgia and the Carolinas) - Several new double-circuit 500-kV between Alabama and Georgia - Relatively strong 230-kV networks in the Carolinas and Georgia enable integration of expected solar PV, but some 230-kV single-circuit to double-circuit strengthening is needed in southern parts of Alabama and South Carolina
Eastern Interconnection	SPP	- Reinforcement of 345-kV network north-south in SPP-North to accommodate integration of new wind capacity - Some localized 230-kV strengthening to collect relatively large amounts of wind capacity - Expansion of 345-kV network in SPP-South to integrate large amounts of wind and solar PV capacity and move power west-east and further into the central parts of SPP toward seams with MISO-Central - Pocket in SPP-South with large amounts of wind and solar PV (Texas panhandle and eastern edge of New Mexico)

Interconnect	Transmission Planning Region[1]	Summary
		require substantial 230-kV strengthening and 345-kV exports north toward Kansas and west-east to Oklahoma
Western Interconnection	CAISO	- CAISO-North expansion of 500-kV to integrated offshore wind and solar PV combined with strengthening of existing single-circuit 500-kV routes - Selected 230-kV expansions in CAISO-North to integrate solar PV and enable power to move south toward load centers
Western Interconnection	NorthernGrid	- In addition to prescribed Boardman-Hemingway, Greenlink Nevada, and TransWest Express, additional 500-kV double-circuit between Wyoming and Montana is added to move large amounts of wind capacity from Wyoming - Strengthening of 500-kV path on the NorthernGrid West edge (single-circuits to double-circuits) in Oregon for parts of offshore wind integration and as an additional path for power from wind in Wyoming and Idaho
Western Interconnection	WestConnect	- 500-kV expansion from Wyoming north-south toward Colorado, including extensive 230-kV strengthening to collect large amounts of wind capacity - Further 345-kV and 230-kV expansion in CO (in addition to Colorado Power Pathway) to enable further paths for large amounts of wind capacity farther south toward New Mexico and Arizona - 345-kV strengthening in WestConnect South (single-circuits to double-circuits) moving wind and solar PV capacity east-west toward load centers in Arizona and California - Additional 500-kV path created between New Mexico and Arizona also to move large amounts of wind and solar capacity
ERCOT	ERCOT	- Several new double-circuit 345-kV expansions from West Texas toward Dallas-Fort Worth (west-east) and southeast toward San Antonio and Austin - Further strengthening of existing 345-kV single-circuit routes similarly moving large amounts of wind capacity toward load centers - Northern parts of ERCOT also further strengthened with new double-circuit 345-kV expansions also moving large amounts of wind capacity from northern parts of ERCOT and solar PV from eastern parts of Texas toward load centers in Dallas-Fort Worth - Several new double-circuit 345-kV north-south expansions between Dallas and Houston and links to San Antonio and Austin created to further move west Texas wind capacity and solar in south Texas to load centers

[1] *Using transmission planning regions mapped from 134 planning regions in ReEDS (capacity expansion tool).*

[2] *SERTP/SCRTP*

Table B-4. Rationale for Nodal Transmission Portfolios (AC scenario)

Interconnect	Transmission Planning Region[1]	Summary
Eastern Interconnection	FRCC	- Large amounts of solar PV capacity are supported by relatively strong existing 230-kV networks, but additional strengthening in central and southern parts of the Florida Reliability Coordinating Council (FRCC) footprint are needed - New double-circuit 500-kV interregional links created to the Southeast region (Florida to Georgia) to enable large interregional power flows between FRCC and the Southeast
Eastern Interconnection	ISONE	- Strengthening of existing single-circuit 345-kV to double-circuit 345-kV between Independent System Operator of New England (ISONE) and NYISO (upstate) – Massachusetts – New York, Connecticut – New York - Additional 345-kV strengthening between Maine and New Brunswick
Eastern Interconnection	MISO	- Large amount of 345-kV expansion (north-south) along Lake Michigan to move substantial wind capacity toward load centers - Large amounts of further 345-kV strengthening in MISO-North on seams with SPP-North - Two new 500-kV double-circuit overlays (west-east) in MISO-North up to SPP-North seams to move large wind and some solar PV capacity across Minnesota and Wisconsin as well as Iowa and Nebraska to load centers in Illinois - Two new 500-kV double-circuit overlays in MISO-Central with additional double-circuit (north-south) to linking MISO-Central and SPP-South moving large amounts of wind capacity (predominantly for west-east transfers) but with supplementary new 500-kV overlay (north-south) improving contingency performance from Kansas to Missouri and Illinois - MISO-Central requires substantial strengthening of the existing 345-kV networks (in addition to prescribed LRTP Tranche 1 projects) to integrate substantial wind and solar PV capacity while creating critical enabling links between SPP and PJM-East footprint (mostly single-circuit to double-circuit expansion) - Strengthening of the existing 765-kV networks in Indiana (MISO-Central) as a backbone for moving wind and solar PV into PJM-West as well as into PJM-East footprints; no new 765-kV rights-of-way required - Large amounts of wind capacity are integrated and moved west-east via new 500-kV voltage overlays in MISO-South to interconnect with SPP-South and the Southeast region as well as strengthening of existing 500-kV ties with MISO-South and the Southeast

Interconnect	Transmission Planning Region[1]	Summary
		- Substantial amount of 230-kV strengthening in MISO-North (Minnesota and North Dakota); all single-circuit to double-circuit expansions
Eastern Interconnection	NYISO	- New double-circuit 345-kV overlay (from 230-kV) in NYISO combined with strengthening of existing 345-kV in NYISO (upstate) Buffalo area with PJM-West - Further strengthening of existing 345-kV interregional link between NYISO (updates) and PJM-West
Eastern Interconnection	PJM	- Development of a 500-kV overlay (double-circuit) in Maryland/Delaware area to support integration of large volumes of offshore wind and solar PV - Large amounts 500-kV single-circuit to double-circuit strengthening along eastern part of PJM-East (Virginia, Pennsylvania, Maryland) enabling further offshore wind integration and moving power—predominantly solar capacity—from the Southeast into PJM-West - Imports into the PJM-West footprint are enabled by some single-circuit to double-circuit strengthening of 345-kV networks within PJM-West and links to MISO-Central - Interregional links strengthened via 345-kV and 500-kV strengthening with NYISO - Central parts of Pennsylvania 345-kV and 500-kV confluence strengthened further (single-circuit to double-circuit) - Many of the existing 765-kV circuits in PJM-West strengthened to enable bulk movement of power interregionally between MISO-Central and the Southeast as well as integration and key links with strengthened 345-kV and 500-kV networks - 500-kV voltage overlay and meshing of existing 345-kV networks in Kentucky to increase transfer capacity with the Southeast region - PJM-West footprint includes strengthening of existing 345-kV circuits (double-circuits) to enable imports from MISO-Central and MISO-North in addition to 500-kV voltage overlay from MISO-North
Eastern Interconnection	Southeast[2]	- Several interregional ties with PJM-East region are further strengthened in addition to new 500-kV double-circuit expansions (North Carolina, Virginia, Kentucky, Tennessee) - Strengthening of existing 500-kV ties with MISO-South to move solar and wind capacity bidirectionally between Southeast and MISO-Central/MISO-South (Tennessee, Arkansas, Mississippi, Louisiana, Alabama) - Construction of an additional 500-kV circuit across existing 500-kV ties with FRCC - Large number of 230-kV intraregional strengthening in the Carolinas considering the large amount of solar PV and wind capacity expanded

Interconnect	Transmission Planning Region[1]	Summary
Eastern Interconnection	SPP	- Large 500-kV voltage overlays in SPP-South (from 345-kV) across five paths into the Texas panhandle, across Oklahoma, up into Kansas and west-east toward Missouri enabling interregional expansion and movement of large amounts of wind capacity to Southeast and MISO-Central. - Similar 230-kV expansions in SPP-South to the Limited scenario in Texas panhandle and parts of New Mexico to export wind capacity north and east toward Oklahoma, Kansas, and Missouri - 500-kV overlay (from 345-kV) in SPP-North to move large wind and solar PV capacity interregionally to MISO-North (west-east) - Extensive 345-kV strengthening in SPP-North (multiple paths) moving power southeast to link with MISO-North 345-kV networks linking to the 500-kV overlay in MISO-North - New 500-kV double-circuit overlays (from 345-kV) increasing interregional transfer capabilities between SPP-North and MISO-North
Western Interconnection	CAISO	- New double-circuit 500-kV paths (x2) in CAISO-North to integrate offshore wind backbone into existing 500-kV north-south paths - Expansion of single-circuit 500-kV circuits to double-circuit 500-kV in main interregional transfer corridor between California and Oregon - New 500-kV double-circuit expansions between CAISO-North and CAISO-South - Extensive strengthening of existing 500-kV paths from Nevada (x4) into California (CAISO-South) enabling imports of large amounts of wind capacity and solar PV capacity from WestConnect and NorthernGrid-South - 500-kV overlay of existing 230-kV networks in CAISO-South with WestConnect-South moving large amounts of solar PV and wind capacity from Arizona and New Mexico
Western Interconnection	NorthernGrid	- New 500-kV to expand the transfer capacity between the West and South - Further strengthening of 500-kV expansions in Nevada (in addition to TransWest Express and Greenlink Nevada) to enable north-south transfer from NorthernGrid-East and NorthernGrid-South - In addition to Boardman-Hemingway, further additional new double-circuit 500-kV paths are created (north-south) moving capacity through Idaho and toward Washington - Strengthening existing east-west 500-kV transfer capacities between Idaho and Oregon (single-circuit to double-circuit)

Interconnect	Transmission Planning Region[1]	Summary
Western Interconnection	WestConnect	in addition to north-south 500-kV strengthening between Oregon and Washington to enable offshore wind integration combined with land-based wind expansion predominantly in Idaho (additional transfer paths) - New 500-kV overlays from 230-kV between NorthernGrid-East and WestConnect (Montana – Wyoming and Idaho – Wyoming) - In addition to Colorado Power Pathway projects (345-kV), further 345-kV additions (east-west) increasing transfer capabilities between Colorado and Utah - 345-kV strengthening between WestConnect-North and WestConnect-South (four-corners) as additional paths for predominantly Wyoming and Colorado wind capacity - Extensive 500-kV strengthening (single-circuit to double-circuit) in WestConnect-South predominantly enabling moving solar PV and wind capacity from New Mexico and Arizona to California - Several 500-kV overlays of existing 345-kV networks in WestConnect-South (New Mexico and Arizona) playing a similar role as 500-kV strengthening (moving wind and solar PV capacity east-west to load centers in Arizona and California)
ERCOT	ERCOT	- Unchanged from Limited

[1] Using transmission planning regions mapped from 134 planning regions in ReEDS (capacity expansion tool).

[2] SERTP/SCRTP.

Table B-5. Rationale for Nodal Transmission Portfolios (MT-HVDC scenario)

Interconnect	Transmission Planning Region[1]	Summary
Eastern Interconnection	FRCC	- 2- x 4-GW bipoles: one FRCC and Southeast and one between FRCC-MISO (South) used for bidirectional power transfers of solar PV (and some wind from nonadjacent regions including MISO and SPP) - Localized 230-kV strengthening in northern, central, and southern parts of Florida integrating large amounts of solar PV capacity - Single-circuit to double-circuit 500-kV expansion between FRCC and Southeast (Florida – Georgia)
Eastern Interconnection	ISONE	- N/A (other than already prescribed transmission expansion)
Eastern Interconnection	MISO	- 2- x 4-GW bipole from northern part of MISO into PJM-West to bring wind capacity from extreme northern (Montana) and central parts (Minnesota) of MISO-North to load centers in PJM-West

Interconnect	Transmission Planning Region[1]	Summary
		- Northern parts of MISO-North require some strengthening of existing 230-kV and 345-kV networks to collect wind capacity for HVDC transfers - Additional 2- x 4-GW bipoles (multiterminal) from central parts of MISO-North into PJM-West and MISO-Central for moving power across MISO and toward PJM-West - Combination of some new double-circuit 345-kV west-east and strengthening of existing paths to support further movement of wind capacity in MISO-North toward PJM-West and MISO-Central - MISO-Central requires additional single-circuit to double-circuit strengthening (Missouri, Indiana, Illinois, Michigan) - Only selected parts of the existing 765-kV networks between MISO and PJM require single-circuit to double-circuit strengthening to enable transfers between HVDC terminals in MISO and PJM - 4- x 4-GW multiterminal HVDC links in MISO-South enable linking between SPP-South, MISO-South, and the Southeast region - 1- x 4-GW HVDC links with ERCOT for exports predominantly of wind and solar PV from ERCOT
Eastern Interconnection	NYISO	- 2-GW monopole between upstate NYISO and PJM increasing exchange capacity between NYISO and PJM - Strengthening of 345-kV east-west transfer capacity across NYISO (upstate) enabling exports from 2-GW bipole - Additional 500-kV strengthening between PJM-West and NYISO (link into existing 345-kV networks in NYISO)
Eastern Interconnection	PJM	- 4- x 4-GW PJM-West – PJM-East, MISO-Central – PJM-East, PJM-East – Southeast link interregionally between MISO, Southeast, and NYISO, predominantly to move wind capacity from MISO (and indirectly from SPP) into PJM - Selected expansion of the existing 765-kV networks enables exports from HVDC terminals, transfers to embedded HVDC terminals, and improved contingency performance in the footprint - New 500-kV overlay as in AC and Limited to integrated offshore wind capacity - Several interregional 500-kV strengthening needs along Eastern Seaboard and between PJM-East and Southeast
Eastern Interconnection	Southeast[2]	- 4-GW bipole linking PJM-East and Southeast to support the combination of large amounts of wind and solar from the Southeast to PJM - 4-GW bipole moving bidirectional power between MISO-Central and the Southeast leveraging wind in MISO and solar PV in the Southeast - 4-GW bipole between the Southeast and SPP-South moving large amounts of wind into the Southeast - Several supporting 500-kV strengthening in Tennessee, Georgia, Alabama, and Mississippi enabling embedded HVDC imports into the Southeast and exports to MISO-Central and PJM-East

Interconnect	Transmission Planning Region[1]	Summary
Eastern Interconnection	SPP	- 2- x 4-GW bipoles between SPP and PJM-West moving large amounts of wind into strong areas of the existing 765-kV and 500-kV networks - 2- x 4-GW multiterminal bipoles moving power north to south within SPP and enabling further transfers from SPP to MISO-Central and the Southeast - 5- x 4-GW and 1- x 2-GW seam-crossing bipoles across several locations in SPP to move power between the Eastern Interconnection and Western Interconnection—four of these with WestConnect and one with NorthernGrid - WestConnect-South and SPP-South HVDC comprises the starting point of meshed HVDC expansions between the Eastern Interconnection and Western Interconnection - 2- x 4-GW seam-crossing HVDC bipoles between SPP-South and ERCOT mostly for bidirectional exchange of complementary wind capacity in ERCOT and SPP-South - New 500-kV overlay west-east in SPP-South enabling improved contingency performance of extensive HVDC expansion in SPP-South and further transfer capacity for wind and solar PV in Oklahoma and Texas panhandle to MISO-South - Several supporting single-circuit to double-circuit 345-kV expansions in SPP (South) to integrate large wind and solar PV capacity as well as improve contingency performance of HVDC expansions
Western Interconnection	CAISO	- 2- x 4-GW HVDC bipoles between CAISO-South and WestConnect-South shifting large amounts of solar PV and wind from Arizona and New Mexico toward California - Similar new 500-KV expansions in CAISO-North for integration of offshore wind as in AC and Limited - The strengthening of existing 500-kV between CAISO-North and CAISO-South enables further increased transfers
Western Interconnection	NorthernGrid	- 1- x 2-GW seam-crossing link between NorthernGrid-East and SPP-North - Single-circuit to double-circuit 500-kV strengthening in NorthernGrid-East and NorthernGrid-West enables similar transfers of wind capacity from Wyoming toward Oregon and Washington - Offshore wind is integrated in Oregon in a similar manner to that of the AC and Limited scenarios
Western Interconnection	WestConnect	- 2- x 4-GW seam-crossing capacity between ERCOT and WestConnect-South as well as 4-GW bipole between Arizona and New Mexico enables the combination of New Mexico and Texas wind and solar PV capacity to be sent toward load centers in Arizona and California - 4- x 4-GW meshed HVDC seam-crossing expansion between WestConnect-South and SPP-South enables a large component of wind and solar capacity between the Eastern Interconnection and Western Interconnection - 2- x 4-GW seam-crossing capacity expansion between WestConnect-North and SPP-North provides for the

Interconnect	Transmission Planning Region[1]	Summary
		remainder of the dominant transfer capability between the Eastern Interconnection and Western Interconnection - Two additional 4-GW HVDC links in WestConnect-North move Wyoming wind toward Colorado and across the seam-crossing HVDC links between WestConnect-North and SPP-North - 4-GW bipole as seam-crossing capacity from WestConnect (New Mexico) to the southernmost parts of SPP - 4-GW bipole moving power within WestConnect toward Colorado and enabling of seam-crossing between WestConnect and SPP-South - Extensive strengthening of the existing 345-kV and 500-kV networks in WestConnect-South predominantly in New Mexico and Arizona support the multiterminal HVDC links between WestConnect, CAISO, and ERCOT - New 500-kV overlay (from 345-kV) and new 500-kV paths between Arizona and New Mexico further supporting HVDC transfers and collection of wind/solar PV capacity
ERCOT	ERCOT	- 2- x 4-GW seam-crossing HVDC bipoles between ERCOT and the Western Interconnection (WestConnect) predominantly moving large amounts of wind and solar power from ERCOT to WestConnect; this supports exports from West Texas and hence a decreased need for 345-kV strengthening or new 345-kV paths - 2- x 4-GW seam-crossing HVDC bipole between ERCOT and MISO-South getting wind from ERCOT into the Eastern Interconnection - 2- x 4-GW seam-crossing HVDC bipole between ERCOT and SPP-South similarly getting wind and solar PV capacity from ERCOT into the Eastern Interconnection - Existing 345-kV strengthening (single-circuit to double-circuit) is concentrated between Dallas-Fort Worth and Houston (north-south) with selected new paths needed and enabled by new double-circuit 345-kV expansions

[1] Using transmission planning regions mapped from 134 planning regions in ReEDS (capacity expansion tool).

[2] SERTP/SCRTP.

B.5 Further Detailed Results for Earlier Scenarios

Curtailment results in the Western Interconnection

Earlier scenarios (Section 4) used curtailment as a key stopping criteria metric during evaluation of the nodal translations. Figure B-6 compares aggregate curtailment numbers from the three scenarios. Curtailment peaks in the second quarter of the year, corresponding to the hydro runoff in the west, which is also a period of relatively low demand.

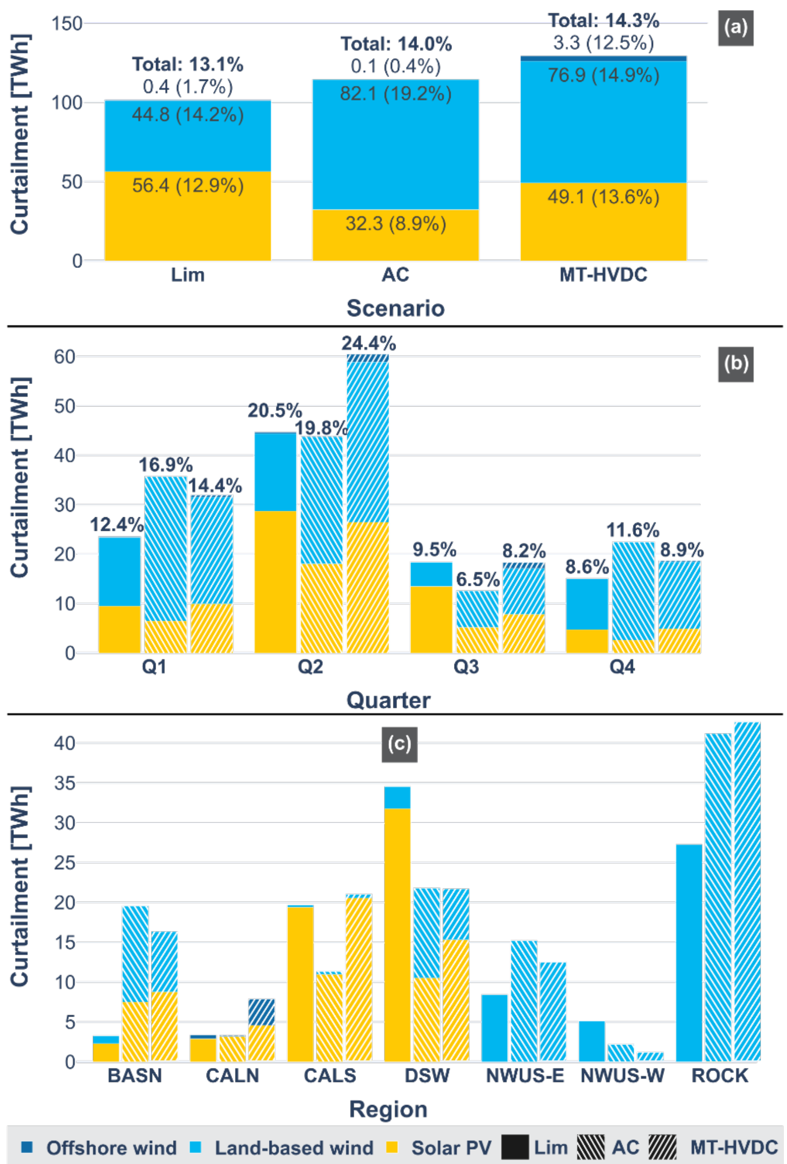


Figure B-6. Curtailment comparison between scenarios in the Western Interconnection

Each panel represents a different level of spatial or temporal aggregation: (a) total curtailment, (b) curtailment by quarter, (c) curtailment by region.

Figure B-7 shows the average weekday curtailment along with standard deviation for the three scenarios. Solar curtailment exhibits a high standard deviation over time because of seasonality or other weather events whereas wind is more consistent on average. As the share of wind increases in the interregional scenarios, it begins to exhibit more of the midday curtailment peak of solar.

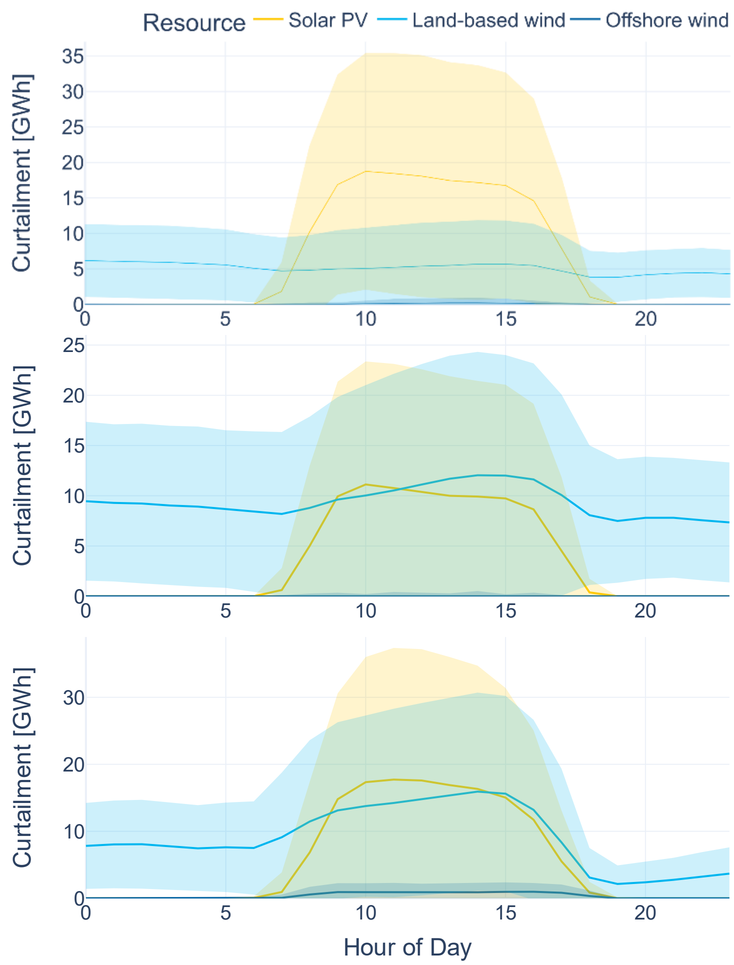


Figure B-7. Relationship between solar and wind curtailment in the Western Interconnection

Average weekday trends shown as lines with standard deviation shaded: Limited (top), AC scenario (middle), MT-HVDC scenario (bottom).

MT-HVDC scenario results for the combined Western and Eastern Interconnections

Figure B-8 shows installed capacity post-nodal disaggregation for the complete MT-HVDC scenario on the combined Western and Eastern Interconnection footprint. Figure B-9 shows the resulting transmission expansion. The HVDC system is divided into several section as described in Appendix A.10.

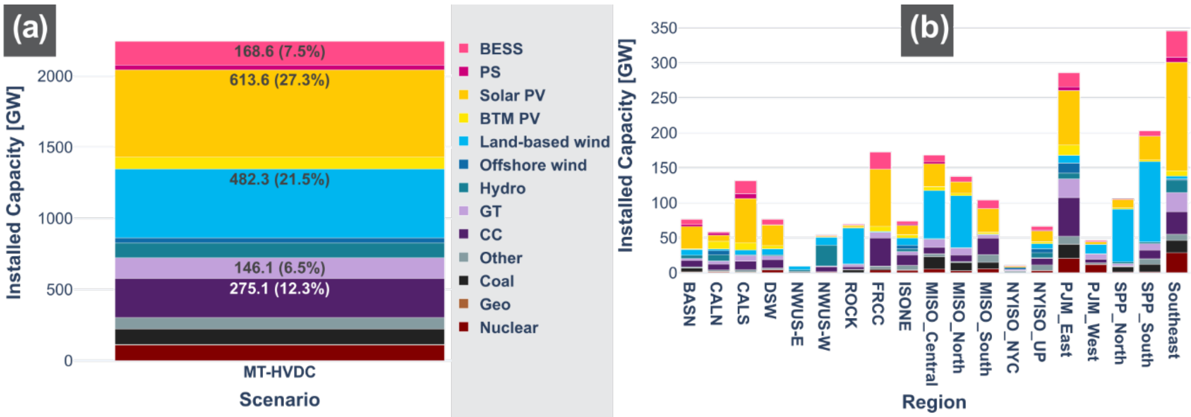


Figure B-8. Nodal disaggregated installed capacity for Western Interconnection and Eastern Interconnection

Total installed capacity is shown in (a); (b) shows installed capacity by subregion.

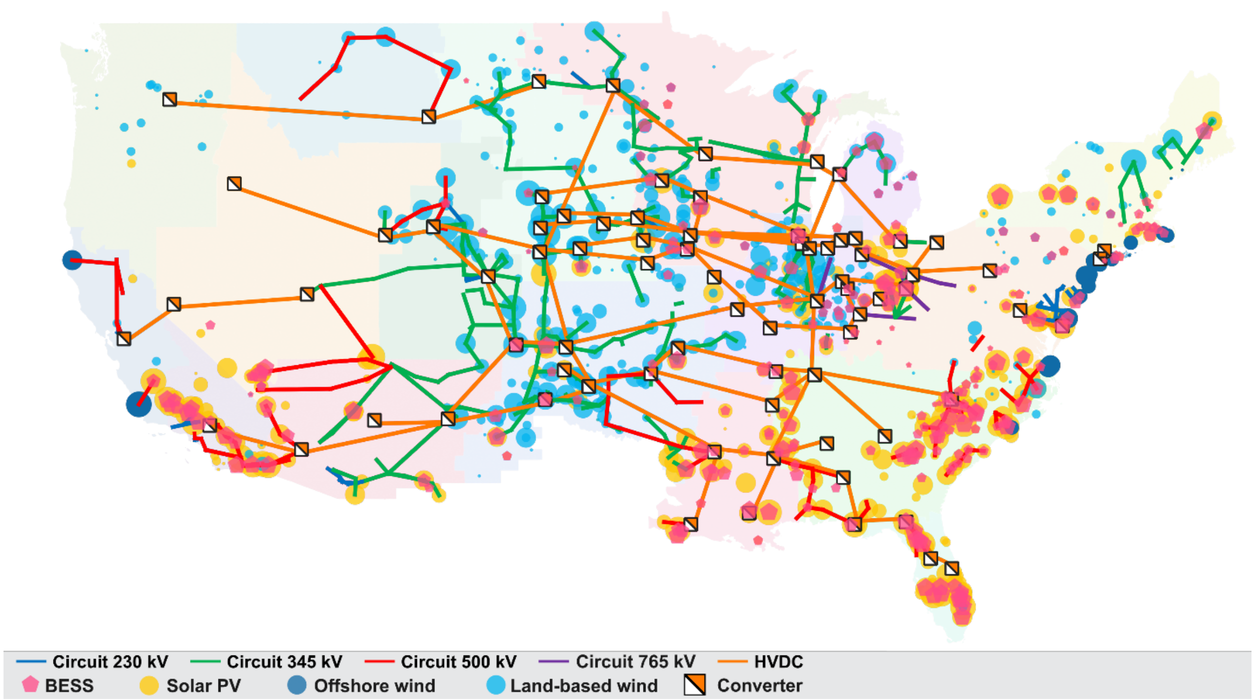


Figure B-9. Transmission expansion for MT-HVDC scenario for Western and Eastern Interconnection

The generation dispatch for the complete MT-HVDC scenario is shown in Figure B-10 aggregated over the combined Western and Eastern Interconnection footprint for the whole year and quarterly as well as split up by subregion. Except for the central section of MISO, the regional breakdown highlights wind generation is using the MT-HVDC network to get to load. The central section of MISO lies in the path of many HVDC connections to the hub around Chicago, Illinois. Some of the converter stations around this hub are placed in the MISO footprint and the power continues to Chicago on the AC system. This helps explain the opposite direction of DC and AC imports in the bottom of Figure B-10 for MISO Central.

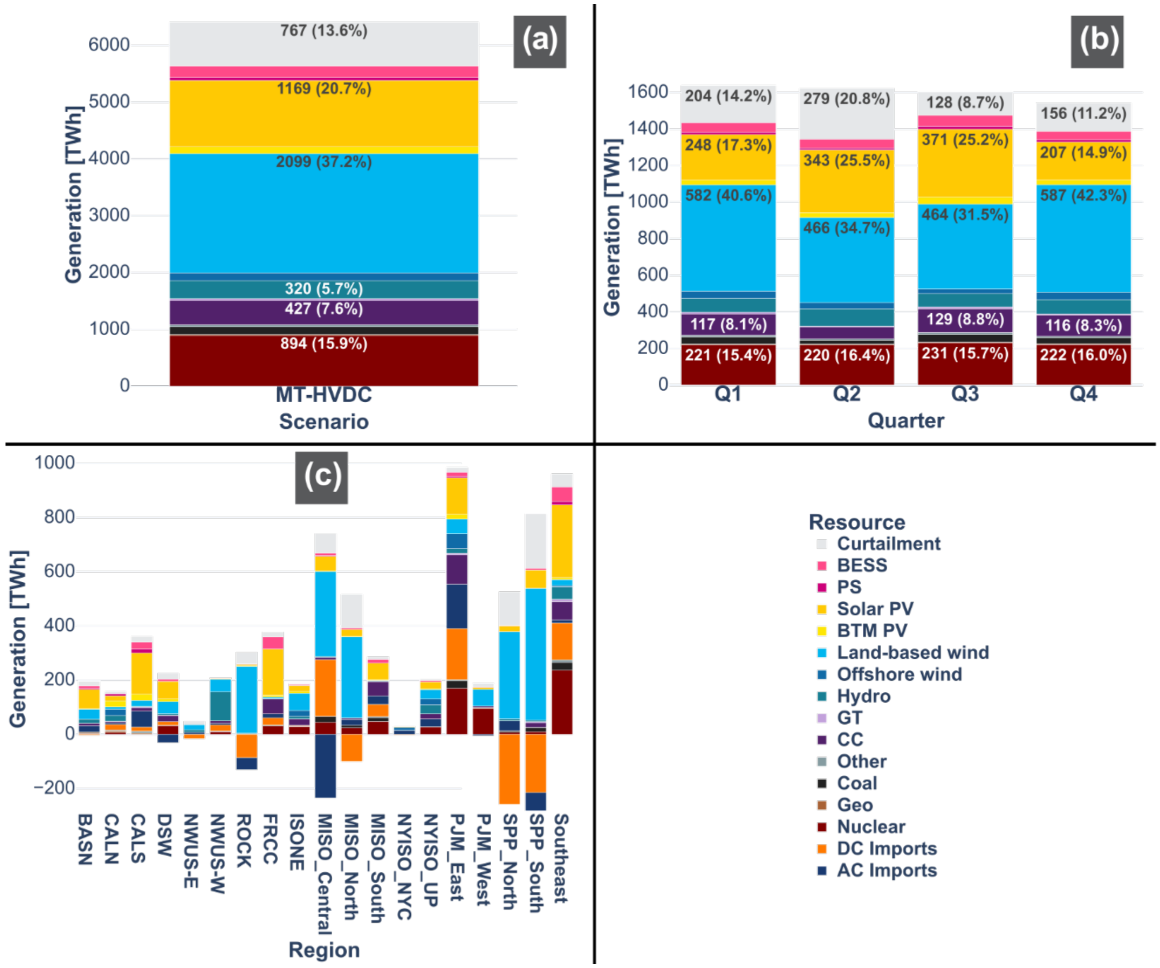


Figure B-10. Generation dispatch for combined Western Interconnection and Eastern Interconnection

Panel (a) shows totals, (b) shows by quarter, and (c) shows by region.

Curtailment in the complete MT-HVDC scenario is shown in Figure B-11. The distribution in terms of resource type skews much more heavily toward wind compared to the Western Interconnection alone and is concentrated in the central regions of the country (SPP and MISO).

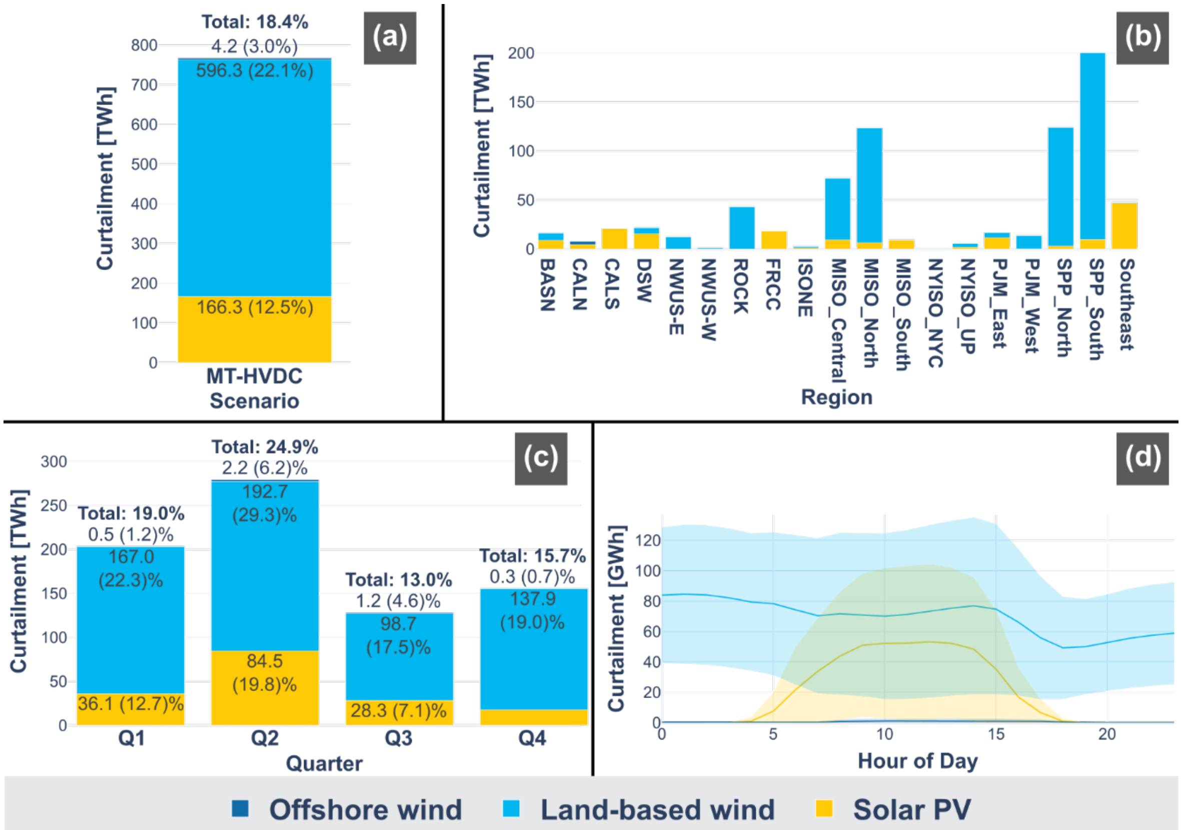


Figure B-11. Curtailment for combined Western Interconnection and Eastern Interconnection footprint

Panel (a) shows aggregate curtailment, (b) shows aggregate curtailment by subregion, (c) shows aggregate curtailment by quarter, and (d) shows average weekday trends as lines with ±1 standard deviation shaded.

The use of all HVDC corridors in both the Western Interconnection and Eastern Interconnection are shown along with their geographic location in Figure B-12 and Figure B-13. Except for the SPP north-south link and the FRCC to Southeast link, the flows in the east are predominantly one-sided, showing a movement from the resource-rich western portion to the load areas in the east. This pattern contrasts with the use of HVDC in the Western Interconnection, where flows—especially along the southern border—are more bidirectional.

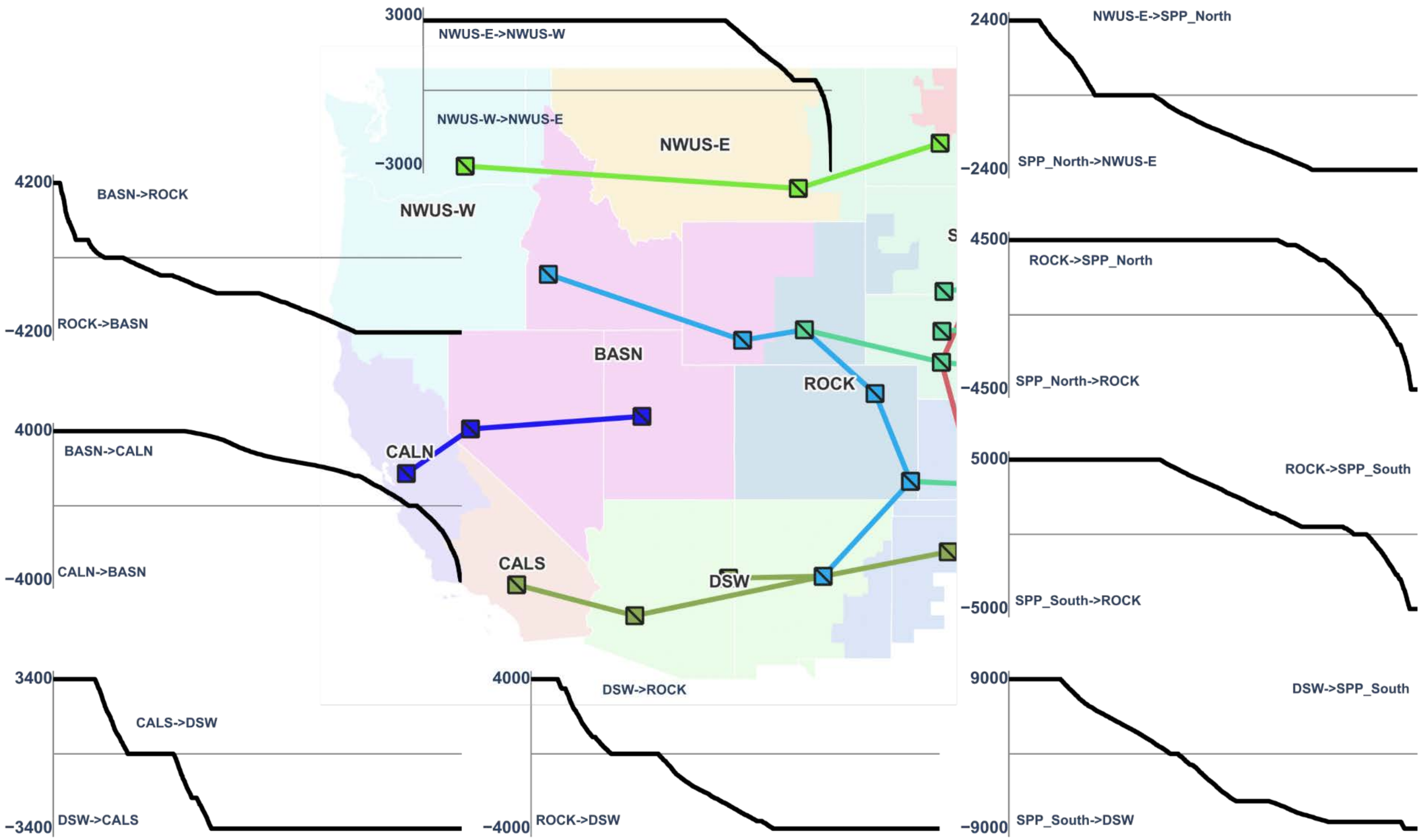


Figure B-12. Use of HVDC interregional interfaces in the MT-HVDC scenario (Western Interconnection)

Flow duration curves show the aggregate flow on the MT-HVDC lines between the subregions (including seam flows to the Eastern Interconnection).

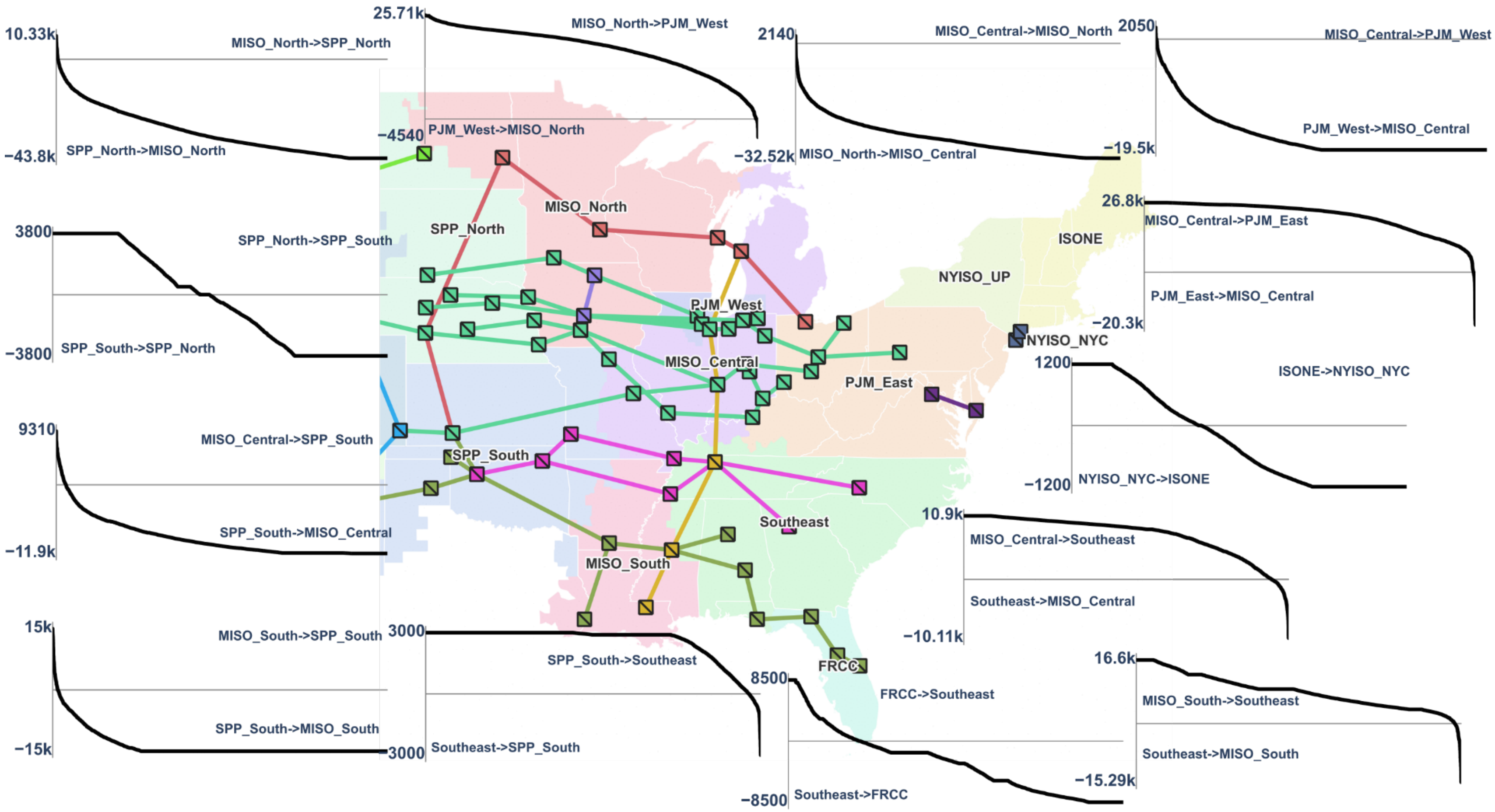


Figure B-13. Use of HVDC interregional interfaces in the MT-HVDC scenario (Eastern Interconnection)

Flow duration curves show the aggregate flow on the MT-HVDC lines between the subregions. Note the HVDC links in PJM do not cross subregion boundaries and are therefore not shown.

Appendix C. Tools

C.1 Sienna Modeling Framework

Production cost models simulate the least-cost optimal scheduling of electric generation to meet system demand and transmission constraints. The functionality provided by the Sienna modeling framework was used as the production-cost simulation engine in the National Transmission Planning Study (NTP Study) (National Renewable Energy Laboratory [NREL] 2024; Lara et al. 2021). The choice of the Sienna modeling framework was a result of the range of libraries that make up Sienna being capable of efficient and reproducible data management, programmatic access (which enables reproducibility and dataset maintenance), and efficient storage and access to support large-scale modeling, validation, and change management (all enabled through the libraries part of Sienna\Data). Nodal production cost modeling in Sienna (via Sienna\Ops) is transparent, programmatic, and scalable, which enables validation and verification as well as the potential to develop further modeling functionality extensions. Based in Julia (Bezanson et al. 2017), the Sienna framework enables speed of development and execution combined with a wide range of available libraries while leveraging the JuMP modeling language embedded in Julia for optimization (Lubin et al. 2023).

C.2 Grid Analysis and Visualization Interface

The Grid Analysis and Visualization Interface is a web application prototype for visualizing large nodal bulk grid power simulations and is available at http://github.com/NREL/GRAVI. It has been developed primarily as part of the NTP Study with three main objectives:

- Aid in the dissemination of detailed nodal-level modeling results to stakeholders
- Visualize and interpret large-scale and data-intensive modeling results of the contiguous U.S. bulk power system
- Aid in the transmission expansion planning that forms part of the translation of zonal models into nodal models.

The tool provides a dynamic geospatial animated visualization of each timestep from a simulation run along with complementary dynamic subplots. A screenshot of this for a contiguous United States (CONUS)-wide nodal production cost model outcome is shown in Figure C-1. It provides two controllable geospatial layers: one for bulk power generation and the other for transmission use and flow.

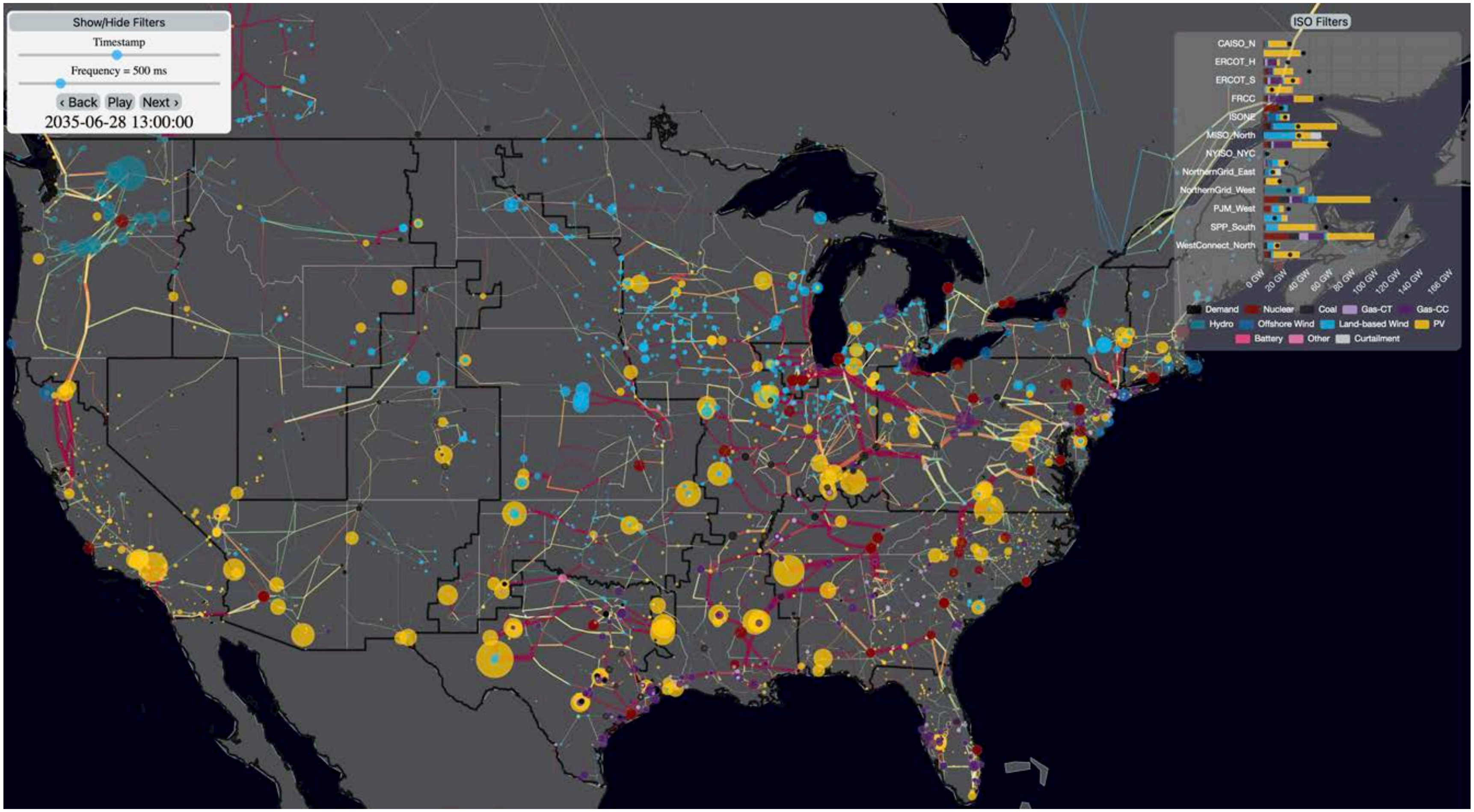


Figure C-1. Screenshot-generated custom tool developed for the NTP Study (Grid Analysis and Visualization Interface)

Appendix D. Economic Methodology

D.1 Transmission Capital Cost Methodology

Transmission costs for the Limited Alternating Current (AC) Western Interconnection case and the Interregional AC Western Interconnection case were developed based on the transmission lines added to the GridView Production Cost Model by voltage class (230 kilovolt [kV], 345 kV, and 500 kV). The Western Electricity Coordinating Council (WECC) Transmission Calculator (Black & Veatch 2019) updated by E3 in 2019 (E3 2019) was the basis for calculating the capital costs for transmission. The WECC Calculator multipliers for land ownership and terrain were used to estimate the cost of added transmission. The WECC Environmental Viewer was used to calculate costs for rights of way (ROWs), terrain, and land class. This appendix provides details on how the ROW costs and terrain type multipliers were used to estimate the transmission capital cost.

D.2 Developing the Right-of-Way Costs

Geospatial data for landcover, risk class, and Bureau of Land Management (BLM) zone designation were acquired from the WECC Environmental Viewer (ICF, n.d.) (see Figure D-1). The percent and total mileage of all transmission lines for each case intersecting land cover types and BLM category were estimated using the ArcMap Pro Tabulate Intersection Tool[68] (see Figure D-2 and Figure D-3). BLM land zones and their costs are provided in Figure D-1. Land cover cost is estimated by the total mileage multiplied by ROW width multiplied by BLM rental cost per acre (Table D-1). The ROW width required by transmission lines by voltage class was acquired from Duke Energy Transmission Guidelines (Table D-2) (Duke Energy, n.d.).

[68] ArcGIS Pro. No date. “Tabulate Intersection Analysis.” Available at https://pro.arcgis.com/en/pro-app/latest/tool-reference/analysis/tabulate-intersection.htm

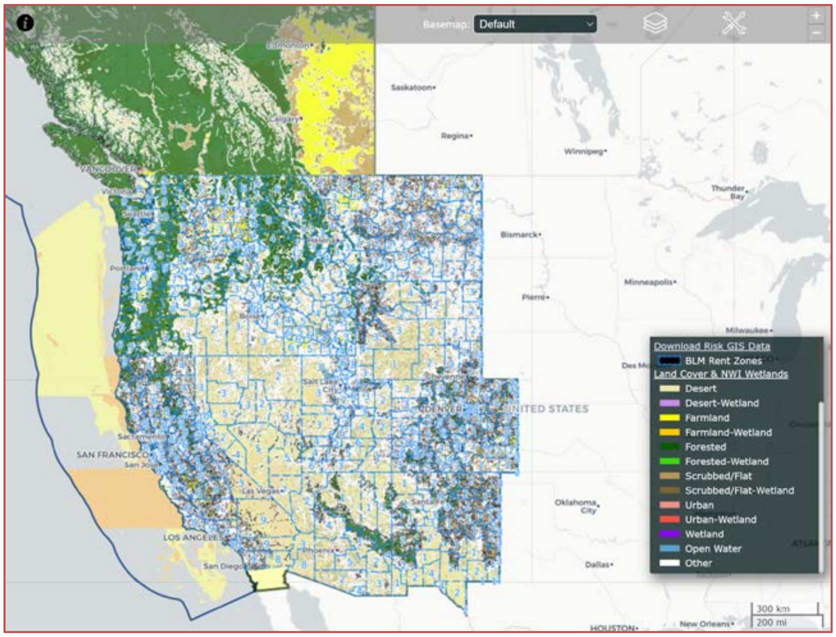


Figure D-1. WECC environmental data viewer

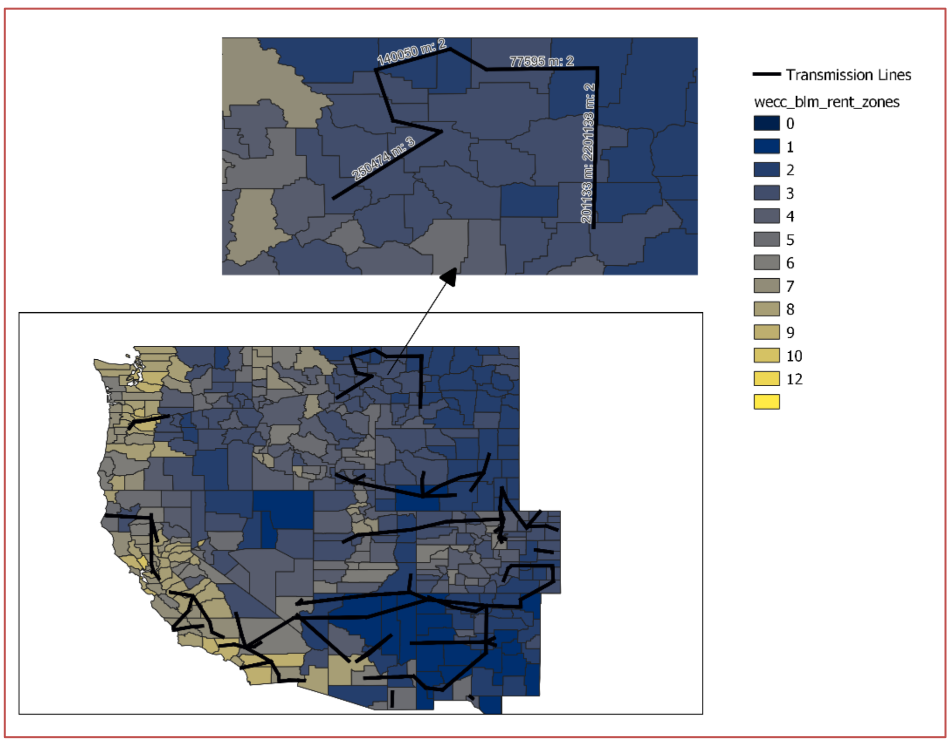


Figure D-2. BLM zone classes and transmission lines for Interregional AC Western Interconnection case

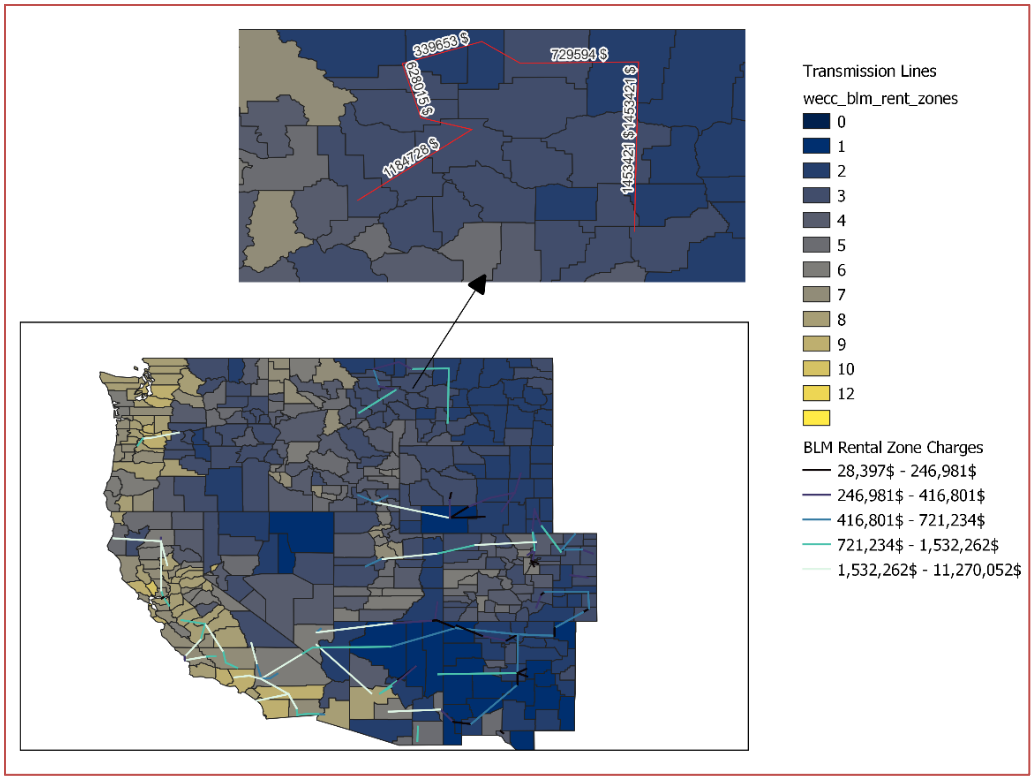


Figure D-3. Costs associated with respective BLM zone

Table D-1. BLM Cost per Acre by Zone Number

BLM Cost Zone Number	$/Acre
1	$83
2	$161
3	$314
4	$474
5	$653
6	$942
7	$1,318
8	$838
9	$4,520
10	$13,882
11	$27,765
12	$69,412
13	$138,824
14	$208,235
15	$277,647

Table D-2. Required Width for Transmission Lines by Voltage Class

Voltage Class (kV)	Min Required Width (ft)	Max Required Width
44–115	68	100
230	125	150
500–525	180	200

D.3 Estimating the Cost by Terrain Type

Cost by land cover and terrain type was estimated as a multiplier (Table D-3) times the cost per mile by voltage class (Table D-4). Voltage classes included single-circuit and double-circuit additions. The cost by mile assumes the conductor type is aluminum conductor steel reinforced (ACSR).

Table D-3. Land Cover and Terrain Classification Categories With Multiplier

Terrain Type	Terrain Type Identifier	Multiplier
Forested	1	2.25
Scrubbed/Flat	2	1
Wetland	3	1.2
Farmland	4	1
Desert/Barren Land	5	1.05
Urban	6	1.59
Rolling Hills (2%–8% slope)	7	1.4
Mountain (>8% slope)	8	1.75

Table D-4. Cost per Mile by Voltage Class

Voltage Class	Cost per Mile
230-kV Single Circuit	$1,024,335
230-kV Double Circuit	$1,639,820
345-kV Single Circuit	$1,434,290
345-kV Double Circuit	$2,295,085
500-kV Single Circuit	$2,048,670
500-kV Double Circuit	$3,278,535

D.4 Summary of Selected Literature Estimating the Economic Benefits of Transmission

Building interregional transmission in the United States requires cooperation across multiple balancing authorities and independent system operators (ISOs). Estimating the economic benefits of interregional transmission provides critical information that could help enable this cooperation. This section describes some of the issues highlighted in previous literature regarding estimation of the economic benefits of transmission.

Transmission investment has generally been lower than the socially optimum amount. William Hogan (1992), J. Bushnell and Stoft (1996), and J. B. Bushnell and Stoft (1997) have shown transmission investments that are profitable to private ownership are also economically efficient from a system perspective. However, many investments that are socially beneficial are not profitable for privately owned transmission (Doorman and Frøystad 2013; Egerer, Kunz and von Hirschhausen, Christian 2012; Gerbaulet and Weber 2018). The primary reason is transmission enables lower-cost generation, providing benefits to the system (and end consumers) that transmission owners do not receive and hence is not used in their decision making. Several studies have shown bargaining among utilities, ISOs, and so on will often not lead to an economically efficient amount of transmission and these issues are amplified when market distortions such as market power and higher negotiation costs are present (Cramton 1991; Anderlini and Felli 2006; Joskow and Tirole 2005).

William Hogan (2018) has written the most detailed methodology for the estimation and computation of transmission projects. His methodology draws on the vast literature on the economics of trade. A transmission can be modeled similar to a policy change that opens up trade between two nations/states/and so on that was previously closed. Trade economics is often taught from the perspective of comparative advantage, where both nations specialize in some product and specialization occurs with trade—benefiting both nations. With transmission, there is only one good available for trade. The region with lower-cost generation will be an exporter, and the region with higher-cost generation will be the importer. This can be modeled with the standard economic framework where generators are suppliers, utilities are the consumers, and the payments made for transmission are modeled similar to ad valorem taxes. Using this framework, producer benefits can be measured with producer surplus, consumer benefits can be measured with consumer surplus, and the payments to transmission owners are considered "transmission rents." Transmission rents are considered similar to ad valorem taxes where the revenue is a transfer to another entity—that is, transmission rents should not be considered losses, but the "wedge" the rents place between supply and demand does create deadweight loss.

Several studies have considered similar transmission expansion needs in the European Union (Sanchis et al. 2015; Neuhoff, Boyd, and Glachant 2012; Kristiansen et al. 2018). Olmos, Rivier, and Perez-Arriaga (2018) showed a potential North Sea transmission project joining six northern European countries could have net benefits up to €25.3 billion.

Within the United States, there have been limited national studies (Pfeifenberger, n.d.; Stenclik, Derek and Deyoe, Ryan 2022). Some studies estimate the benefits of intraregional transmission including in Midcontinent System Operator (MISO), California Independent System Operator (CAISO), and New York Independent System Operator (NYISO) (Gramlich, Rob 2022; Chowdhury and Le 2009; Conlon, Waite, and Modi 2019). These studies focus on estimating the benefits at the system level; i.e., they do not consider the benefits that accrue to consumers, producers, or transmission owners separately. The system benefits are computed by taking the reduction in generation costs within each region and adjusting by subtracting import payments and adding export revenues. William Hogan (2018) and CAISO (2017) showed the "system" method yields the same total regional benefit when the benefits to consumers, producers, and transmission rents are combined. However, the methods are equivalent only under the assumption demand is fixed at each location.

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