BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-26-46
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	)))))	Order No. 202-26-47

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 61
MISO Tariff Attachment Y

ATTACHMENT Y

Notification of Generation Resource/SCU/Pseudo-tied Out Generator

Change of Status,

Including Notification of Rescission

This is a notification of change of status of a Generation Resource, Synchronous Condenser Unit ("SCU"), or Pseudo-tied out Generator in accordance with Section 38.2.7.a of the Tariff. An electronic form must be submitted to the Transmission Provider via its online application tool in the manner specified by the Transmission Planning Business Practices Manual (BPM-020), and a form will be considered complete on the date of such online application.

The Transmission Provider may request additional information as reasonably necessary to support operations under the Tariff.

Owner of the Generation Resource, SCU or Pseudo-tied out Generator:

_____

Name of Market Participant:_____

Owner's state of organization or incorporation _____

Generation Resource/SCU/Pseudo-tied Out Generator [plant and unit number(s)] _____

_____

Source/Identification of Generation Interconnection Service [name of agreement, parties, date, date filed and docket number, and any other information to identify an agreement] _____

_____

Pursuant to the terms of the MISO Tariff, Owner hereby certifies that it will

[ ] Suspend for economic reasons operation of all or a portion of the Generation Resource/SCU/Pseudo-tied out Generator commencing on ___ [day] of _____ [month] of _____ [year]

[ ] Rescind the current notice to Suspend

The facility is further described as follows:

Location: _____

Unit Name	CPNode (if applicable)	Nameplate Capacity(MW)	Change in Capacity(MW)
_____	_____	_____	_____
_____	_____	_____	_____
_____	_____	_____	_____
_____	_____	_____	_____

Owner understands and agrees that this notification is provided in accordance with Section 38.2.7 of the Transmission Provider's Tariff and will not be made public by the Transmission Provider except as provided for under Section 38.2.7 of the Tariff.

The undersigned certifies that he or she is an officer of the owner of the Generation Resource/SCU/Pseudo-tied out Generator, that he or she is authorized to execute and submit this notification, and that the statements contained herein are true and correct.

_____

Signature

Name: _____ Contact Information

Title: _____ Email: _____

Date: _____ Phone: _____

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-26-46
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	)))))	Order No. 202-26-47

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 62
FERC Technical Conference Notice

Document Accession #: 20250602-3068 Filed Date: 06/02/2025

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Meeting the Challenge of Resource Adequacy in Regional Transmission Organization and Independent System Operator Regions	Docket No. AD25-7-000

THIRD SUPPLEMENTAL NOTICE OF COMMISSIONER-LED TECHNICAL CONFERENCE

(June 2, 2025)

As announced in the February 20, 2025 Notice in this proceeding, the Federal Energy Regulatory Commission (Commission) will convene a Commissioner-led technical conference in the above-referenced proceeding. The two-day technical conference will take place from 9:00 a.m. to 4:00 p.m. Eastern Time on Wednesday, June 4, 2025, and 9:00 a.m. to 4:15 p.m. Eastern Time on Thursday, June 5, 2025, in the Kevin J. McIntyre Commission Meeting Room at the Federal Energy Regulatory Commission, 888 First Street, NE, Washington, DC 20426.

The purpose of this technical conference is to discuss generic issues related to resource adequacy constructs, including the roles of capacity markets in the Regional Transmission Organization (RTO)/Independent System Operator (ISO) regions that utilize them and alternative constructs in RTO/ISO regions without capacity markets. The conference will start with a panel discussion on resource adequacy challenges across RTO/ISO regions, including regional differences. The remainder of the first day will include three panels specific to PJM Interconnection, L.L.C. (PJM) that will explore PJM's resource adequacy challenge, PJM states' perspectives, and additional perspectives on PJM's path forward. The second day will start with two panels specific to Midcontinent Independent System Operator, Inc. (MISO) that will explore MISO's resource adequacy challenge and perspectives on MISO's path forward. The remainder of the second day will include one panel to explore the resource adequacy challenge in ISO New England Inc. (ISO-NE) and New York Independent System Operator, Inc. (NYISO) and a final panel on the resource adequacy challenge in California Independent System Operator Corporation (CAISO) and Southwest Power Pool (SPP). The preliminary agenda for this conference is attached to this Supplemental Notice and provides more detail for each panel.

Commission staff will post pre-filed statements submitted by panelists on the FERC technical conference webpage prior to the conference and in eLibrary. With the exception of opening statements on Panel 1, which may be delivered orally, all other

panels will proceed immediately to questions from the Chairman and Commissioners.

All interested persons are also invited to file pre-technical conference comments in eLibrary on the issues of the conference, including the questions listed in the attached agenda. Commenters need not answer all the questions but are encouraged to organize responses using the numbering and sequencing in the attached agenda.

The Commission does not intend to discuss at this technical conference any specific proceeding pending before the Commission, including proceedings that involve similar issues. These proceedings include, but are not limited to:

NRG Business Marketing LLC; NRG Power Marketing LLC	Docket Nos.	ER23-2688, et al.; ER22-1539, et al.
Southwest Power Pool, Inc.	Docket Nos.	ER24-1317-000 ER24-2953-000
H.A. Wagner LLC; Brandon Shores LLC	Docket Nos.	ER24-1787, et al.; ER24-1790, et al.
PJM Interconnection, L.L.C.	Docket No.	ER24-2045-000
California Independent System Operator Corp.	Docket Nos.	ER24-2671, et al.
Southwest Power Pool, Inc.	Docket No.	ER25-89-000
Midcontinent Independent System Operator, Inc.	Docket Nos.	ER25-507, et al.
Manitowoc Public Utilities	Docket No.	ER25-634-000
PJM Interconnection, L.L.C.	Docket Nos.	ER25-682, et al.
PJM Interconnection, L.L.C.	Docket Nos.	ER25-712, et al.
PJM Interconnection, L.L.C.	Docket Nos.	ER25-785, et al.
PJM Interconnection, L.L.C.	Docket Nos.	ER25-1128, et al.
PJM Interconnection, L.L.C.; Commonwealth of Pennsylvania v. PJM Interconnection, L.L.C.	Docket Nos.	ER25-1357, et al.; EL25-46, et al.
PJM Interconnection, L.L.C.	Docket No.	ER25-1525-000

PJM Interconnection, L.L.C.	Docket No. ER25-1623-000
Midcontinent Independent System Operator, Inc.	Docket No. ER25-1674-000
Midcontinent Independent System Operator, Inc.	Docket No. ER25-1729-000
Midcontinent Independent System Operator, Inc.	Docket No. ER25-1802-000
Midcontinent Independent System Operator, Inc.	Docket No. ER25-1886-000
PJM Interconnection, L.L.C.	Docket No. ER25-2002-000
Midcontinent Independent System Operator, Inc.	Docket No. ER25-2050-000
New York Independent System Operator, Inc.	Docket No. ER25-2245-000
Midcontinent Independent System Operator, Inc.	Docket No. ER25-2247-000
Southwest Power Pool, Inc.	Docket No. ER25-2296-000
Southwest Power Pool, Inc.	Docket No. ER25-2297-000
Midcontinent Independent System Operator, Inc.	Docket No. ER25-2298-000
Sierra Club, Natural Resources Defense Council, Inc., and Sustainable FERC Project v. Southwest Power Pool, Inc.	Docket No. EL24-96-000
Sierra Club, Natural Resources Defense Council, Public Citizen, Sustainable FERC Project, and Union of Concerned Scientists v. PJM Interconnection, L.L.C.	Docket No. EL24-148-000
Joint Consumer Advocates, Illinois Citizens Utility Board, Maryland Office of the People's Counsel, New Jersey Division of Rate Counsel, Office of the Ohio Consumers' Counsel, Office of the People's Counsel for the District of Columbia v. PJM Interconnection, L.L.C.	Docket No. EL25-18-000

Constellation Energy Generation, LLC v. PJM Interconnection, L.L.C.	Docket No. EL25-20-000
PJM Interconnection, L.L.C., Allegheny Electric Cooperative, Inc., American Transmission Systems, Incorporated, Atlantic City Electric Company, Baltimore Gas and Electric Company, Delmarva Power & Light Company, Duke Energy Ohio, Inc., Duke Energy Kentucky, Inc., East Kentucky Power Cooperative, Inc., Essential Power Rock Springs, LLC, Hudson Transmission Partners, LLC, Jersey Central Power & Light Company, Mid-Atlantic Interstate Transmission, LLC, Neptune Regional Transmission System, LLC, Old Dominion Electric Cooperative, PECO Energy Company, PPL Electric Utilities Corporation, Potomac Electric Power Company, Public Service Electric and Gas Company, Rockland Electric Company, Trans-Allegheny Interstate Line Company, Transource West Virginia, LLC, UGI Utilities, Inc., Monongahela Power Company, The Potomac Edison Company, Commonwealth Edison Company, Commonwealth Edison Company of Indiana, Inc., The Dayton Power and Light Company, AEP Appalachian Transmission Company, Inc., AEP Indiana Michigan Transmission Company, Inc., AEP Kentucky Transmission Company, Inc., AEP Ohio Transmission Company, Inc., AEP West Virginia Transmission Company, Inc. Appalachian Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company, Wheeling Power Company, Duquesne Light Company, Virginia Electric and Power Company, Linden VFT, LLC,	Docket Nos. EL25-49, et al.

City of Cleveland, Department of Public Utilities, Division of Cleveland Public Power, City of Hamilton, OH, Southern Maryland Electric Cooperative, Inc., Ohio Valley Electric Corporation, AMP Transmission, LLC, Silver Run Electric, LLC, NextEra Energy Transmission MidAtlantic Indiana, Inc., Wabash Valley Power Association, Inc., Keystone Appalachian Transmission Company	
Joint Consumer Advocates v. PJM Interconnection, L.L.C.	Docket No. EL25-76-000
North American Electric Reliability Corporation	Docket No. RD25-7-000

The technical conference will be open to the public. Advance registration is not required, and there is no fee for attendance. Information will also be posted on the Calendar of Events on the Commission's website, www.ferc.gov, prior to the event. To stay apprised of issuances in this docket, there is an "eSubscription" link on the Commission's web site that enables subscribers to receive email notification when a document is added to a subscribed docket(s).

The technical conference will be transcribed and webcast. Transcripts will be available for a fee from Ace Reporting (202-347-3700). A link to the webcast of this event will be available in the Commission Calendar of Events at www.ferc.gov. The Commission provides technical support for the free webcasts. Please call 202-502-8680 or email customer@ferc.gov if you have any questions.

Commission technical conferences are accessible under section 508 of the Rehabilitation Act of 1973. For accessibility accommodations, please send an email to accessibility@ferc.gov or call toll free 1-866-208-3372 (voice) or 202-208-8659 (TTY) or send a fax to 202-208-2106 with the required accommodations.

For more information about this technical conference, please contact Tim Bialecki at timothy.bialecki@ferc.gov or 202-502-8403. For legal information, please contact Nathan Lobel at nathan.lobel@ferc.gov or 202-502-8456. For logistics information, please contact the Office of Public Participation (OPP) at OPP@ferc.gov or 202-502-6595.

Debbie-Anne A. Reese,
Secretary.

Meeting the Challenge of Resource Adequacy in Regional Transmission Organization and Independent System Operator Regions, Docket No. AD25-7-000

Agenda

Wednesday, June 4, 2025

9:00 am – 9:15 am: **Welcome and Opening Remarks**

9:15 am – 10:30 am: **Panel 1: The Resource Adequacy Challenge in RTOs/ISOs**

This panel will include opening statements from RTO/ISO representatives and a North American Electric Reliability Corporation (NERC) representative. Panelists should focus on defining resource adequacy, identifying resource adequacy challenges across RTOs/ISOs, and identifying information that will inform and guide later discussions.

In recent years, resource retirements, load growth, and the changing resource mix have contributed to resource adequacy challenges across the nation, including in the RTO/ISO regions. According to NERC's 2024 Long-Term Reliability Assessment, five of the six Commission jurisdictional RTO/ISO regions are at either high or elevated risk of experiencing electricity supply shortfalls.[1] High risk regions are expected to fall below established resource adequacy criteria in the next five years, while elevated risk regions meet resource adequacy criteria but are likely to experience shortfalls in extreme weather conditions. Some trends that continue to challenge regions' abilities to achieve resource adequacy include: increasing amounts of large commercial and industrial loads (e.g. data centers); electrification of energy end uses in transportation and building heating/cooling; retirement of baseload generation resources; and slower than anticipated interconnection of new resources.[2] RTO/ISO representatives should discuss their current resource adequacy constructs, recent resource adequacy challenges and, most importantly, their plans and recommendations to address resource adequacy challenges within their RTOs/ISOs in the future as demand grows.

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[1] NERC, *2024 Long-Term Reliability Assessment* 6 (Dec. 2024), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf.

[2] *See id.* 8-9, 12, 16, 19.

Questions that panelists could be asked:

1. What is the current state of resource adequacy across RTO/ISO regions? Is this static or variable? Are resource adequacy challenges more acute in RTO/ISO regions with capacity markets compared to those RTO/ISO regions with alternative resource adequacy constructs? Why or why not?

2. Given load growth and generation forecasts, what are your resource adequacy challenges going forward?

3. How do you reconcile your RTO's/ISO's resource adequacy objectives with state public policy requirements, which may accelerate the retirement of certain resource types or limit the entry of other resource types? For example, in light of such state public policy requirements and particularly in multi-state RTOs/ISOs, how does your RTO/ISO ensure resource adequacy?

4. What are the key drivers that cause delays in the construction and interconnection of generators in your RTO/ISO? What can be done to accelerate the interconnection of generators to help meet the resource adequacy challenge? How have factors external to your RTO/ISO, such as supply chains and siting/permitting, impacted generator interconnection timelines? What is the composition of resources in the queue? Will accelerating queue processes help address the challenge of resource adequacy? How many resources (by number and aggregate nameplate capacity) have received approval for interconnection but have not been constructed? How, if at all, are the expected resource adequacy contributions of a resource in the interconnection queue considered during the interconnection process?

5. Are there additional concerns that may affect resource adequacy in the near term (e.g., over the next five years) and in the longer term (e.g., ten years and beyond)?

6. In NERC's view, what aspects of resource adequacy planning could be improved? For example, what type of reliability metric (or metrics) should be used in resource adequacy planning models? What elements of resource adequacy planning can be improved or could serve as best practices?

7. How does your RTO/ISO approach capacity accreditation? What are the benefits and drawbacks of harmonizing capacity accreditation methods across regions versus allowing for regional variation?

    a. Given that many regions use the same probabilistic models for both evaluating resource adequacy and/or reserve margins and for Effective Load Carrying Capability (ELCC) accreditation, are there best practices in approaches that NERC is observing that could help align various regions

across the country in using the best modeling methodologies or data sources, etc.?

b. What are the potential strengths, weaknesses, and implementation considerations of alternatives to ELCC when evaluating the contribution of various types of resources in meeting resource adequacy requirements?

8. How can the RTOs/ISOs ensure that their demand forecasts adequately take into account load growth from data centers and other large loads? How can the RTOs/ISOs ensure there is sufficient supply to meet these demands, and what will those sources of supply be?

9. How can demand flexibility and demand-side management solutions be utilized to address load growth and resource adequacy concerns?

10. How do you reflect transmission availability—both regional and interregional—in your resource adequacy planning and requirements? To what extent do your transmission planning processes capture the resource adequacy benefits of regional and interregional transmission?

Panelists

- Manu Asthana, PJM, President and CEO
- Todd Ramey, MISO, Senior Vice President of Markets and Digital Strategy
- Gordon van Welie, ISO-NE, President and CEO
- Richard J. Dewey, NYISO, President and CEO
- Lanny Nickell, SPP, President and CEO
- Elliot Mainzer, CAISO, President and CEO
- Jim Robb, NERC, President and CEO

10:30 am – 10:45 am: 15-minute Break

10:45 am – 12:00 pm: Panel 2: PJM's Resource Adequacy Challenge

This panel discussion among the Commission, PJM, and stakeholders will focus on resource adequacy challenges specific to PJM, including whether changes to the existing market construct are needed or potential alternatives to the existing mandatory capacity market construct should be considered.

PJM states that it is facing potential capacity shortfalls as soon as the 2026/2027 Delivery Year due to a combination of trends, including growing electricity demand,

rapid retirement of thermal generators, and slow entry of replacement generation.[3] PJM's capacity auction for the 2025/2026 Delivery Year cleared at record high prices due to a variety of factors, including declines in supply, growing demand, a higher reserve requirement, and revised capacity market rules.[4] In response to recent challenges, PJM has revisited several of its capacity market's design elements, such as non-performance penalties, granular resource adequacy modeling, resource accreditation, and the role of reliability must-run resources in PJM's capacity market.[5]

Questions that panelists could be asked:

1. What is the state of resource adequacy in PJM in the near term (e.g., over the next five years) and over the longer term (e.g., ten years and beyond)?

2. Going forward, what steps will PJM need to take to ensure resource adequacy? Is PJM's resource adequacy construct adequate to determine resource adequacy needs given changing circumstances (e.g., unforeseen load growth, changes in state public policy requirements, faster-than-anticipated retirement of resources)?

3. How does PJM establish its load and resource forecasts?

    a. Have the assumptions driving load and capacity resource forecasts changed over time? If so, how?

    b. How do the forecast models weight different inputs? Are some assumptions more uncertain, important, or impactful than others?

    c. How have the forecasts performed historically and are you considering any changes to forecasting models or processes? For example, are you considering requiring demonstration of commercial readiness from prospective new large load additions?

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[3] PJM Board of Directors, Letter to Stakeholders (Dec. 9, 2024), https://www.pjm.com/-/media/DotCom/about-pjm/who-we-are/public-disclosures/2024/20241209-board-letter-outlining-action-on-capacity-market-adjustments-rri-and-sis.pdf.

[4] PJM, *2025/2026 Base Residual Auction Results* (2024), https://www.pjm.com/-/media/DotCom/committees-groups/committees/mrc/2024/20240821/20240821-item-08---2025-2026-base-residual-auction---presentation.pdf.

[5] *See PJM Interconnection, L.L.C.*, 190 FERC ¶ 61,088 (2025); *PJM Interconnection, L.L.C.*, 190 FERC ¶ 61,117 (2025).

4. To what extent are barriers to entry (e.g., the interconnection queue backlog, supply chain limitations, siting and permitting delays, etc.) impeding the ability of the capacity market to achieve resource adequacy at just and reasonable rates? What opportunities are there to address these barriers to entry?

5. How does PJM consider electric-gas coordination issues in the context of resource adequacy planning and capacity resource accreditation?

    a. To what extent do uncertainties pertaining to natural gas fuel supplies or infrastructure constraints affect resource adequacy planning in PJM? How can PJM better address those uncertainties?

    b. Does PJM need additional natural gas pipeline infrastructure for the future or is existing infrastructure sufficient?

6. To what extent does the availability of regional and interregional transmission capability affect resource adequacy planning in PJM? How can PJM better address the effect of transmission capability on resource adequacy?

7. Is the PJM capacity market adequately designed to provide correct signals for needed capacity additions? Given the degree to which the capacity market rules have changed in recent years, is the PJM capacity market producing stable investment signals? How have these frequent rule changes affected market participants and consumers? How has PJM sought to maintain stable investment signals in the face of these changes?

8. Do you think PJM's capacity market is more effective at delivering resource adequacy than other RTOs/ISOs' approaches would be in PJM and, if so, why?

9. Are there alternatives to a mandatory capacity market construct that should be considered, such as a residual capacity market construct (e.g., MISO), enhanced use of self-supply mechanisms such as Fixed Resource Requirement (FRR), or other mechanisms, including allowing load-serving utilities to own generation, increased long-term contracting by load-serving utilities, or other alternatives? To what extent do the current PJM market rules allow for these alternatives?

10. Several states in PJM have public policy requirements that drive resource entry and exit decisions. How does PJM work with the states and the District of Columbia to identify and meet the region's resource adequacy needs at just and reasonable rates? Has PJM studied the effects of state public policy on either resource adequacy or capacity market outcomes? What are the effects of state policies on resource adequacy in PJM?

Panelists

- Adam Keech, PJM, Vice President of Market Design and Economics
- Joe Bowring, Monitoring Analytics, President and Independent Market Monitor
- Wendy Stark, PPL Corporation, Executive Vice President of Utilities & Chief Legal Officer
- Brian Tierney, FirstEnergy, Chairman, President, and CEO
- Glen Thomas, PJM Power Providers Group, President
- Marji Philips, LS Power, Senior Vice President of Wholesale Market Policy
- Scott Hallam, Boardwalk Pipelines, President and CEO (on behalf of the Interstate Natural Gas Association of America (INGAA)).

12:00 pm – 1:00 pm: Lunch Break

1:00 pm – 2:15 pm: Panel 3: PJM States' Perspectives

This panel discussion between the Commission and state representatives will focus on the status of resource adequacy, and the role of states in achieving resource adequacy, in PJM.

Questions that panelists could be asked:

1. What should be the allocation of roles and responsibilities between PJM and the states to ensure resource adequacy in the PJM region? Please explain the role your state takes on with regard to the procurement of capacity to meet resource adequacy requirements, including with respect to bilateral contracting, self-supply, and/or purchases from the PJM capacity market. Do states in PJM have appropriate opportunities to participate in PJM decisions regarding resource adequacy? Are there different, or greater, responsibilities that states should assume to ensure resource adequacy?

2. Is PJM's capacity market compatible with state public policy requirements? Why or why not?

3. Do you believe consumers are treated fairly in the PJM capacity market process? If so, why? If not, why not?

4. Are changes necessary to ensure that the PJM capacity market process delivers resource adequacy at just and reasonable rates?

5. What barriers, if any, are there to PJM states assuming more responsibility for resource adequacy via constructs like the Integrated Resource Planning (IRP) model, a hybrid between the capacity market and IRP model, or enhanced use of

self-supply mechanisms such as FRR? Should alternatives to the mandatory capacity market construct be considered or does your state prefer retaining the existing construct?

6. Does your state currently have sufficient expertise on resource adequacy mechanisms and resource adequacy modeling to meet the challenge of resource adequacy without PJM's technical expertise, or does your state need additional resources? If your state would need additional resources, what types of resources would be required and what are the benefits and costs of developing that technical expertise compared with continuing to rely on PJM's expertise? Based on those costs and benefits, would your state prefer to continue to rely on PJM's technical expertise?

7. What state mechanisms, such as long-term bilateral contracts, self-supply arrangements, or other approaches, exist to help ensure that rates for procuring resources will be just and reasonable? Will consumers have access to the information (transparency) to understand their share of the costs for procuring adequate resources?

Panelists

- Chairman Emile C. Thompson, Public Service Commission of the District of Columbia, President of Organization of PJM States, Inc. (OPSI)
- Jacob Finkel, Office of the Governor of Pennsylvania, Deputy Secretary of Policy
- President Christine Guhl-Sadovy, New Jersey Board of Public Utilities
- Commissioner Kelsey Bagot, Virginia State Corporation Commission
- Commissioner Michael Richard, Maryland Public Service Commission
- Commissioner David Veleta, Indiana Utility Regulatory Commission
- Commissioner Dennis Deters, Public Utilities Commission of Ohio

2:15 pm – 2:30 pm: 15-minute Break

2:30 pm – 3:45 pm: Panel 4: Additional Perspectives on PJM's Path Forward and the Future of Resource Adequacy in PJM

Panelists will offer their varied perspectives on the topics discussed in the first two PJM-specific panels. Topics to be explored during this panel may include reforms to the current PJM capacity market design, potential alternatives to the existing mandatory capacity market, the roles and interests of states and other entities (e.g., cooperative and municipal systems) in achieving resource adequacy, and how to ensure resource adequacy at reasonable costs for consumers.

Panelists

- Brian O. Lipman, Consumer Advocates of the PJM States (CAPS), President
- Brian George, Google, US Energy Markets, Senior Lead
- Casey Roberts, Natural Resources Defense Council, Director of RTO Advocacy
- Michelle Bloodworth, America's Power, President and CEO
- Denise Foster Cronin, East Kentucky Power Cooperative, Vice President of Federal and RTO Regulatory Affairs
- Susan E. Bruce, Industrial Energy Consumers of America, PJM Industrial Customer Coalition, Coalition of MISO Transmission Customers, and American Forest & Paper Association, Counsel

3:45 pm – 4:00 pm: June 4 Closing Remarks

Thursday, June 5, 2025

9:00 am – 9:15 am: Welcome and Opening Remarks

9:15 am – 10:45 am: Panel 5: MISO's Resource Adequacy Challenge

This panel discussion among the Commission, MISO, and MISO stakeholders will focus on resource adequacy challenges specific to MISO.

MISO faces the most immediate risk of falling below established resource adequacy criteria compared to all other regions assessed by NERC in its 2024 Long-Term Reliability Assessment.[6] According to MISO's 2024 Regional Resource Assessment (RRA), MISO may need to add 17 gigawatts of new capacity each year for the next 20 years—more than triple the recent average rate of 4.7 gigawatts per year—to reliably meet future demand and policy goals.[7] Although MISO's RRA expects thermal resources and battery storage to account for the bulk of the region's accredited capacity in the future, the capacity of variable energy resources is expected to grow and contribute to

[6] *See* NERC, *2024 Long-Term Reliability Assessment* (Dec. 2024), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf.

[7] MISO, *2024 Regional Resource Assessment* (Jan. 2025), https://wdeawebsite.blob.core.windows.net/usrfiles/documents/miso%202024%20regional%20resource%20assessment.pdf.

an increasing need for ramp capability.[8]

Questions that panelists could be asked:

1. What is the state of resource adequacy in MISO in the near term (e.g., over the next five years) and over the longer term (e.g., ten years and beyond)?

    a. Is MISO's resource adequacy construct delivering resource adequacy in MISO?

    b. What are the benefits and drawbacks to MISO's resource adequacy construct and residual capacity auction?

2. How have the recent outcomes of MISO's capacity auctions affected market participants and consumers in MISO? Do states and stakeholders have confidence that the MISO capacity market will be effective to achieve resource adequacy at just and reasonable rates?

3. How have the seasonal resource adequacy requirements and revised capacity accreditation methods worked in MISO to date? Have they helped MISO more accurately determine its resource adequacy needs? What issues or challenges has MISO experienced in implementing a seasonal construct and revising capacity accreditation, and how does MISO plan to address those issues or challenges?

4. How does MISO establish its load and resource forecasts?

    a. How does MISO integrate the load forecasts provided by load-serving entities and electric distribution companies into their planning reserve margin requirements? Does MISO verify the forecast methodologies and accuracy of forecasts?

    b. Have the assumptions driving load and resource forecasts changed over time? If so, how?

    c. How do the forecast models weight different inputs? Are some assumptions more uncertain, important, or impactful than others?

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[8] *Id.* at 6-9. The RRA is one of several periodic studies MISO conducts to forecast how the mix of electricity-generating resources in the MISO region could evolve going forward. In other studies, MISO has modeled potential future scenarios where thermal resources have a decreased role in providing accredited capacity. *See, e.g.*, MISO, *Futures Report Series 1A* 75, 92 (Nov. 2023), Series1A_Futures_Report630735.pdf.

d. How have the forecasts performed historically and are parties considering any changes to forecasting models or processes? For example, are you considering requiring demonstration of commercial readiness from prospective new large load additions?

5. To what extent are barriers to entry (e.g., the interconnection queue backlog, supply chain limitations, siting and permitting delays, etc.) affecting resource adequacy in the MISO footprint?

6. To what extent does the availability of regional and interregional transmission capability affect resource adequacy planning in MISO? How can MISO better address the effect of transmission capability on resource adequacy?

7. Would an alternative resource adequacy construct used by another RTO/ISO be more effective at delivering resource adequacy in MISO? If so, why? Are there alternatives to the current residual market construct that should be considered?

8. What should be the allocation of roles and responsibilities between MISO and the states to ensure resource adequacy in the MISO region? How does MISO work with the states to identify and meet the region's resource adequacy needs at just and reasonable rates? Has MISO studied the effects of state public policy on either resource adequacy or capacity market outcomes?

Panelists

- Todd Ramey, MISO, Senior Vice President of Markets and Digital Strategy
- David Patton, Potomac Economics, President and MISO Independent Market Monitor
- Laura Beauchamp, Entergy Louisiana, LLC, Vice President of Business Operations and Strategy
- Andrew Meyer, Ameren Missouri, Sr. Director of Energy Management & Trading
- Steven Lieberman, American Municipal Power Inc., Vice President of Transmission & Regulatory Affairs
- Todd Snitchler, Electric Power Supply Association, President and CEO
- Kelli Joseph, World Resources Institute, Senior Fellow

10:45 am – 11:00 am: 15-minute Break

11:00 am – 12:15 pm: Panel 6: MISO's Path Forward and The Future of Resource Adequacy in MISO

This panel discussion among the Commission, state representatives, and others will focus on the state of resource adequacy, and the role of states in achieving resource adequacy, in MISO. The Commission will explore approaches to address MISO's resource adequacy challenges, and the benefits of and improvements to its resource adequacy construct, to ensure MISO and states achieve resource adequacy.

Questions that panelists could be asked:

1. How do MISO and state resource adequacy processes interact? Do states in MISO have appropriate opportunities to participate in decisions regarding resource adequacy? Are there different or greater responsibilities that states should assume to ensure resource adequacy?

2. Do you believe consumers are treated fairly in the MISO capacity market process? If so, why? If not, why not?

3. Are changes necessary to ensure that the MISO capacity market process delivers resource adequacy at just and reasonable rates?

4. Are there aspects of MISO's resource adequacy construct that may result in inefficient price signals or create unnecessary resource adequacy risks?

5. Could MISO ensure resource adequacy at a lower cost to consumers through modifications to its existing resource adequacy construct? If so, what are the modifications and what are the challenges or downsides to implementing them?

6. Should MISO's capacity market model be replaced?

    a. If MISO's capacity market model should be replaced, what should replace it? Could an alternative resource adequacy program, like in SPP and CAISO, or a more expansive capacity market construct, like in PJM, NYISO, and ISO-NE, achieve resource adequacy at a lower cost than MISO's resource adequacy construct? Would these alternative approaches provide load-serving entities, states, and consumer advocates with the necessary information to monitor their costs for capacity?

    b. What are the potential tradeoffs and challenges of switching to a different resource adequacy construct? What timeline would be needed to determine or vet a replacement and implement it?

Panelists

- Commissioner Marcus Hawkins, Wisconsin Public Service Commission, Chair of the Organization of MISO States (OMS) Resource Adequacy Committee
- Chairman Doug Scott, Illinois Commerce Commission
- Chairman James Huston, Indiana Utility Regulatory Commission
- Commissioner Eric Skrmetta, Louisiana Public Service Commission
- Carrie Zalewski, American Clean Power Association, Vice President of Transmission and Electricity Markets
- Jennifer C. Easler, Iowa Department of Justice Office of Consumer Advocate, Attorney

12:15 pm – 1:15 pm: Lunch Break

1:15 pm – 2:30 pm: Panel 7: The Resource Adequacy Challenge in the Northeast RTOs/ISOs

This panel discussion between the Commission, NYISO, ISO-NE, and relevant stakeholders will focus on resource adequacy challenges specific to NYISO and ISO-NE.

NYISO projects declining statewide resource margins and for the system to approach a loss of load expectation of 1 day in 10 years by 2034.[9] NYISO's resource adequacy forecast is heavily affected by the assumption that approximately 6,400 MW of non-firm, gas-only generation will not be available to serve loads during winter peak demand periods.[10] NYISO explains that decreasing, and even negative, statewide system margins are a leading indicator of the system's inability to reliably serve demand under normal operations while fully maintaining operating reserves.[11] NYISO also notes that the development and commercialization of dispatchable emission-free resources capable of providing sustained on-demand power and system stability will be essential to achieving policy objectives while maintaining a reliable electric grid.[12]

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[9] NYISO, *2024 Reliability Needs Assessment* 9 (Nov. 19, 2024), nyiso.com/documents/20142/2248793/2024-RNA-Report.pdf/.

[10] *Id.*

[11] *Id.* at 10.

[12] NYISO, *NYISO's 2024 Comprehensive Area Review of Resource Adequacy* 37-38 (Dec. 3, 2024), https://cdn.prod.website-files.com/67229043316834b1a60feba3/678584c131bec5c726bae51b_2024%20New%20York%20Comprehensive%20Area%20Review%20of%20Resource%20Adequacy%20P

ISO-NE, in comparison, states that it has procured or will procure the requisite resources needed to adequately meet resource adequacy for each year of the 2024-2028 study horizon.[13] ISO-NE predicts growing peak load through 2032 and identifies potential risks to bulk power system reliability, but expects bulk power system reliability and economic performance to improve over the next decade because of planned transmission upgrades, an improved interconnection process, development of renewable resources with energy storage, imports from neighboring regions, fast-start and flexible ramping resources, and energy efficiency/conservation measures.[14]

Questions that panelists could be asked:

1. What is the state of resource adequacy in NYISO and ISO-NE in the near term (e.g., over the next five years) and over the longer term (e.g., ten years and beyond)?

    a. What factors present the greatest uncertainty when projecting future resource adequacy challenges?

    b. Are the capacity market constructs delivering resource adequacy in these RTOs/ISOs? Why or why not?

2. To what extent do uncertainties external to NYISO and ISO-NE—such as natural gas supplies or infrastructure constraints, supply chain limitations, and siting and permitting delays—affect resource adequacy planning in the Northeast? How can NYISO and ISO-NE better address those uncertainties?

3. How do NYISO and ISO-NE consider electric-gas coordination issues in the context of resource adequacy planning and capacity resource accreditation?

4. How will state public policy requirements change the resource mix and expected seasonal or hourly demand patterns? Do state public policy requirements create challenges for your regions in achieving resource adequacy at just and reasonable rates?

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[13] ISO-NE, *2023 New England Comprehensive Area Review of Resource Adequacy* 8-10 (Dec. 5, 2023), https://cdn.prod.website-files.com/67229043316834b1a60feba3/67229043316834b1a61003df_2023-new-england-comprehensive-review-of-resource-adequacy.pdf.

[14] *Id.* at 10.

5. How might your capacity markets be improved to meet the challenge of resource adequacy?

6. Would an alternative resource adequacy construct used by another RTO/ISO be more effective at delivering resource adequacy in your regions? If so, why?

7. How do NYISO and ISO-NE work with their states to identify and meet the region's resource adequacy needs and to ensure adequate resources are procured at just and reasonable rates? How do NYISO and ISO-NE work with their states when pursuing capacity market reforms to meet the resource adequacy challenge at the lowest possible cost to consumers? What distinct challenges must be overcome in a multi-state RTO/ISO (ISO-NE) region relative to a single state ISO region (NYISO)?

Panelists

- Emilie Nelson, NYISO, Executive Vice President and Chief Operating Officer
- Stephen George, ISO-NE, Vice President of System Operations and Market Administration
- Adam Evans, New York State Department of Public Service, Chief of Wholesale and Clean Energy Markets
- Chairman Philip L. Bartlett II, Maine Public Utilities Commission
- Commissioner Katie S. Dykes, Connecticut Department of Energy and Environmental Protection
- Michelle Gardner, NextEra Energy Resources, Executive Director Northeast Region
- Sarah Bresolin Silver, New England Power Pool, Chair
- Pallas LeeVanSchaick, Potomac Economics, Vice President; ISO-NE External Market Monitor; NYISO Market Monitoring Unit

2:30 pm – 2:45 pm: 15-minute Break

2:45 pm – 4:00 pm: Panel 8: RTOs/ISOs without Capacity Markets

This panel discussion between the Commission, SPP, CAISO, and relevant stakeholders will focus on resource adequacy programs in SPP and CAISO and how they compare to capacity markets in the other RTOs/ISOs.

In SPP, where each Load Responsible Entity must maintain adequate capacity to meet its Resource Adequacy Requirement, SPP expects no excess capacity to be available in summer 2027, and the planned reserve margin to decline from 20% in

summer 2024 to just 5% in summer 2029—a 5,950 MW deficiency.[15] Over that period, SPP projects resource retirements to outstrip new resource additions by a rate of roughly two-to-one while net peak demand grows by roughly 2% annually.[16] Most projected retirements are coal and natural gas resources.[17]

In California, the Public Utilities Commission (CPUC) oversees a resource adequacy construct to ensure jurisdictional load-serving entities meet those requirements. The CPUC sets system-wide resource adequacy requirements while CAISO sets local and flexible resource adequacy requirements. In recent years, CAISO and the CPUC have implemented regulatory and CAISO market changes to ensure that external capacity resources procured to meet resource adequacy requirements are delivered during peak net load hours.[18]

Questions that panelists could be asked:

1. What is the state of resource adequacy in SPP and CAISO in the near term (e.g., over the next five years) and over the longer term (e.g., ten years and beyond)? What factors present the greatest uncertainty when projecting future resource adequacy challenges?

2. Given load growth and generation entry and retirement forecasts, what resource adequacy challenges does SPP's resource adequacy construct face going forward? How does SPP's resource adequacy construct perform compared to RTO/ISO-administered capacity markets?

3. Given load growth and generation entry and retirement forecasts, what resource adequacy challenges does the CPUC's Resource Adequacy program face going forward? How does California's Resource Adequacy program perform compared to RTO/ISO-administered capacity markets?

4. How do the resource adequacy constructs employed by your RTO/ISO ensure the availability of resources for resource adequacy, and can they adapt to increased

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[15] SPP, *2024 SPP Resource Adequacy Report* 4-5 (June 14, 2024), 2024 spp june resource adequacy report.pdf.

[16] *Id.* at 6 & Table 1.

[17] *Id.*

[18] CAISO Department of Market Monitoring, *2023 Annual Report on Market Issues & Performance* 31-32 (July 29, 2024), 2023-annual-report-on-market-issues-and-performance.pdf.

load growth? How does this compare to attempting to meet these challenges through operation of an RTO/ISO-administered capacity market?

5. How do SPP and CAISO work with states to identify and meet the region's resource adequacy needs and to ensure adequate resources are procured at just and reasonable rates? How do SPP and CAISO work with their states when pursuing resource adequacy reforms to meet the resource adequacy challenge at the lowest possible cost to consumers? What distinct challenges must be overcome in a multi-state RTO/ISO (SPP) region relative to a single state ISO region (CAISO)?

Panelists

- Casey Cathey, SPP, Vice President of Engineering
- Neil Millar, CAISO, Vice President of Transmission Planning and Infrastructure Development
- Chair Patrick O'Connell, New Mexico Public Regulation Commission
- Molly Sterkel, California Public Utilities Commission, Director of Electric Supply, Planning and Costs in the Energy Division
- Stacey Burbure, American Electric Power, Senior Vice President of Transmission Business Development and Joint Ventures
- Gillian Clegg, Pacific Gas and Electric Company, Vice President of Energy Policy and Procurement
- Travis Kavulla, NRG, Vice President of Regulatory Affairs

4:00 pm – 4:15 pm: Closing Remarks

Document Content(s)

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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-26-46
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	)))))	Order No. 202-26-47

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 63
Palgrave Handbook



The Palgrave Handbook of International Energy Economics

Edited by Manfred Hafner · Giacomo Luciani

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rotating standby state through the advanced control system, and the gas turbine is quickly started with load, and the power is immediately transmitted to the power grid.

3.4 Location

Coal power generation location is more restrictive compared to other technologies because coal is a solid and its transport cost is high, while its combustion efficiency is lower than for other technologies. Usually coal plants are located near coal mines and the choice of different means of transport will affect the location of the plant area as well as the size and form of the required land plot, especially for a large power plant. The transportation mode should allow for large volume, low freight, high speed, and flexibility, which will make the location of coal plant all the more difficult.

On the contrary, oil is easy to transport with multiple transportation options including by pipeline and by ship; therefore, oil-fired plants are usually located in coastal areas. A gas-fired power plant is characterized by little land occupation and is very suitable for countries and areas with dense population and scarce land resources. Compared with coal-fired power plants, gas power generation equipment is more compact and does not occupy a large area. Besides, it consumes one-third of the water needed for a coal-fired power plant.

3.5 Expected Service Life

Thermal power plants are designed for an economic lifetime of 30 to 40 years, but some plants have been also used beyond their design life in certain areas. The critical components are the boiler and the turbine. The operation of thermal power generation is faced with both tangible and intangible aging processes. Tangible or physical aging refers to the equipment operating under high pressure and temperature, and bearing mechanical stress, resulting in physical and chemical changes, such as wear, creep, corrosion, and so on, gradually making the equipment unable to continue operating safely under the required design parameters. Invisible aging refers to technological progress. The advent of more efficient or less labor-intensive production equipment means that older equipment will operate under less and less economic conditions. The physical aging of some equipment (such as condenser copper pipes, heater pipes, boiler heating surface pipes, turbine blades, furnace walls, etc.) can be removed during overhaul. However, it is often the aging of these important equipment components that determines the technical and consequently economic lifetime of thermal power plants. Operating experience shows that the service life of equipment operating under 450 °C is between 40 and 50 years. For equipment operating at temperatures above 450 °C, the operating hours could even be reduced to 100,000 hours.

Both gas and steam turbines are devices that drive the rotor to rotate at high speed through high-pressure gas with high temperature and humidity.

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Exhibit 64
IEA Report



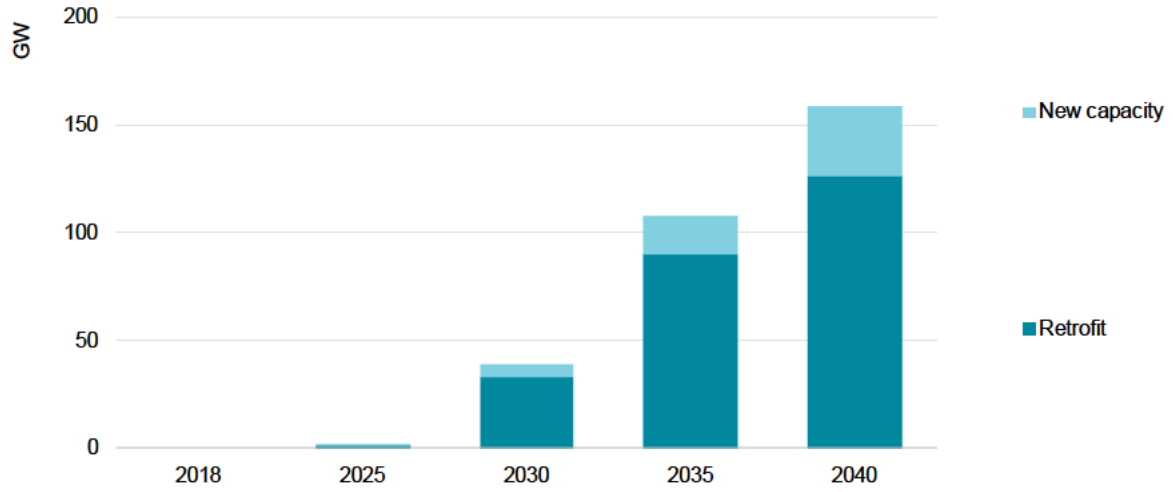
International Energy Agency

The role of CCUS in low-carbon power systems

Without carbon capture, meeting climate goals would ultimately mean almost eliminating the use of fossil fuels for power.

In the Sustainable Development Scenario, 120 GW of existing coal-fired capacity is retrofitted with carbon capture by 2040, accounting for some 80% of the coal plants equipped with these technologies. More than 110 GW of these retrofits are in China, representing a capital investment of around USD 160 billion. A further 10 GW are in the United States. Without carbon capture available at scale in power, coal-fired power generation, and eventually also gas-fired generation, would need to be virtually eliminated to meet long-term climate goals, with significant early retirements and potential stranding of assets.

Figure 4 Coal-fired power plants equipped with carbon capture in the Sustainable Development Scenario



Source: IEA (2019), World Energy Outlook 2019.

Over 750 GW of existing coal plants reduce operations to cut emissions in this Scenario, limiting electricity production but still providing system adequacy and flexibility. About one-quarter of the existing fleet would be retired before reaching the typical 50-year lifespan. Shutdowns and reduced operating hours are likely to lead to balance sheet write-downs for some owners of existing facilities. Coal plant retirements also imply greater investment in other low-carbon sources of electricity and associated network infrastructure.

Carbon capture retrofits also play an important role for the gas-fired power plant fleet, which currently has an average age of only around 19 years. In the SDS 155 GW of natural gas-fired power plants are equipped with carbon capture, utilisation and

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Exhibit 65
DOE Transmission Planning Study

National Transmission Planning Study



Chapter 2:

Long-Term U.S. Transmission Planning 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 (this chapter)** discusses the methods for capacity expansion and resource adequacy, key findings from the scenario analysis and economic analysis, and High Opportunity Transmission interface analysis.
- **Chapter 3: Transmission Portfolios and Operations for 2035 Scenarios** summarizes the methods for translating zonal scenarios to nodal-network-level models, network transmission plans for a subset of the scenarios, and key findings from transmission planning and production cost modeling for the contiguous United States.
- **Chapter 4: AC Power Flow Analysis for 2035 Scenarios** identifies the methods for translating from zonal and nodal production cost models to alternating current (AC) power flow models and describes contingency analysis for a subset of scenarios.
- **Chapter 5: Stress Analysis for 2035 Scenarios** outlines how the future transmission expansions perform under stress tests.
- **Chapter 6: Conclusions** describes the high-level findings and study limitations across the six chapters.

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

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

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

- **Barriers and Opportunities To Realize the System Value of Interregional Transmission** examines issues that prevent existing transmission facilities from delivering maximum potential value and offers a suite of options that power system stakeholders can pursue to overcome those challenges between nonmarket or a mix of market and nonmarket areas and between market areas.

- **Western Interconnection Baseline Study** uses production cost modeling to compare a 2030 industry planning case of the Western Interconnection to a high renewables case with additional planned future transmission projects based on best available data.

List of Acronyms

AC	alternating current
AEO	Annual Energy Outlook
APC	adjusted production cost
ATB	Annual Technology Baseline
B2B	back-to-back
BECCS	bioenergy with carbon capture and storage
CAISO	California Independent System Operator
CCS	carbon capture and storage
CO_2(e)	carbon dioxide equivalent
Coal-CCS	coal + carbon capture and storage
CSP	concentrating solar power
CT	combustion turbine
CTS	CO_2 transport and storage
DAC	direct air capture
DC	direct current
dGen	Distributed Generation Market Demand model
DOE	U.S. Department of Energy
EIA	Energy Information Administration
EPRI	Electric Power Research Institute
ERCOT	Electric Reliability Council of Texas
EUE	expected unserved energy
FERC	Federal Energy Regulatory Commission
FRCC	Florida Reliability Coordinating Council
GADS	Generating Availability Data System

GCM	global climate model
GET	grid-enhancing technologies
GHG	greenhouse gas
GW	gigawatt
H_2-CT	hydrogen combustion turbine
HOT	high opportunity transmission
HVDC	high-voltage direct current
IRA	Inflation Reduction Act
ISO	independent system operator
ISONE	ISO New England
kg	kilogram
km	kilometer
kV	kilovolt
kW	kilowatt
LBNL	Lawrence Berkeley National Laboratory
LCC	line-commutated converter
LCOE	levelized cost of energy
Lim	Limited (transmission framework)
LOLE	loss of load expectations
LOLP	loss of load probability
m	meter
MISO	Midcontinent Independent System Operator
MMT	million metric ton (CO_2)
MT	multiterminal
MW	megawatt

MWh	megawatt-hour
MW-mile	megawatt-mile
NARIS	North American Renewable Integration Study
NEMS	National Energy Modeling System
NERC	National Electric Reliability Corporation
NEUE	normalized expected unserved energy
NG-CC	natural gas combined cycle
NG-CT	natural gas combustion turbine
NPV	net present value
NREL	National Renewable Energy Laboratory
NTP Study	National Transmission Planning Study
SMR	small modular reactor
NYISO	New York Independent System Operator
P2P	point-to-point
POI	point of interconnection
ppm	parts per million
PRAS	Probabilistic Resource Adequacy Suite
PV	photovoltaic
RA	resource adequacy
ReEDS	Regional Energy Deployment System
RTO	regional transmission organization
reV	Renewable Energy Potential
RPS	renewable portfolio standard
SCRTP	South Carolina Regional Transmission Planning
SERTP	Southeastern Regional Transmission Planning

SMR	small modular reactor
SPP	Southwest Power Pool
Sup3rCC	Super-Resolution for Renewable Energy Resource Data with Climate Change Impacts
TES	thermal energy storage
TW	terawatt
TWh	terawatt-hour
TW-mile	terawatt-mile
VRE	variable renewable energy
VSC	voltage source converter
W	watt
WECC	Western Electricity Coordinating Council

Chapter 2 Overview

Accelerating transmission expansion can offer benefits for the contiguous U.S. electricity system under a wide range of future uncertainties. The potential role and impacts of transmission expansion are evaluated in this chapter of the National Transmission Planning Study (NTP Study). The chapter presents the methods, assumptions, and findings from the zonal analysis of long-term U.S. transmission planning scenarios. The analysis compares a "Limited" transmission framework, which constrains transmission expansion, against three accelerated transmission frameworks: Alternating Current (AC), Point-to-Point (P2P), and Multiterminal (MT) (Figure I). Because future transmission expansion can vary depending on external conditions, the analysis compared scenarios across all four transmission frameworks under a range of policy, demand growth, and other conditions. The analysis includes an assessment of 96 total scenarios.

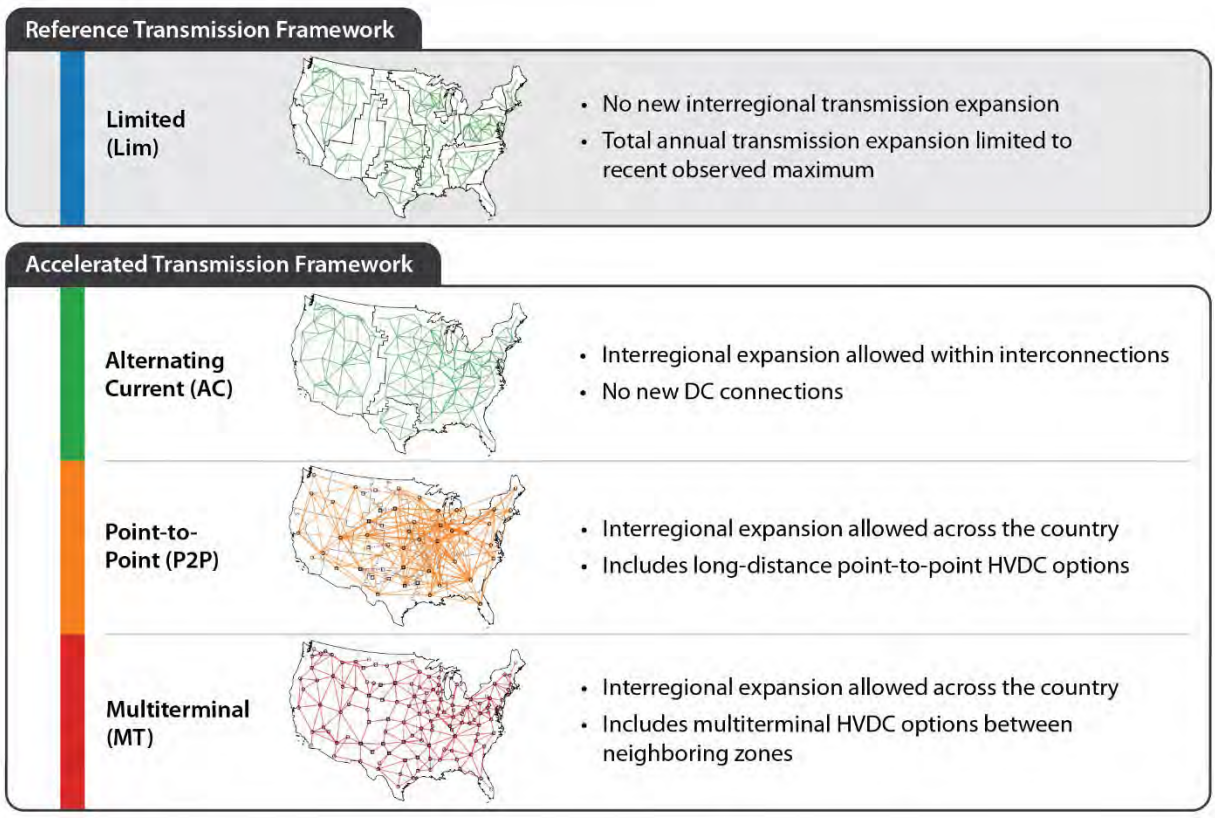


Figure I. NTP Study transmission frameworks

The scenario analysis first compares the different transmission frameworks without any new policies. Benefits from large-scale transmission expansion include billions of metric tons of avoided CO_2 emissions under current policies. Specifically, expanding transmission beyond historical rates—as occurs in the accelerated (AC, MT, P2P) frameworks—reduces power system CO_2 emissions by 10–11 billion metric tons (43%–48%) through 2050, relative to the Limited framework using "Mid" demand growth

assumptions (2.0%/year). The emissions reductions from accelerated transmission expansion are driven by increased wind and solar deployment. Even with expanded transmission, current policies are insufficient to fully eliminate power sector emissions, especially in futures with high demand growth.

The transmission frameworks were then evaluated considering nine decarbonization and demand futures (Figure II). Under these decarbonization conditions, benefits of large-scale transmission expansion include hundreds of billions of dollars in system cost savings. Specifically, in the central decarbonization scenarios—which achieve 90% emissions reductions by 2035 (100% by 2045) and assume Mid demand growth—accelerated transmission expansion leads to national electricity system cost savings through 2050 of $270–$490 billion. Constraining transmission growth results in more nuclear generation, hydrogen, and carbon capture capacity to achieve emissions reduction targets, leading to higher costs. The cost savings from accelerated transmission reveal that the costs of new transmission are outweighed by reductions in capital, operating, and fuel expenditures for generation and storage. Approximately $1.60 to $1.80 is saved for every dollar spent on transmission in the AC, P2P, and MT transmission frameworks under our central decarbonization assumptions.

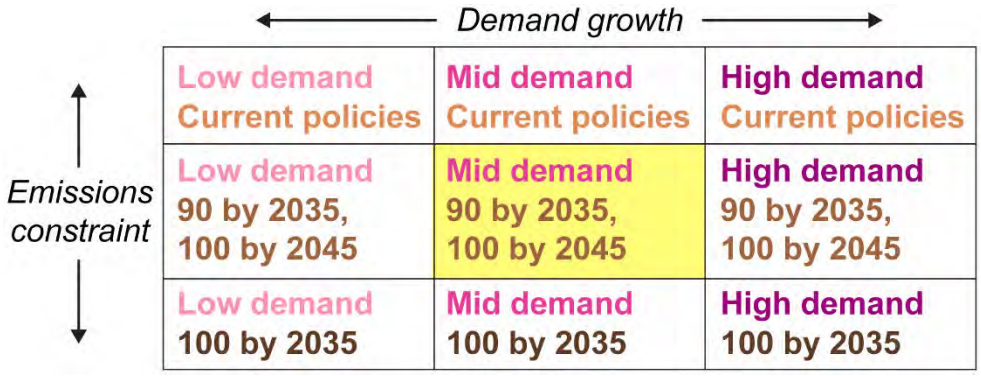


Figure II. Core demand and emissions assumptions.

The central demand and emissions assumption is highlighted in yellow.

The study finds rapid and significant growth in new transmission occurs in scenarios that achieve deep emissions reductions. Specifically, in the central decarbonization scenarios, the contiguous U.S. transmission system expands to 2.4–3.5 times the size of the 2020 system by 2050. This transmission occurs at all scales—including local, regional, and interregional—and for all regions of the country. Expansion of new long-distance transmission is concentrated in the central part of the country to enable increased access to wind and solar. Leveraging high-voltage direct current (HVDC) technologies, including advanced multiterminal converters, results in the greatest benefits. HVDC network solutions will require additional strengthening of AC networks. Similarly, the largest benefits of transmission are realized when interregional transmission is most substantial, including building across the interconnection seams. When U.S. electricity emissions are limited, future transfer capacities for many regions

exceed 30% of the region's peak demand and total aggregate U.S. interregional transfer capacity increases to 2.6–4.6 times the 2020 capacity by 2050.

The analysis includes scenarios with faster rates of decarbonization (100% by 2035) and higher demand growth (2.7%/year) than assumed in the central scenario. These scenarios find that electrification drives greater deployment of transmission and generation capacity. The benefits of transmission expansion scale with the level of electricity demand and rate of decarbonization. Under "High" demand growth, estimated savings from accelerated transmission expansion range from $710 billion to $970 billion, and coupling High demand with more rapid decarbonization can yield more than $1 trillion in electricity system cost savings.

Accelerated transmission deployment consistently reduces system cost across a spectrum of sensitivities with the greatest reductions found when hydrogen, carbon capture, and/or advanced nuclear are unavailable. The economic net benefits of transmission outweigh the incremental transmission costs in all scenarios, leading to a benefit-to-cost ratio of at least 1.5 across all sensitivity cases and exceeding 2.0 in many cases.

All 96 modeled future grid scenarios in the study—including those with approximately 90% of annual generation from variable resources—meet or exceed current industry resource adequacy standards. A variety of technologies supports resource adequacy. Interregional transmission—over spatial scales larger than weather systems—enables the sharing of variable renewables during days with limited local resource availability. In scenarios that allow coordination, transmission flows bidirectionally across many regional interfaces to support resource adequacy. With coordination, system costs through 2050 are lowered by $170 billion to $380 billion. Significant amounts of interregional transmission are built primarily to serve resource adequacy needs.

Lastly, the many scenarios and sensitivity cases in this chapter are also used to inform High Opportunity Transmission (HOT) interfaces that offer a starting point for further study. Spatial patterns in transmission expansion are similar across many sensitivity cases, and the HOT interfaces are defined as transmission expansion through 2035 between subregions that occurs in 75% of the sensitivity cases. Transmission projects that align with these HOT interfaces could be starting points for the grid expansion envisioned in this study.

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1 Introduction

The transmission grid has always played a critical role in the highly interconnected U.S. power system by delivering electricity from generators to load centers and supporting overall system reliability. As the U.S. generation mix undergoes major changes driven by clean energy policies and ambitions for deep decarbonization, the role of transmission is changing. Looking forward, how transmission might evolve to meet transformative generation changes while maintaining reliability is an open question. This chapter presents an analysis designed to answer this question for the contiguous U.S. electricity system.

Recent national decarbonization studies have collectively demonstrated the significant changes required in the U.S. transmission system to dramatically lower national greenhouse gas emissions. These studies include Denholm et al. (2022), the Net Zero America study (Larson et al. 2021), the Solar Futures Study (DOE 2021), Brown and Botterud (2021), and the North American Renewable Integration Study (Brinkman et al. 2021). Chapter 1 of this report and the Transmission Needs Study (DOE 2023a) summarize this body of work.

In addition to national-scale studies, regional planners also regularly conduct studies to examine future transmission expansion needs. These studies can lead to transmission expansion in utility or system plans and, ultimately, transmission procurement. Examples include California's long-term transmission plan (CAISO 2023a) and the Midcontinent Independent System Operator (MISO) Long Range Transmission Planning initiative (MISO 2022). Interregional transmission planning is more limited, but recent examples such as the MISO-Southwest Power Pool (SPP) Joint Targeted Interconnection Queue (SPP and MISO 2022) and the U.S. Department of Energy (DOE) Atlantic Offshore Wind Transmission Study (Brinkman et al. 2024) demonstrate interest in broader multiregional planning efforts.

The analysis presented in this chapter is motivated by the growing awareness of transmission expansion needs and applies a scenario approach like many of the above-referenced national-scale studies. However, this chapter focuses on transmission using a scenario framework, described in Section 2, designed to isolate the impacts of transmission on the U.S. electricity system. The scenario analysis presented in this chapter uses long-term capacity expansion and resource adequacy (RA) modeling to provide insights into the following questions:

- What is the role of transmission in decarbonizing the U.S. energy system?
- What are the economic trade-offs between different transmission futures and corresponding resource mixes?
- What mechanisms help ensure future low-carbon grids are resource adequate, and how does transmission support these mechanisms?
- Which interregional transmission expansions are commonly developed across a range of scenarios?

The focus of the National Transmission Planning Study (NTP Study) on identifying transmission that will provide broad-scale benefits to electricity customers and inform interregional and national strategies to accelerate decarbonization while maintaining system reliability includes examining transformative changes to the entire portfolio and considering a full suite of generation, storage, and transmission options. The capacity expansion modeling used here enables such evaluations and the examination of a range of future conditions, of which there are several important uncertainties—especially for achieving a zero-emissions grid. Incorporating RA tools in the analysis helps develop plausible resource mixes that can be more thoroughly examined for reliability. The scenarios presented in this chapter serve as the starting points for the more detailed power system modeling presented in subsequent chapters to begin to examine other aspects of reliability.

Section 2 describes the grid models used and the scenario design and assumptions, and the appendices provide additional explanation and detail. Results are presented in Section 3, with each subsection presenting a different group of scenarios. Section 3.1 presents results from scenarios that include enacted policies only. Section 3.2 examines how results change under different emissions targets and demand assumptions but uses default assumptions for other model parameters. Section 3.3 focuses on scenarios under central decarbonization assumptions and includes results across the full set of sensitivity cases. Conclusions are discussed in Section 4.

2 Methodology

Two National Renewable Energy Laboratory (NREL) models, the Regional Energy Deployment System (ReEDS)[2] and Probabilistic Resource Adequacy Suite (PRAS),[3] are used for the capacity expansion and RA analysis presented in this chapter. Both open-source models operate with zonal resolution covering the contiguous United States as their geographic scope (Figure 1a). This section briefly describes these two models and additional approaches used for the scenario analysis presented in this chapter.[4]

2.1 Model Descriptions

Regional Energy Deployment System (ReEDS). The ReEDS model is used to create future power system scenarios. ReEDS chooses from a large set of new generation, storage, and transmission options to identify the systemwide least-cost portfolio that meets future demand, grid reliability, and policy requirements. For this study, the model finds the optimal resource mix in 5-year steps between 2020 and 2050. The model applies a centralized planning approach but subdivides the contiguous United States into 134 zones to represent the grid network and to reflect region-specific generation, demand, and policies. For investment and dispatch modeling, each solve year includes 33 representative days with 4-hour resolution from weather year 2012 (P. R. Brown, Cole, and Mai forthcoming). The ReEDS documentation (Ho et al. forthcoming) and 2023 Standard Scenarios report (Gagnon et al. 2024) describe the model in greater detail. Appendix A details newer features of ReEDS used for this study.

Probabilistic Resource Adequacy Suite (PRAS). The PRAS model assesses the resource adequacy[5] of the scenarios generated by ReEDS. PRAS measures adequacy by performing Monte Carlo analysis of thermal generator outages[6] and hourly dispatch over 7 weather years (2007–2013) of renewable energy availability. Reliability metrics estimated by PRAS include loss of load probability (LOLP), loss of load expectation (LOLE), and expected unserved energy (EUE). This study uses the normalized expected unserved energy (NEUE)—EUE divided by total annual load—for the contiguous United States as the principal resource adequacy metric. PRAS has the same geographic scope and 134-zone resolution as ReEDS; however, thermal generator capacity within each zone is further subdivided into individual representative units to appropriately simulate generator outages.

[2] https://www.nrel.gov/analysis/reeds/
[3] https://www.nrel.gov/analysis/pras.html
[4] This chapter presents the methods, assumptions, and findings associated with the “round 2” scenarios of the NTP Study. Chapter 1 describes the primary differences between this round 2 capacity expansion analysis and the earlier round 1 analysis.
[5] The North American Electric Reliability Corporation (NERC) defines resource adequacy as “[t]he ability of the electric system to supply the aggregate electric power and energy requirements of electricity consumers at all times while taking into account scheduled and reasonably expected unscheduled outages of system components” (NERC 2022).
[6] Transmission outages are not modeled; however, interregional transfer capacity assumed in PRAS and ReEDS partially accounts for transmission contingencies. See Appendix A for further detail.

Integrated ReEDS-PRAS modeling. The optimal resource mix identified by ReEDS accounts for RA by including up to 30 "stress periods" in addition to the 33 representative days. The stress periods are the days with the highest EUE, among 7 weather years, as estimated by PRAS. The stress periods can change over time or between scenarios; for example, with increasing electrification, stress periods can include winter days with high heating demand as well as hot summer days with air conditioning demand. ReEDS iteratively augments the portfolio to meet a user-specified reliability target. This study uses a national RA target of 10 parts per million (ppm) NEUE. Although NEUE-based system planning has yet to become widespread, systems that do use NEUE-based planning tend to use NEUE targets in the range of 10 to 30 ppm (Alberta Electricity system Operator 2017; Electric Power Research Institute 2024; NERC 2024). Appendix B provides further detail on the combined use of ReEDS and PRAS.

Other models. Multiple upstream models are used to develop key inputs for ReEDS. The Distributed Generation Market Demand (dGen) model (Sigrin et al. 2016) simulates the customer adoption of rooftop photovoltaic (PV) systems. Distributed PV projections from dGen are exogenously input to ReEDS. The Renewable Energy Potential (reV) model (Lopez et al. 2024) provides the wind and solar resource potential used in ReEDS as well as the hourly renewable generation profiles used by all the models. Additional key datasets are described in Appendix A.

Transmission value analysis. This chapter's findings include results from an economic analysis of the scenarios, which assesses the relative costs between scenarios, the sources of those cost differences, and regional differences in costs and savings. This transmission value analysis primarily relies on a disaggregation of all the expenditures tracked in ReEDS—including generation, storage, and transmission capital and operating costs—through 2050 with additional adjustments to appropriately assess regional cost distributions.

2.2 Region and Transmission Terminology

The zonal ReEDS modeling represents the contiguous U.S. grid using 134 zones as shown in Figure 1a. These zones serve as the building blocks for larger regions for reporting purposes and to reflect policies and other factors. The zones conform to boundaries for the 48 states within the contiguous United States, which enables the representation of state clean energy policies.[7] This study focuses on 11 transmission "planning regions" that approximate Federal Energy Regulatory Commission (FERC) Order No. 1000 regions[8] and the Electric Reliability Council of Texas (ERCOT). The planning regions comprise aggregate model zones as shown in Figure 1c. These planning regions include the seven independent system operators (ISOs) and regional transmission organizations (RTOs) in the United States. The 11 planning regions are

[7] The District of Columbia (D.C.) is combined with the zone that represents Maryland.
[8] The South Carolina Regional Transmission Planning (SCRTP) region from FERC Order No. 1000 is included in the Southeastern Regional Transmission Planning (SERTP) in the analysis. Nonenrolled members of FERC planning regions and regions that are not part of FERC Order No. 1000 are *included* within the geographic boundaries shown in the figure.

fundamental to the scenario design (as discussed next). Because there is significant variation in geographic size between the 11 planning regions, the larger planning regions are further subdivided into “planning subregions” (Figure 1b).[9] Results are typically reported at the planning region and subregion levels and for the contiguous United States as a whole. Figure 1d also shows the three asynchronous interconnections in the contiguous United States.[10]

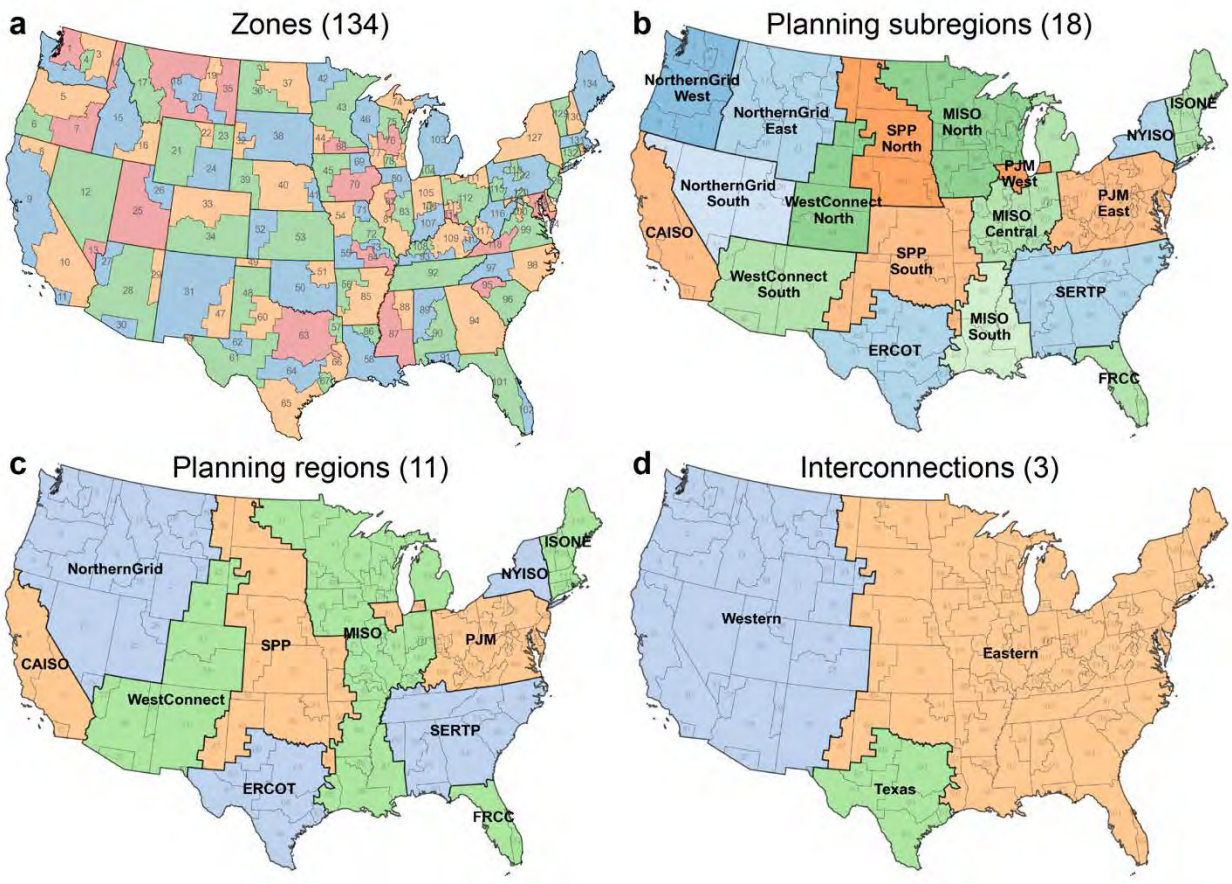


Figure 1. Hierarchy of regions used in the ReEDS model

Regional acronyms: California Independent System Operator (CAISO), Southwest Power Pool (SPP), Midcontinent Independent System Operator (MISO), New York Independent System Operator (NYISO), Independent System Operator of New England (ISONE), Southeastern Regional Transmission Planning (SERTP), Florida Reliability Coordinating Council (FRCC).

The geographic regions include Tribal lands within the boundaries shown in Figure 1. The modeling does not specifically exclude or encourage new transmission or generation projects on Tribal lands, but the study team recognizes that energy planning

[9] There are 18 total planning “subregions” in the contiguous United States. NorthernGrid and MISO are both subdivided into three subregions each. WestConnect, SPP, and PJM are subdivided into two subregions each.

[10] The Western and Eastern interconnections also include electrically connected regions in Canada and Mexico. Given the focus on the contiguous U.S. system, international imports and exports are exogenously specified in the modeling. The North American Renewable Integration Study (NARIS) (Brinkman et al. 2021) evaluated cross-border transmission expansion.

on such locations would require engagement, consultation, and participation from the relevant Tribes. Chapter 1 highlights Tribal engagement during the NTP Study.

Different categories and types of transmission, which are partly defined based on the regions, are modeled and reported:

- **Local** transmission refers to estimated transmission expansion *within* each of the 134 model zones. It includes transmission spur lines from wind and solar power plants to a point of interconnection (POI) and network upgrades or reinforcements needed beyond the POI to interconnect these plants to the grid. Local transmission capacity is modeled and tracked only for land-based wind, offshore wind, solar PV, and concentrating solar power (CSP). The costs to interconnect other resources are assumed to be $100/kilowatt (kW) (approximating recent interconnection costs for gas turbines (Seel et al. 2023)) whereas interconnection costs for wind and solar vary widely by location and can be several hundreds of dollars per kW (Lopez et al. 2024).[11]
- **Interzonal** transmission refers to the transfer capacity between any pair of zones from the 134 model zones. Unlike local transmission, interzonal transmission is not specific to any resource but instead serves systemwide needs. Existing transfer capacity between model zones is estimated based on a method summarized in Appendix A and presented by Brown et al. (2023). Expansion of interzonal transmission is a model decision because ReEDS co-optimizes generation, storage, and transmission simultaneously. Interzonal transmission can be based on high-voltage alternating current (AC) or direct current (DC) technology assumptions as specified in the scenarios. DC technology options modeled include back-to-back (B2B) ties across interconnections, line-commutated converters (LCC), and voltage source converters (VSC). In this report, interzonal transmission is presented by transmission technology (AC, B2B, LCC, VSC) or further subdivided as follows:
    - **Regional** transmission refers to interzonal transmission between zones within the same planning region.
    - **Interregional** transmission refers to the transfer capacity between two different planning regions.
    - **Seam-crossing** transmission refers to the subset of interregional transmission that crosses interconnection boundaries.

Unless otherwise noted, “transmission” capacity reported includes all types of transmission, including local and interzonal transmission, and is typically measured in terawatt-miles (TW-miles) to account for both the capacity and the distances of all transmission. *Interregional* transmission capacity is typically reported in gigawatts (GW) or terawatts (TW) to measure the transfer capacity across regional interfaces irrespective of the lengths of the transmission lines that cross these boundaries.

[11] Real 2022 dollars are used unless otherwise noted.

Transmission cost assumptions for local and interzonal transmission of various types are described in Appendix A.

2.3 Scenario Design

The scenario framework includes 96 scenarios modeled using the ReEDS and PRAS models.[12] These scenarios span a range of demand, policy, and technology conditions to assess the varied role and extent of transmission in the future U.S. energy system. The 36 "core" scenarios are all combinations of four transmission frameworks (Figure 2), three demand growth projections, and three levels of power sector emissions constraints (Figure 3). The remaining 60 scenarios studied include 15 different sensitivity cases, each modeled for the four transmission frameworks under the central demand growth and emissions constraint assumptions. No judgment is made about the relative likelihood of different scenarios or assumptions; instead, the scenarios are used to evaluate the role of transmission under a wide range of possible future conditions.

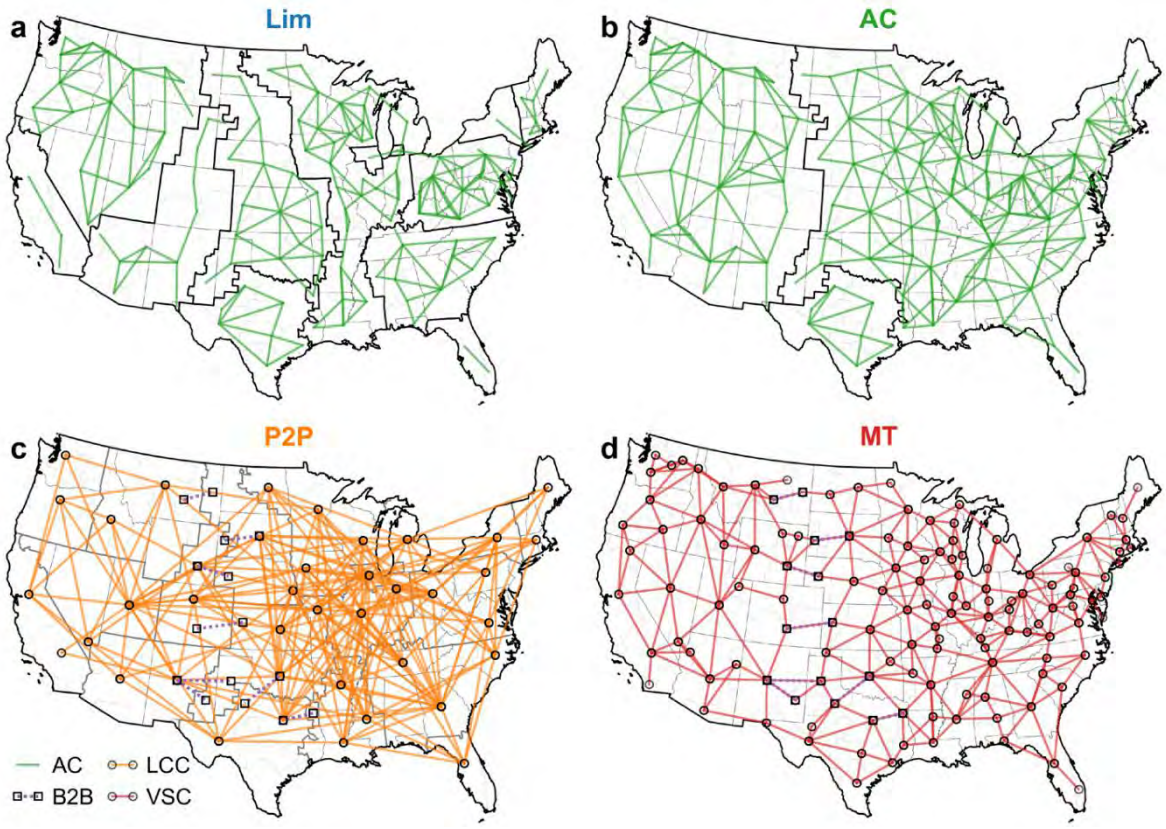


Figure 2. Expandable transmission interfaces in the four transmission frameworks considered in this study

Maps show interfaces where transmission capacity can be expanded under the corresponding transmission framework. AC interfaces in the AC framework are also allowed to be expanded in the point-to-point (P2P) and multiterminal (MT) frameworks but are not shown for clarity. Existing transmission interfaces are not shown. Allowable transmission types are AC (green), high-voltage direct current (HVDC) with line-commutated converters (LCC, orange), HVDC with voltage source converters (VSC, red), and back-to-back interties (B2B, purple dashed).

[12] Additional scenarios beyond these 96 are also modeled to address particular aspects as noted in the results.

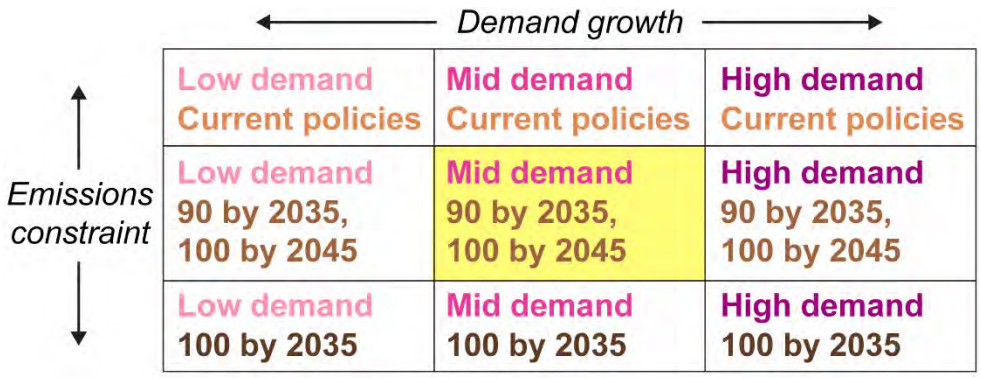


Figure 3. Core demand and emissions assumptions

The central demand and emissions assumption is highlighted in yellow.

2.3.1 Transmission frameworks

The primary comparisons are between transmission frameworks (Figure 2), which enable the impacts of transmission on the overall evolution of the U.S. power system to be isolated. The four transmission frameworks differ by the types of constraints on and options for new transmission expansions. Differences in the constraints on transmission expansion represent factors other than cost that can affect transmission capacity growth (e.g. siting and permitting, interregional coordination). These transmission frameworks span a wide range of possibilities, from a "Limited" framework with severe constraints on new expansion to highly coordinated planning frameworks that incorporate the latest high-voltage direct current (HVDC) technology options.

- **Limited (Lim):** The Limited framework serves as the reference or counterfactual to the other transmission frameworks. In this framework, no new *interregional* transmission is allowed, reflecting a lack of coordination between planning regions or other barriers that prevent expansions of interregional transfer capacities.[13] Within each planning region, *regional* transmission expansion is allowed but is assumed to use AC technology. The exception is for existing HVDC connections, which are allowed to expand using new DC lines. In addition to excluding new interregional transmission, an annual limit on new transmission expansion is also applied in this framework, based on the maximum annual transmission builds since 2014 (Wiser et al. 2023). Using fixed carrying capacity assumptions for different voltages (see Appendix A), this limit is 1.83 TW-miles/year and is applied to total transmission—of all types—installed nationally across the contiguous United States. Because this limit applies to local as well as regional transmission expansion, it creates a de facto constraint on the growth rate for new wind and solar.
- **Alternating Current (AC):** The AC framework does not include an annual limit to the amount of transmission expansion. It also allows for interregional transmission expansion except for seam-crossing transmission. All interzonal transmission is assumed to use AC technology and associated costs and losses

[13] This framework may be more restrictive than current practices given interregional transmission planning processes already underway.

except for existing HVDC connections, where DC expansion is allowed. Transmission cost assumptions are presented in Appendix A.

- **Point-to-Point (P2P):** The P2P framework allows for the same expansions as in the AC framework but also allows new HVDC opportunities. These include B2B DC ties across interconnections and 195 candidate P2P connections, including those between nonadjacent regions. These P2P candidates, shown in Figure 2, are identified based on locations with the highest wind resource and/or demand in each planning subregion. Only connections within 1,000 miles are considered. For these P2P candidates, HVDC line costs, which are lower than AC line costs,[14] and converter costs are based on LCC technologies.[15] Converters and lines are required to be identically sized.
- **Multiterminal (MT):** The MT framework allows for the same expansions as the AC framework but also includes options for HVDC expansion between adjacent zones. HVDC line costs are assumed to be the same as those for the P2P framework, but converter costs are slightly higher and based on VSC technology. However, unlike the P2P framework, converters and lines are independently sized by ReEDS in the MT framework. This approach enables more flexibility for a meshed network design, but this framework does not allow the 195 long-distance candidates from the P2P framework.[16]

The analysis primarily compares results from the AC, P2P, and MT frameworks, which are referred to as *accelerated* transmission frameworks because the rate of transmission expansions can exceed recent maximum annual builds, to the Limited framework. Both the P2P and MT frameworks extend the transmission options allowed in the AC framework by emphasizing HVDC technologies but represent distinct HVDC network designs.

2.3.2 Policy assumptions and emissions targets

How the role of transmission might change depending on decarbonization levels is a key question of the analysis. The baseline level of grid decarbonization is affected by enacted policies, which are included in all 96 scenarios.[17] These electric sector policies include state laws and federal clean energy tax incentives. State policies modeled include 28 renewable portfolio standards (RPSs)[18] and 15 clean energy standards. The assumptions for these factors are based on data from Barbose et al. (2023) and from stakeholder feedback received during the study. Technology-specific requirements from state RPS policies are also modeled, including offshore wind targets. The assumed mandated offshore wind deployment targets are based on analysis from DOE's

[14] HVDC line losses are also lower than AC losses, but additional losses are modeled for the AC-to-DC-to-AC conversions.
[15] Converter costs under the P2P and MT frameworks differ based on the assumed technologies used (LCC and VSC, respectively); however, the modeling is not prescriptive about which technology might be best suited.
[16] Connections between two nonadjacent zones would require multiple separate segments under the MT framework whereas P2P might have a direct connection with a shorter distance and lower costs.
[17] Existing policies as of June 2023 are modeled.
[18] Hawaii is not modeled. Washington, D.C. also has an RPS, and this policy is considered within the zone that includes both Maryland and D.C.

Offshore Wind Market Report: 2023 edition (Musial et al. 2023).[19] Electric sector greenhouse gas (GHG) emissions policies for the Regional Greenhouse Gas Initiative states and California are also included. State retirement policies for existing plants and bans for new nuclear or fossil capacity are also included (Gagnon et al. 2024). County and other local siting ordinances, tracked from Lopez et al. (2023), for new wind and solar development are also modeled as part of the wind and solar resource potential inputs to the model (Lopez et al. 2024).

Federal policies modeled include many of the clean energy tax incentive provisions from the Inflation Reduction Act (IRA) of 2022 and the Bipartisan Infrastructure Law of 2021.[20] The IRA tax incentives include production and investment tax credits for new wind, solar, other renewable energy, energy storage, and carbon capture and storage (CCS).[21] Steinberg et al. (2023) document the assumptions used to represent these policies in ReEDS. The tax credit level and period when the IRA incentives are available vary by technology. The wind, solar, and storage tax credits expire depending on the annual U.S. power sector emissions; the IRA specifies these credits expire when annual emissions are below 25% of 2022 levels or in 2032, whichever is later. For some scenarios, the IRA tax credits phase out as written, and for others the wind, solar, and storage tax credits are assumed to expire in 2032 to facilitate the comparison of scenarios without confounding changes in tax policy conditions.

In addition to the enacted policies, decarbonization scenarios are modeled using national emissions constraints (Figure 3). The following three power sector emissions trajectories are used in the scenarios:

- **Current policies:** Current policies include enacted state and federal policies as of June 2023 as described previously. No other policies, such as a national constraint on emissions, are included.
- **90% by 2035:** In addition to enacted policies, a national annual limit on power sector carbon dioxide equivalent (CO_2(e)) emissions is applied in the 90% by 2035 scenarios.[22] This limit is set to achieve 90% reductions from 2005 levels by

[19] These assumptions result in 47 GW of prescribed offshore wind capacity by the mid-2030s, all of which are off the Atlantic coast except for 4.7 GW of offshore wind by 2035 in the Pacific based on the Base case from the California Public Utilities Commission (2022).
[20] Only major legislation and mandates are included in the modeling. Nonbinding and voluntary targets from states, corporations, or utilities are not included. The modeling is not comprehensive of all policies, especially those applied at the local level. The assumptions also represent a snapshot in time of the policy environment, which can change rapidly.
[21] Tax credits for hydrogen technologies are not included in this analysis because guidance for these tax incentives was not released at the time this analysis was completed. Clean Air Act section 111 standards are not included because they were also not finalized when this analysis was completed.
[22] The limit applies to direct CO_2 emissions from fossil-fuel-fired power plants as well as from upstream CO_2(e) methane emissions. The modeling assumes a 100-year global warming potential of 34 to estimate the CO_2(e) of methane and assume a leakage rate of 2.3% in 2021 (Alvarez et al. 2018), declining by 30% to 1.6% in 2030 and thereafter (Denholm et al. 2022).

2035 and 100% reductions by 2045.[23] The limit declines linearly from 2025 to 2035, declines linearly between 2035 and 2045, and stays at 0 million metric tons (MMT) CO_2 after 2045. Figure 4 shows the emissions trajectory used in these scenarios along with historical emissions for context. This trajectory is used under the central decarbonization assumptions.

- **100% by 2035:** The emissions limit in the 100% by 2035 scenario is applied similarly to the 90% by 2035 scenario, except the trajectory achieves zero emissions by 2035 and stays at that level through 2050 (Figure 4). The 2035 zero emissions limit is consistent with the U.S. carbon-free electricity by 2035 target (Executive Office of the President 2021).

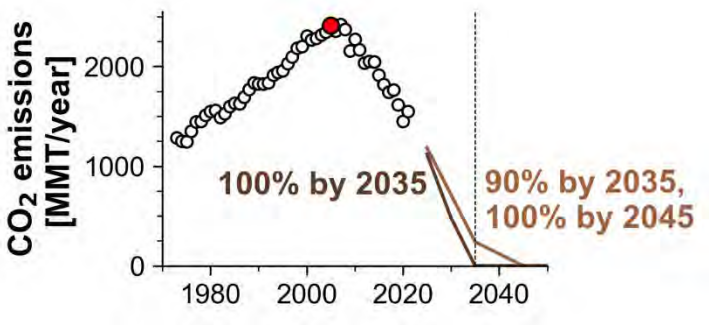


Figure 4. Emissions constraints under grid decarbonization scenarios

Historical emissions are from EIA (2024b). Power sector emissions in 2005 are 2,411 MMT CO_2.

2.3.3 Electricity demand growth assumptions

Historical and future load growth are impacted by macroeconomic factors, energy efficiency, and electrification or potential new sources of demand (e.g., growth in data centers). To account for significant uncertainties with these factors, three demand scenarios spanning a wide range of growth possibilities are modeled (Figure 5). The compound annual growth rate for demand in these scenarios varies from 0.9%/year to 2.7%/year (2021 to 2050) and is largely correlated with the rate of electrification and corresponding reductions in direct emissions from end-use sectors such as transportation, buildings, and industry.[24] For context, U.S. load grew by 1.1%/year during the prior 30 years (1992 to 2021) but experienced much flatter growth during the past 15 years (0.1%/year) and higher growth (2.8%/year) over the longer (1962–2021) period. The three demand trajectories are based on demand-side modeling from Evolved Energy Research and calibrated using 2021 state-level demand data from EIA (2021):

- **Low-Demand:** The Low-Demand trajectory is from the "Baseline" case from the 2022 Annual Decarbonization Pathway (Haley et al. 2022), which largely follows

[23] Noncaptured CO_2 from fossil with CCS plants count against these emissions limits; however, these emissions can be offset by bioenergy with CCS (BECCS) options or other negative emissions technologies when allowed. Direct air capture (DAC) is not included in the core scenarios but is included in a sensitivity. Emissions from fossil plants without CCS are not allowed to be offset in the definition used here.

[24] Appendix A shows the estimated end-use emissions by sector in the three demand cases.

EIA's Annual Energy Outlook (AEO) 2022 Reference case (EIA 2022). It does not include electric vehicle tax credits and other electrification or clean energy tax incentives from the IRA. Annual demand grows by 0.9%/year from 2021 to 2050 under Low-Demand.

- **Mid-Demand:** The Mid-Demand trajectory is more representative of enacted policies because it includes the electrification incentives for various end-use sectors from the IRA. This case features "moderate" electrification assumptions as used in Haley et al. (2023).[25] Load growth is 2.0%/year. This trajectory is used as the central decarbonization assumption.
- **High-Demand:** The High-Demand trajectory includes substantial electrification consistent with achieving net zero energy emissions by 2050. This assumption is from the "Central" case from the 2022 Annual Decarbonization Pathway (Haley et al. 2022). Because of high electrification, demand grows by 2.7%/year, resulting in 2050 annual demand that approximately doubles national demand from 2021.

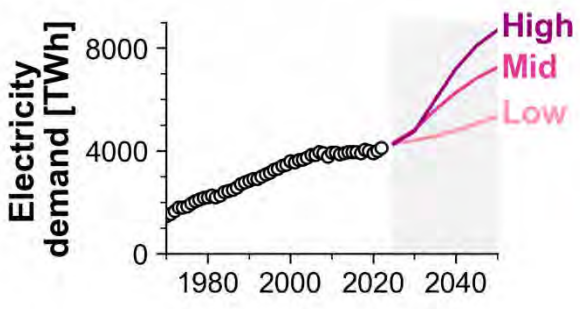


Figure 5. Annual demand assumptions for the contiguous United States

Historical demand shown is electricity sales to ultimate customers from EIA (2024b).

Hourly demand profiles also change over time and vary across the Low-, Mid-, and High-Demand trajectories. Electrification of buildings under Mid- and High-Demand results in winter demand peaks that grow faster than summer peaks in many regions. Figure 6 shows these changes in the demand profile over time for the contiguous United States, but the shifts toward winter peaks are even starker in colder regions. Demand data used in the models are at hourly resolution for each state; all zones within a state share the same normalized load profile, but state annual demand is partitioned based on historical distributions of load.

[25] Specifically, the "Current Policy" scenario from Haley et al. (2023) is used for the Mid-Demand case.

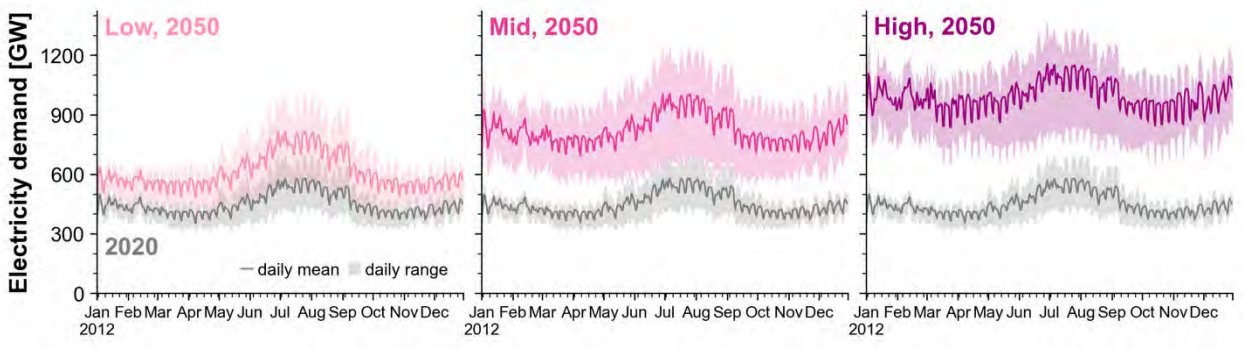


Figure 6. Daily demand profiles for the contiguous United States in 2020 and 2050

The demand profiles shown use 2012 weather.

2.3.4 Other default assumptions

Aside from the differences in transmission framework, power sector emissions target, and demand outlined previously, all other assumptions are the same across the 36 core scenarios. These default assumptions include technology cost and performance assumptions from the NREL Annual Technology Baseline (ATB) 2023 Moderate case (National Renewable Energy Laboratory 2023) (see Appendix C) and fuel costs from the EIA AEO 2023 Reference case (EIA 2023a). Distributed rooftop PV adoption is also held constant between scenarios and is assumed to reach 130 GW_{AC} by 2035 and 170 GW_{AC} by 2050 (Gagnon et al. 2024), compared with 48 GW_{AC} of small scale PV in 2023 (EIA 2024a).

For CO_2 transport and storage costs, a uniform $15/metric ton cost for all regions is applied, without limits on the amount of CO_2 that could be injected.[26] Hydrogen storage is modeled explicitly to ensure sufficient storage capacity for the daily balancing of H_2 production, storage, and use.[27] However, all hydrogen must be used in the same zone in which it is produced; transport of H_2 between zones is not allowed in any scenario. Further work is needed to compare trade-offs between electricity transmission and transport of other energy carriers. Appendix A details the hydrogen representation used for this study.

Unless otherwise noted, all other assumptions are from the NREL Standard Scenarios 2023 Mid-case (Gagnon et al. 2024).

2.3.5 Sensitivity cases

In addition to the core scenarios, 15 sensitivity cases are modeled under all four transmission frameworks. These 60 sensitivity cases all assume 90% by 2035 power sector emissions trajectory and Mid-Demand growth—which represent the central decarbonization conditions. Table 1 summarizes the sensitivity cases.

[26] Brown et al. (forthcoming) presents the endogenous model representation for CO_2 transport and storage. A test scenario using this capability resulted in similar findings to those presented here. Scenarios with greater CCS deployment could have different implications.
[27] No hydrogen demand for industry, transportation, or other uses outside for electricity generation are considered; all reported hydrogen production and use in the scenarios are for grid applications.

Table 1. Sensitivity Cases

Name	Description
PV+Battery Low Cost	PV and battery technologies follow the ATB 2023 Advanced cost and performance projections (National Renewable Energy Laboratory 2023).
Wind Low Cost	Land-based and offshore wind technologies follow the ATB 2023 Advanced cost and performance projections (National Renewable Energy Laboratory 2023).
Electrolyzer Low Cost	Electrolyzer costs are based on DOE (2023b). Electrolyzer costs in the core scenarios decline linearly from $1,750/kW in 2022 to $550/kW in 2030 and stay constant thereafter; costs in this sensitivity case undergo further linear declines from $550/kW in 2030 to $157/kW in 2050.
+Nuclear SMR +DAC	Assumes nuclear small modular reactor (SMR) and direct air capture (DAC) technologies are commercially available. Nuclear SMR costs are from the ATB 2023 Moderate case (National Renewable Energy Laboratory 2023) and DAC costs are from Brown et al. (forthcoming). DAC can be used to offset emissions from fossil CCS plants.
No Interface Expansion Limit	In all other scenarios, a 30-GW limit is imposed for total interzonal capacity (combined existing and new, AC and DC). This sensitivity case eliminates this maximum level.[28]
Transmission 2x Cost	Interzonal $/megawatt-mile (MW-mile) transmission costs are doubled for all interfaces for both AC and DC capacity. Default transmission costs are presented in Appendix A.
No RA Sharing	Requires each of the 18 subregions to meet adequacy needs locally; no trades are allowed across subregion boundaries during the modeled stress periods. This represents a lack of interregional coordination for resource adequacy. (See Appendix A for details.)
Siting Limited	Uses more-constrained siting supply curves for land-based wind and utility PV, based on "Limited Access" from Lopez et al. (2024), as opposed to the default "Reference Access." This reduces the technical potential from 11.1 TW to 5.9 TW for wind and from 112 TW to 58 TW for PV. Reductions are not uniform by region.
CTS High Cost	CO_2 transport and storage (CTS) costs are assumed to be $36/metric ton instead of $15/metric ton under default assumptions. These assumptions are based on Grant et al. (2019) as discussed in Brown et al. (forthcoming).
Many Challenges	Uses higher technology costs for PV, wind, battery, CCS, and nuclear technologies based on projections from the ATB 2023 Conservative case (National Renewable Energy Laboratory 2023). Uses the more-constrained supply curves for wind and utility PV as in the "Siting Limited" sensitivity.
No H_2	Hydrogen electrolyzers and combustion turbines (CTs) are not available.

[28] The 30-GW limit is based on iterations with the preliminary nodal modeling in the study that indicated expanding beyond this level would be technically challenging.

Name	Description
No CCS	CCS technologies are not available.
No H_2 or CCS	Hydrogen and CCS technologies are not available.
No H_2 or New Nuclear	Hydrogen technologies and new nuclear deployment are not available.
Climate	Modifies demand, solar, and wind profiles to be based on future weather conditions developed from a global climate model and downscaled (Buster et al. 2023). Hydropower capacity during stress periods is assumed to be reduced by 20% in 2050. Summer capacities for thermal generators and transmission for 2050 are derated by 15% and 5%, respectively. Capacity derates ramp linearly from 0% in 2025 to these values. (See Appendix A for details.)

2.4 Modeling and Analysis Limitations

The analysis examines the future role of transmission using sophisticated power sector tools; however, there are limitations of the analysis especially given the transformative and wide-ranging scenarios examined and the very large and complex nature of the U.S. electricity system. Here, several important limitations of the modeling in this chapter are discussed.

Behavioral, institutional, and regulatory aspects are not fully reflected in the models. The models apply a centralized economic optimization approach rather than the more-complex decision-making reality in today's energy system. Diverse decision makers can have different objectives and considerations that would lead to different planning and operational outcomes than those found by the models. Select sensitivity cases partially address interregional coordination and uncertainties with siting and permitting renewable energy projects. Additional analysis is needed to study these issues in greater depth and to quantify their impacts.

Energy planning for transmission and other electricity resources is complicated by the limited foresight of future policy, market, and technology conditions and the long-lived nature of these assets. These uncertainties are partially captured through the wide range of scenarios modeled; however, the capacity expansion modeling used here does not reflect the limited foresight conditions of reality. Specifically, ReEDS finds the optimal resource mix sequentially for each 5-year increment from 2020 to 2050 with no foresight on how policies, technologies, or fuel prices might change. This would give a suboptimal solution relative to an intertemporally optimized model that sees the full 30-year period altogether. On the other hand, ReEDS assumes the construction, permitting, and other planning and approval efforts are successfully executed prior to the modeled installation dates. This perfect "construction" foresight approach does not account for manufacturing, supply chain, and workforce needs that may impact the rate of technology deployment. The modeling does not directly reflect all these complexities—either inside or outside of the electricity sector—that may be required to realize these scenarios. Similarly, perfect foresight is assumed in the dispatch decisions from ReEDS and PRAS.

Comprehensively evaluating full economywide and broader societal cost and benefits of the scenarios is outside the scope of this analysis. The analysis compares differences in direct power system expenditures, nationally and by region, to evaluate the economic viability of transmission under a range of future conditions. This includes all expenditures for the bulk power system but does not include distribution system expenditures or an economic evaluation of the demand-side sectors under the various electrification futures modeled. Moreover, the cost, benefits, and impacts of GHG emissions levels or other air pollution are out of scope. Finally, distributional impacts to different demographic groups and stakeholders are also not evaluated in this analysis.

Although the analysis includes many scenarios, not all possibilities are analyzed. Importantly, the modeling does not explicitly include all technology options. For example, the cost assumptions for new transmission are based on estimates for greenfield projects; transmission upgrades or grid-enhancing technologies (GETs) that could yield expanded transfer capacity at potentially lower costs are not directly modeled in ReEDS. Some of the expanded transmission capacities reported can be realized through these other options. ReEDS modeling also includes diurnal and seasonal (hydrogen) energy storage (see Appendix A) but does not explicitly include other long-duration storage options. The scenarios also include increases in rooftop PV capacity, but other distributed energy resources, demand response, and demand-side flexibility options are not modeled.[29] The omission of demand flexibility—including managed electric vehicle charging—could be particularly important with respect to the RA results presented.

This chapter's analysis includes RA modeling but does not fully consider other elements of reliability, such as operational reliability and resilience. Resource adequacy is considered through the integrated ReEDS-PRAS modeling, which includes generator outages and variability, weather-driven variability, a wide range of long-term demand projections, and approximations for transmission contingencies through interregional capacity derates. However, generator fuel supply limits, correlated outages, and transmission outages are not modeled. Appendix B discusses these and other limitations of the RA analysis. Subsequent chapters supplement the analysis with other elements of reliability not considered by the capacity expansion models used in this chapter.

Further study is needed to examine these important aspects.

[29] Sensitivity cases with higher distributed PV levels were modeled in earlier stages of the study but had less impact on the scenario outcomes than many other sensitivity cases presented here.

3 Results

3.1 Current Policies

This section reports findings from scenarios assuming current policies (as of June 2023) only. Scenarios with additional constraints on national carbon emissions are presented in subsequent sections.

3.1.1 Benefits from large-scale transmission expansion include billions of metric tons of avoided CO_2 emissions

Accelerating transmission expansion beyond the historical rate specified in the Limited framework has a strong effect on electricity sector CO_2 emissions under current policies (Figure 7). Under mid demand, modeled electricity sector emissions in 2035 are roughly 810 MMT CO_2 per year in the Limited framework and 440–460 MMT/year in the three accelerated transmission frameworks (AC, P2P, MT), a 44%–45% reduction. Annual emissions reductions from accelerated transmission are even larger in 2050, roughly 56%–61%. On a cumulative (2025–2050) basis, the accelerated frameworks avoid 10.2–11.2 billion metric tons of CO_2 (43%–48%) relative to the Limited framework.

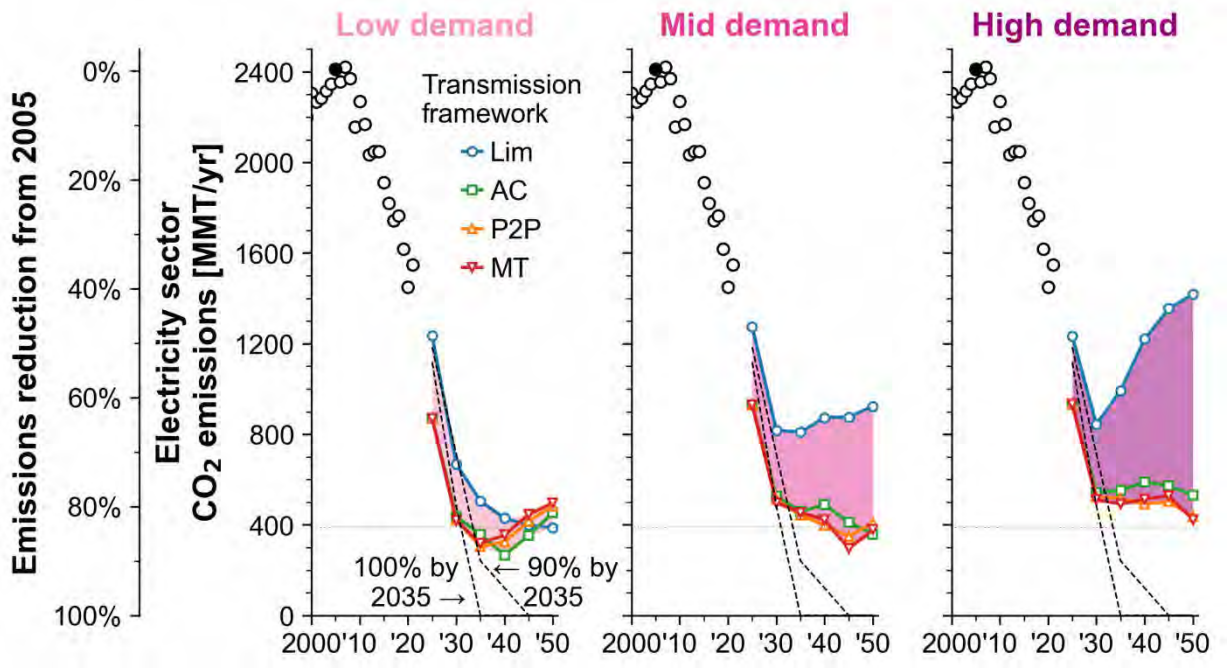


Figure 7. Electricity sector CO_2 emissions under current policies across demand assumptions

The 90% by 2035/100% by 2045 and 100% by 2035 emissions trajectories are indicated by black dashed lines. The IRA tax credit phaseout threshold (75% CO_2 emissions reduction compared to 2022) is indicated by gray dotted lines. Historical emissions (black circles) are from EIA (EIA 2024b). The shaded area represents the change in emissions from the Limited transmission framework.

Notably, even without new policies, each of the three accelerated transmission frameworks is on track for CO_2 emissions reductions on par with both the 90% by 2035 and 100% by 2035 emissions trajectories through 2030 (Figure 7). The Limited transmission framework, by contrast, reaches at most a 66% emissions reduction

relative to 2005. As discussed below, under current policies, emissions reductions stall or even reverse after 2030 as a result of the phaseout of the IRA tax credits (with low demand) or accelerated demand growth in the decades after 2030 (with mid or high demand).

Modeled emissions also depend strongly on the assumed demand growth. In the Limited transmission framework, 2050 CO_2 emissions with High-Demand are 3.7 times the emissions under Low-Demand (Figure 7a,c). The annual emissions reductions from accelerated transmission under high demand are 44%–50% in 2035 (440–500 MMT CO_2/year) and 62%–70% in 2050 (890–990 MMT CO_2/year), resulting in cumulative CO_2 savings of 14.3–15.7 billion metric tons (48%–52%). Conversely, cumulative CO_2 savings are more modest with Low-Demand (3.1–3.8 billion metric tons, or 21%–26%). This comparison applies only to electricity sector emissions; different demand trajectories have very different direct end-use emissions (Appendix A).

The emissions trends are complicated by the phaseout conditions for the IRA tax credits; as written, the credits start phasing out in 2032 or the year in which electricity sector emissions drop 75% below their 2022 level, whichever is later. The three accelerated transmission frameworks trigger the tax credit phaseout under Low-Demand growth, leading to increasing emissions between 2040 and 2050, whereas the Limited transmission framework never reaches 75% emissions reductions and thus never triggers the phaseout.

Emissions reductions from accelerated transmission expansion are driven by increased wind and solar deployment

Wind and solar deployment are significantly accelerated in the AC, P2P, and MT transmission frameworks compared to the Limited framework (Figure 8) because the annual deployment limits on local interconnection capacity (required for new wind and solar) and long-distance transmission are removed. Under Mid-Demand Current Policies assumptions, wind capacity expands to 5.8 times its 2020 capacity by 2050 in the Limited framework and 8.6–8.8 times in the accelerated transmission frameworks; solar capacity expands 10 times in the Limited framework and 14–17 times in the accelerated transmission frameworks. In 2035, wind capacity is 34%–42% higher in the accelerated transmission frameworks than in the Limited framework; solar capacity is 32%–59% higher. The share of total 2050 generation from variable renewable energy (VRE)—wind and solar combined—expands to 55% in the Limited framework and 77%–79% in the three accelerated transmission frameworks.

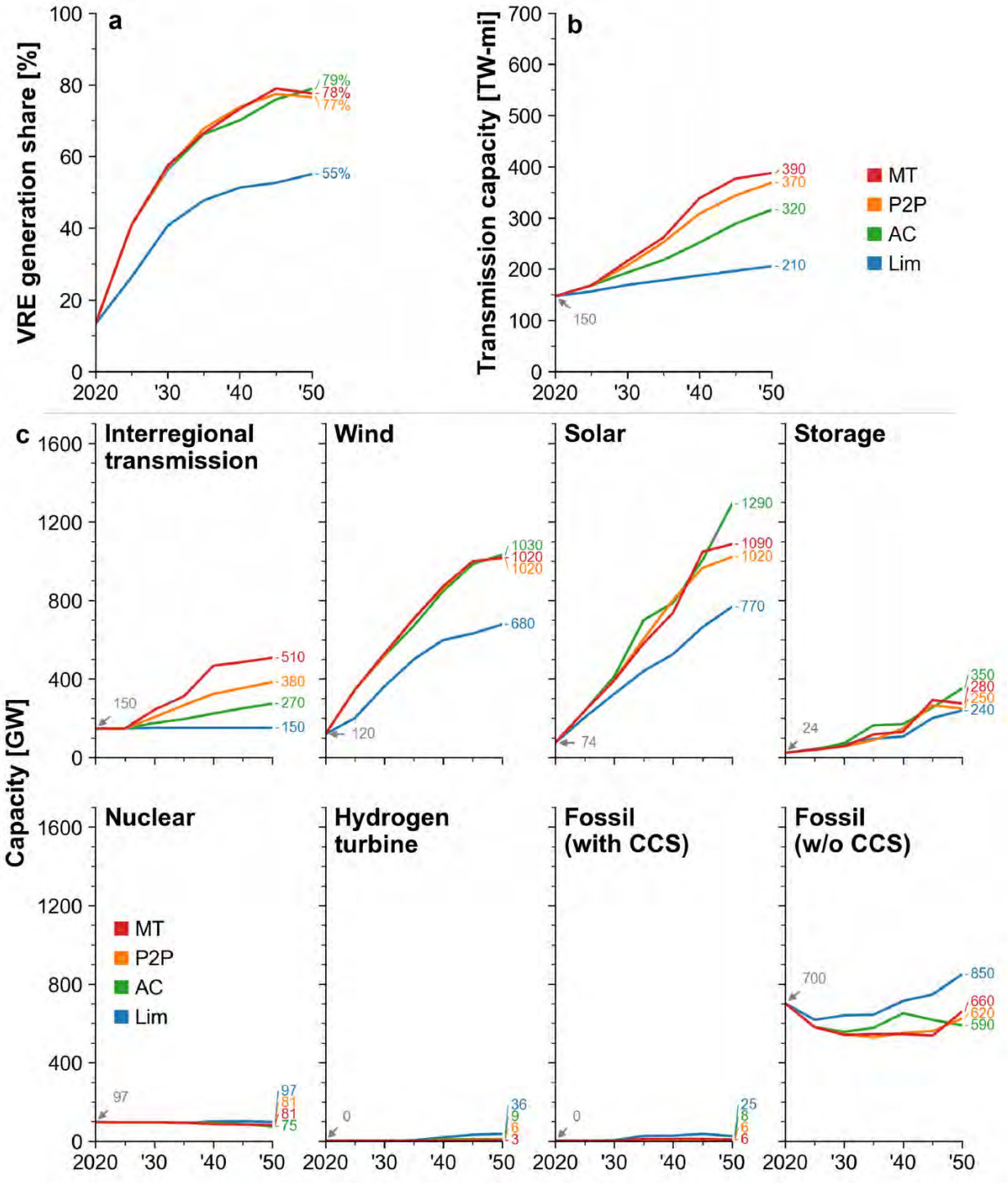


Figure 8. Trajectories of VRE share (a), transmission capacity (b), and nameplate capacity (c) under mid demand and current policies

"Total" transmission capacity (Figure 8b), including both local interconnection capacity (spur lines and network reinforcement associated with new wind and solar additions) within the 134 ReEDS model zones and long-distance interzonal transmission capacity between the model zones, is reported in units of TW-miles. Compared to the estimated

2020 capacity of ~150 TW-miles, total transmission capacity in 2050 grows to 1.4 times in the Limited framework, 2.1 times in the AC framework, 2.5 times in the P2P framework, and 2.6 times in the MT framework. “Interregional” transmission (Figure 8c) is shown in GW and represents the total bidirectional transfer capability between the 11 planning regions (Figure 1c). Compared to the estimated 2020 transfer capacity of ~150 GW, interregional transmission capacity does not expand in the Limited framework (as required by the scenario design, discussed in Section 2.3.1) and grows to 1.9 times in AC, 2.6 times in P2P, and 3.5 times in MT.

Even with expanded transmission, current policies are insufficient to fully eliminate power sector emissions, especially in futures with high demand growth

Though modeled power sector emissions are in line with the 90% by 2035 and 100% by 2035 trajectories through 2030, they diverge over the subsequent two decades (Figure 7). Fossil capacity is higher in 2050 than in 2020 in the Limited framework because the total transmission deployment limit of ~1.83 TW-miles/year substantially constrains the deployment of competing wind and solar technologies. Even in the accelerated transmission frameworks, fossil capacity in the Mid-Demand scenarios never drops more than 25% below its 2020 capacity under current policies (Figure 8), and electricity sector CO_2 emissions never drop more than 81% below their 2022 level (Figure 7).

3.2 Demand Growth and Emissions Constraints

This section presents findings from the core scenarios (Figure 3), including those that span multiple demand growth trajectories and different constraints on national power sector emissions. Unless otherwise noted, in the following results the IRA tax credits are assumed to expire in 2032 to facilitate more direct comparisons using the same policy conditions.

3.2.1 Rapid and significant growth in new transmission capacity occurs in scenarios that achieve deep emissions reductions

Applying an emissions requirement significantly expands the deployment of transmission in frameworks that allow transmission expansion (Figure 9). Under Mid-Demand assumptions, 2050 transmission capacity is 37%–68% higher with a 90% by 2035 emissions requirement than with Current Policies for each of the three accelerated transmission expansion frameworks. The Limited transmission framework is bound by the 1.83 TW-miles/year deployment constraint in nearly all scenarios.[30] Because the 90% by 2035 and 100% by 2035 scenarios achieve 100% emissions reductions by 2045 at the latest, the 2050 transmission capacity does not change significantly between these scenarios when demand scenario and transmission framework are held constant. However, near-term transmission deployment is accelerated in the 100% by 2035 scenarios: 2035 transmission capacity is 15%–34% higher in the 100% by 2035 scenarios than in the 90% by 2035 scenarios for the three accelerated transmission frameworks.

[30] With low demand and current policies, the annual transmission growth constraint of the Limited framework is not reached.

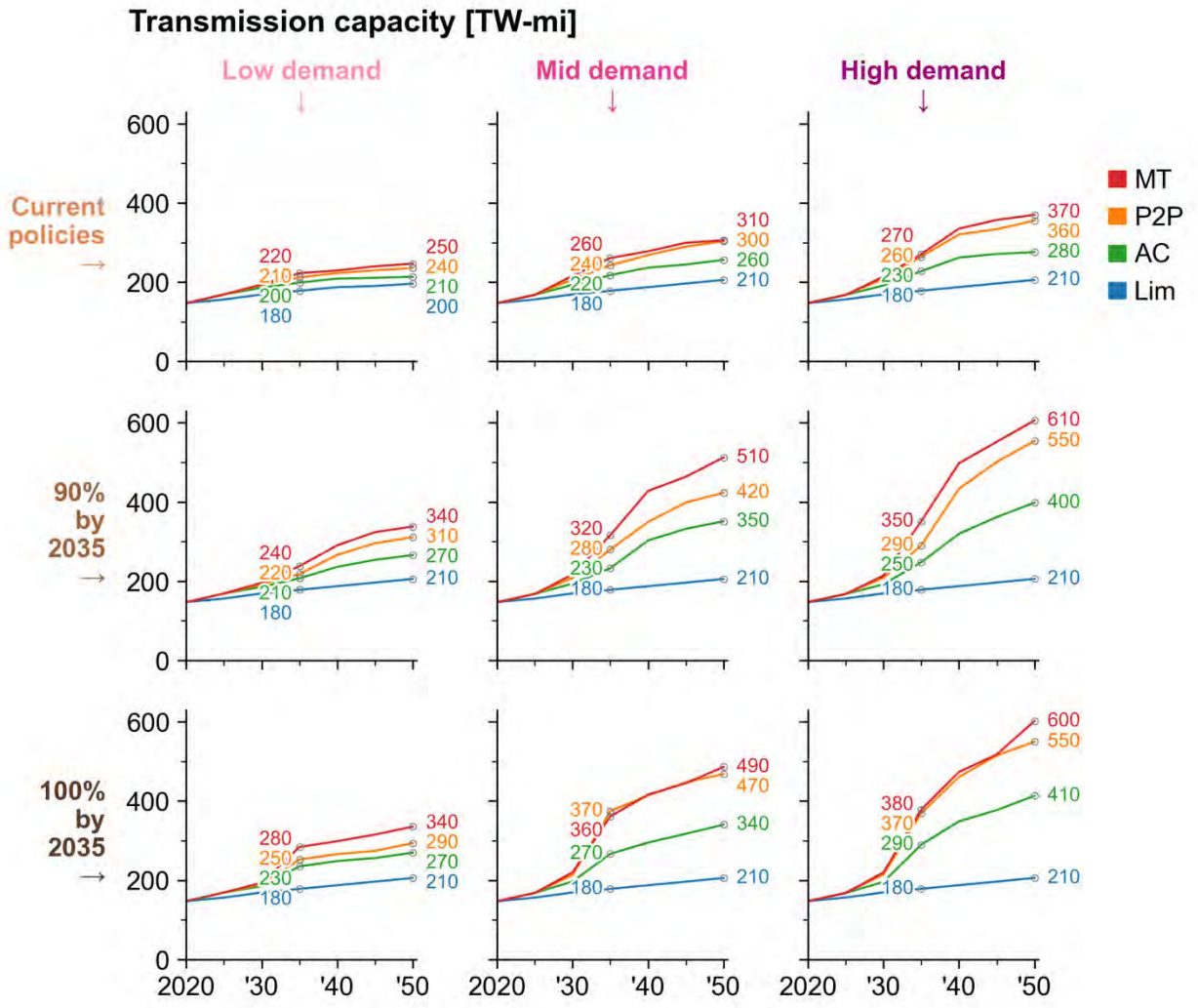


Figure 9. Total transmission capacity as a function of demand (columns) and emissions constraint (rows)

Total transmission capacity includes local interconnection capacity (spur lines and network reinforcement) within the 134 ReEDS zones and long-distance interzonal transmission capacity between ReEDS zones. For this plot, the IRA tax credit is assumed to begin phasing out in 2032 for all scenarios (including for current policies), irrespective of emissions, to facilitate comparison across scenarios while keeping policy assumptions constant.

For context, Figure 10 shows the average transmission growth rate between 2025 and 2050 compared to different benchmarks for historical transmission deployment. In the central Mid-Demand 90% by 2035 scenario, annual transmission additions in the three accelerated transmission frameworks range from 2.0 to 3.8 times the maximum annual rate of transmission deployment observed in the United States since 2009. Alternatively, comparing the modeled rate of annual transmission deployment to individual HVDC links that have been built in the past in a collection of countries shows this rate of growth equates to the addition of 2.7–5.1 “Pacific-DC Intertie” links (built in the United States in 1970 and upgraded since) per year (Pierre et al. 2019), 0.8–1.5 “Rio Madeira” links (completed in Brazil in 2014) per year (Hitachi 2022), or one “Changji-Guquan” link (completed in China in 2019) every 1.8–3.3 years (Hitachi 2020).

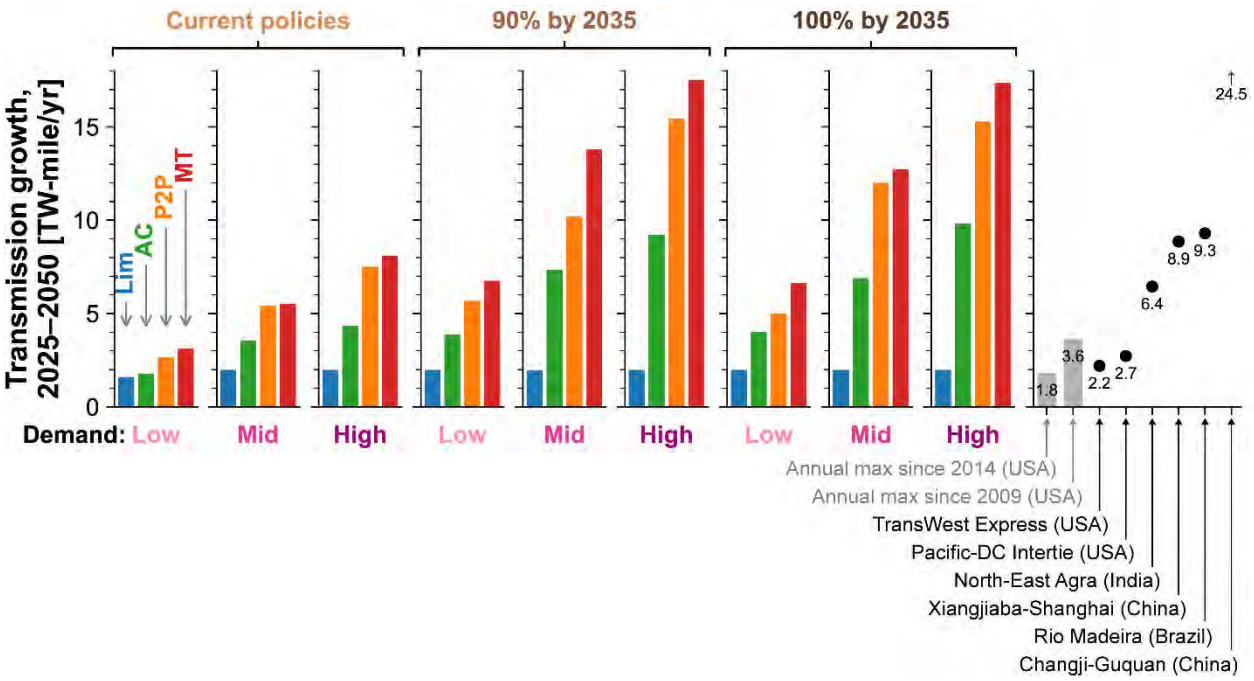


Figure 10. Total transmission growth rate in TW-miles/year as a function of demand, emissions constraint, and transmission framework

The gray bars for "Annual max since 2009" and "Annual max since 2014" refer to U.S. transmission additions as discussed in Wiser et al. (2023). The filled markers indicate individual historically constructed HVDC projects for scale (Pierre et al. 2019; TransWest Express 2024; Power Technology 2020; Hitachi 2020; 2022; 2024).

Electrification drives greater deployment of transmission and generation capacity

The assumed level of demand growth has a significant impact on total transmission deployment. Relative to 2020 transmission capacity, the 2050 transmission capacity in the three accelerated transmission scenarios grows from 1.5 to 1.7 times for low demand to 1.9–2.5 times for high demand under current policies (Figure 9). Combined with a decarbonization policy, the impact of demand growth is even stronger: With 90% by 2035 and 100% by 2035 emissions reductions, 2050 transmission capacity grows from 1.8 to 2.3 times its 2020 level for low demand to 2.7–4.1 times for high demand. Scenarios with high demand through electrification and that achieve 100% grid emissions reductions approximate net zero emissions for the U.S. energy system as a whole (Section 2.3.3).

As with total transmission capacity, demand growth and decarbonization policy are strong drivers of interregional transmission deployment (Figure 11). Interregional transmission capacity, which is defined as the capacity between the 11 planning regions in Figure 1c, grows to 1.5–2.7 times its 2020 capacity by 2035 in the three accelerated transmission frameworks in the Mid-Demand 90% by 2035 scenario and 1.6–3.3 times in the High-Demand 100% by 2035 scenario. By 2050, these ranges grow to 2.6–4.6 times in the Mid-Demand 90% by 2035 scenario and 2.6–5.3 times in the High-Demand 100% by 2035 scenario.

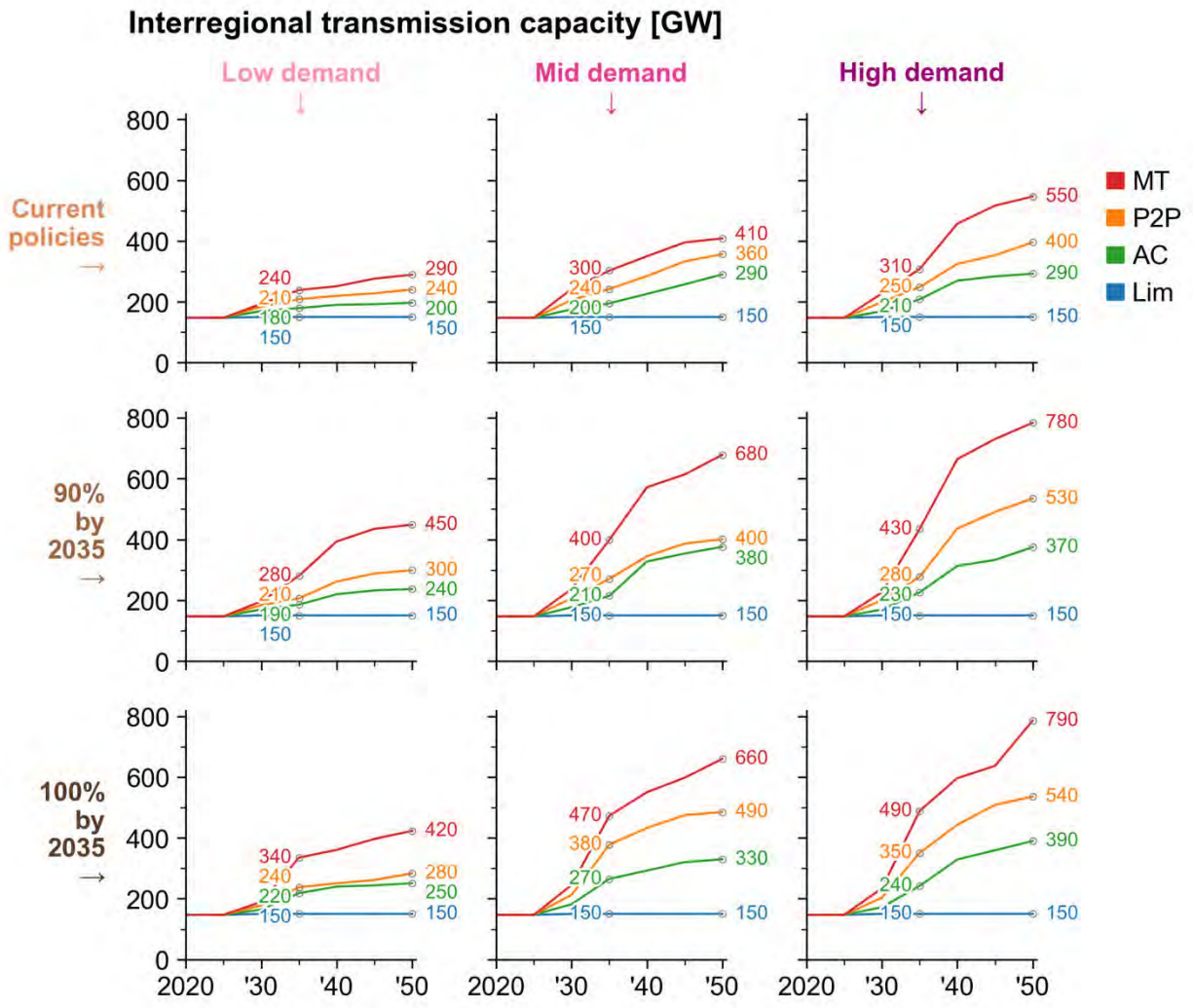


Figure 11. Interregional transmission capacity as a function of demand (columns) and emissions constraint (rows)

"Interregional" transmission capacity is measured between the 11 planning regions shown in Figure 1. For this plot, the IRA tax credit phaseout is assumed to begin in 2032 for all scenarios (including for current policies) to facilitate comparison across scenarios while keeping policy assumptions constant.

Installed wind and solar capacity also scales with demand growth in the accelerated transmission frameworks (Figure 12). In the 90% by 2035 scenarios, 2050 wind capacity grows to 6–7 times its 2020 capacity with low demand, 9–10 times with mid demand, and 12–13 times with high demand; PV capacity grows to 13–14 times, 15 times, and 18–19 times, respectively. Nuclear capacity grows appreciably only in the Limited transmission framework with mid/high demand and either 90% by 2035 or 100% by 2035 emissions constraints, where it grows to ~2 times 2020 capacity under mid demand and ~4 times under high demand (compared to ≤3% growth in all other transmission frameworks and demand/emissions assumptions).

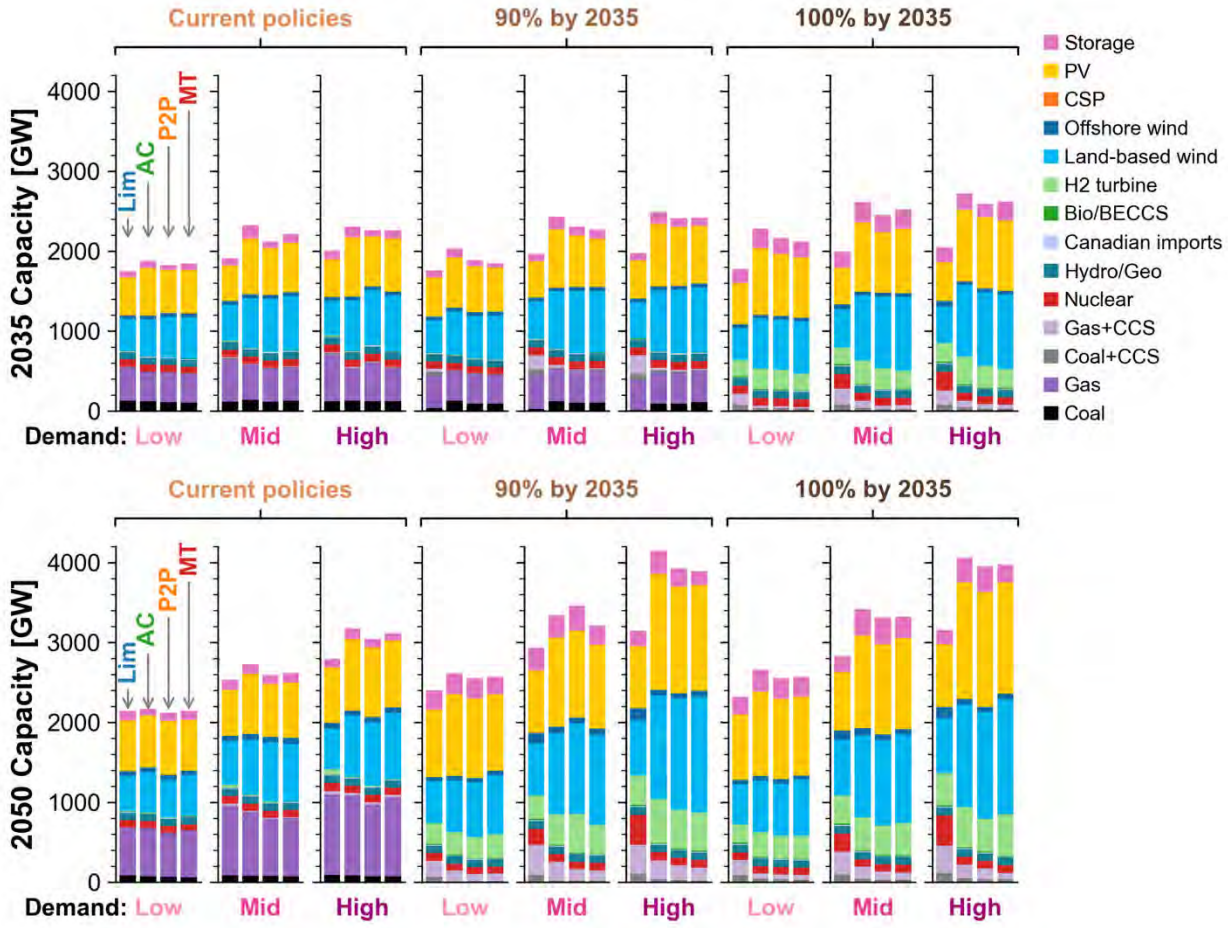


Figure 12. Generation capacity in 2035 and 2050 as a function of demand, emissions constraint, and transmission framework

3.2.2 Benefits from large-scale transmission expansion include hundreds of billions of dollars in system cost savings under decarbonization futures

Though accelerating transmission expansion leads to reductions in CO_2 emissions under current policies, with national emissions limits that fully eliminate grid emissions, the primary impact of accelerated transmission expansion is a reduction in electricity system costs. The main cost metric is the net present value (NPV) of total electricity system costs through 2050, including fixed and operating costs and tax incentives for electricity producers.[31] Figure 13 shows this metric across the 90% by 2035 and 100% by 2035 emissions assumptions (rows), three demand trajectories (columns), and four transmission frameworks (bars). Accelerating transmission expansion reduces costs by $270–490 billion under Mid-Demand/90% by 2035 assumptions, with the AC framework at the bottom of the range of savings and MT at the top (a 4%–8% reduction compared to the $6,370 billion NPV of system costs in the Limited framework).

[31] Unless otherwise noted, the NPV costs are for all expenditures from 2022 to 2050 using a 1.7% societal real discount rate (OMB 2023).

Savings from accelerated transmission increase when decarbonization is achieved more quickly (to $570–810 billion under Mid-Demand/100% by 2035 assumptions) and when demand growth increases (to $710–970 billion in High demand/90% by 2035 and to $860–1,220 billion in High demand/100% by 2035).

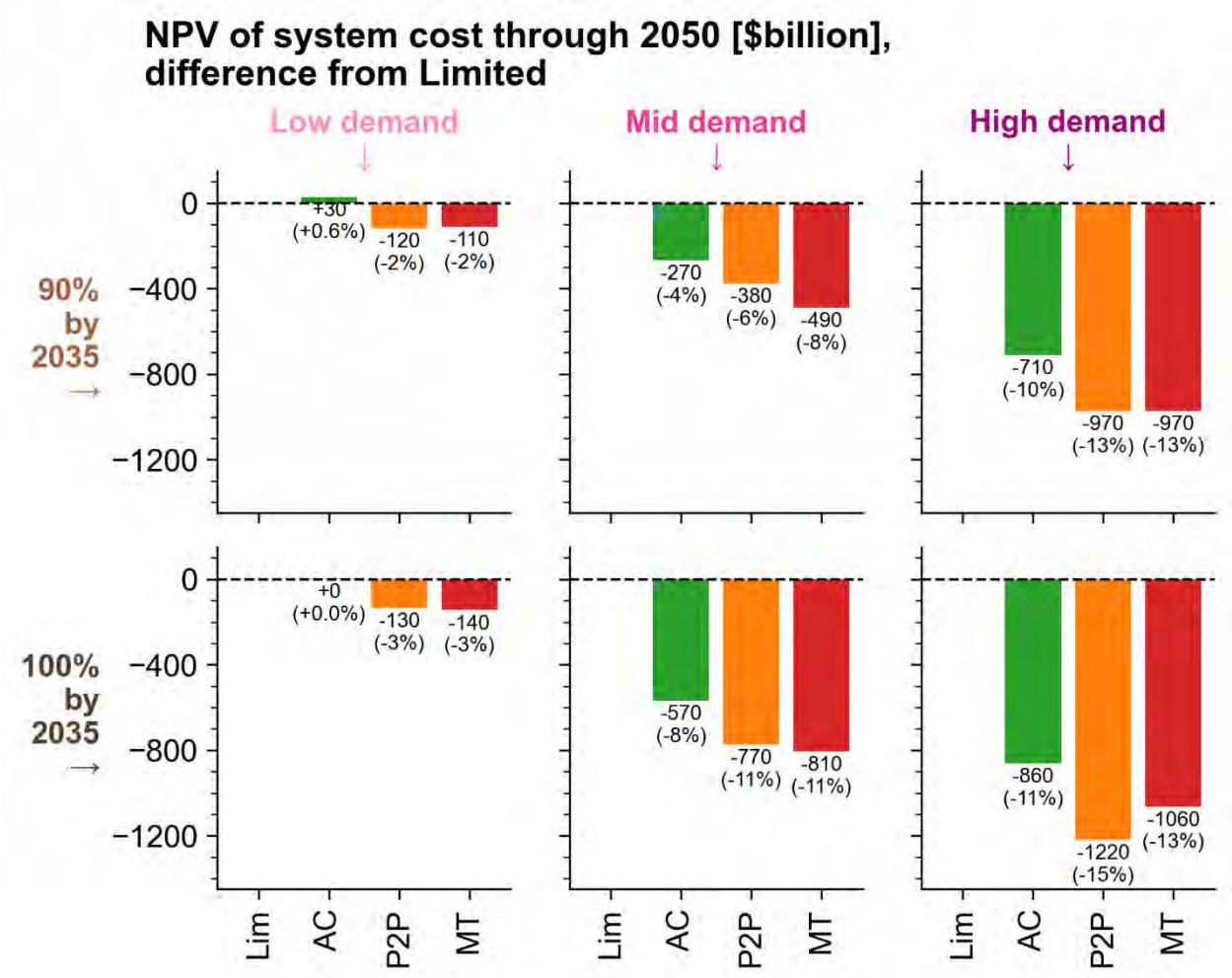


Figure 13. Net present value of total system cost through 2050 expressed as savings relative to the Limited framework

The cost change in each of the three accelerated transmission frameworks relative to the Limited framework is given in $billion and as a percent change below each bar. Differences below ~1% (~$50 billion) are considered within the model uncertainty bounds resulting from imperfect foresight and scenario-specific stress periods.

3.3 Central Demand and Emissions Assumptions

Sections 3.1 and 3.2 show results across all core scenarios, which cover a range of emissions reductions and demand growth assumptions. This section presents findings from the central demand and emissions constraint scenarios, which assume Mid-Demand growth trajectories and 90% emissions reductions by 2035 (100% by 2045). These central scenarios include both the core and the 15 sensitivity cases (Table 1).

3.3.1 Accelerating transmission deployment consistently reduces system cost across a spectrum of sensitivity cases

Across all modeled sensitivity cases, the system cost of a given case is uniformly lower in the three accelerated transmission frameworks than in the Limited transmission framework (Figure 14, Figure 15, and Figure 16), and transmission expansion consistently delivers hundreds of billions of dollars of savings. The core scenario savings of $270–490 billion are on the low end of the modeled sensitivity cases (Figure 16): The range of savings across all sensitivity cases is $270–760 billion for the AC framework; $380–1,170 billion for P2P; and $350–1,170 billion for MT.

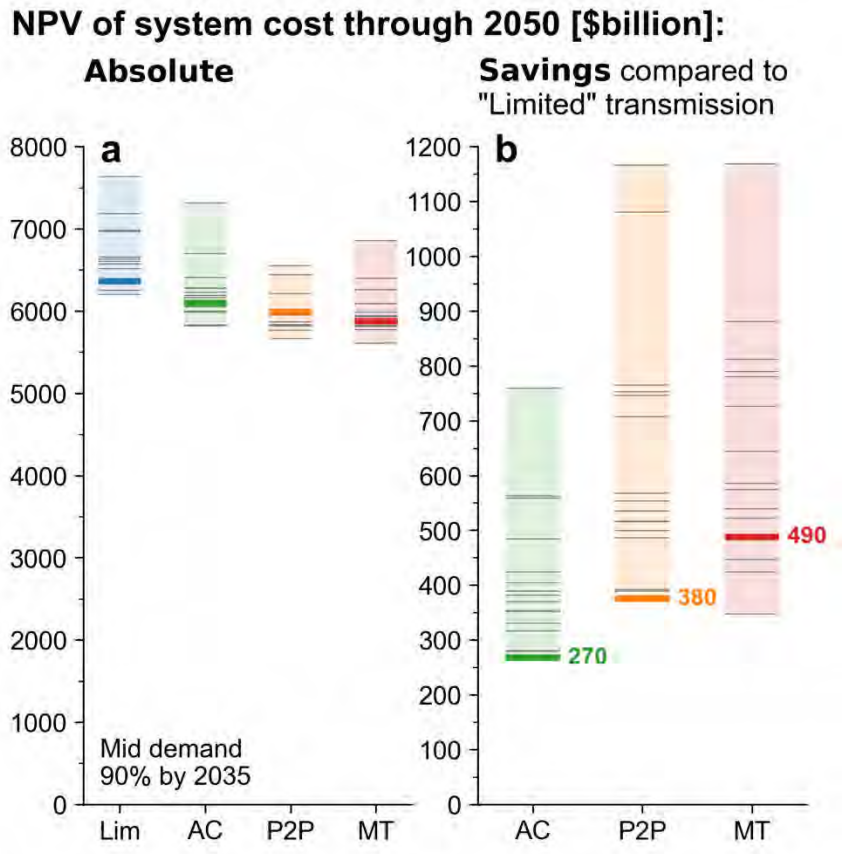


Figure 14. Net present value of total system cost through 2050 under central (Mid-Demand 90% by 2035) assumptions expressed in absolute terms (a) and as savings relative to the Limited framework (b)

Note the change in y-axis scale between panels (a) and (b). Bold line indicates the core scenario result.

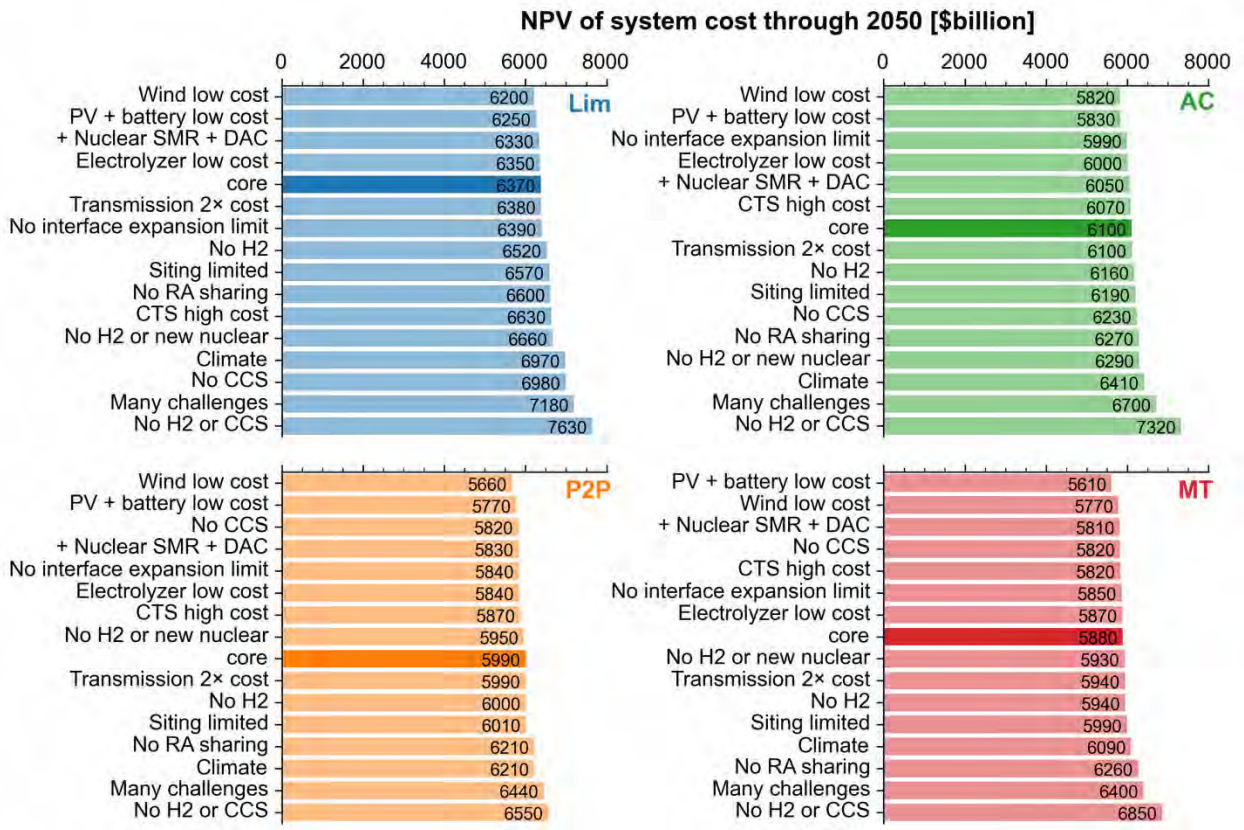


Figure 15. Net present value of total system cost through 2050 for each transmission framework and sensitivity case under Mid-Demand 90% by 2035 assumptions

The savings in each of the three accelerated transmission frameworks relative to the Limited framework are given as numbers in billions of dollars at the right of each bar. Scenarios within each transmission framework are sorted by absolute system cost.

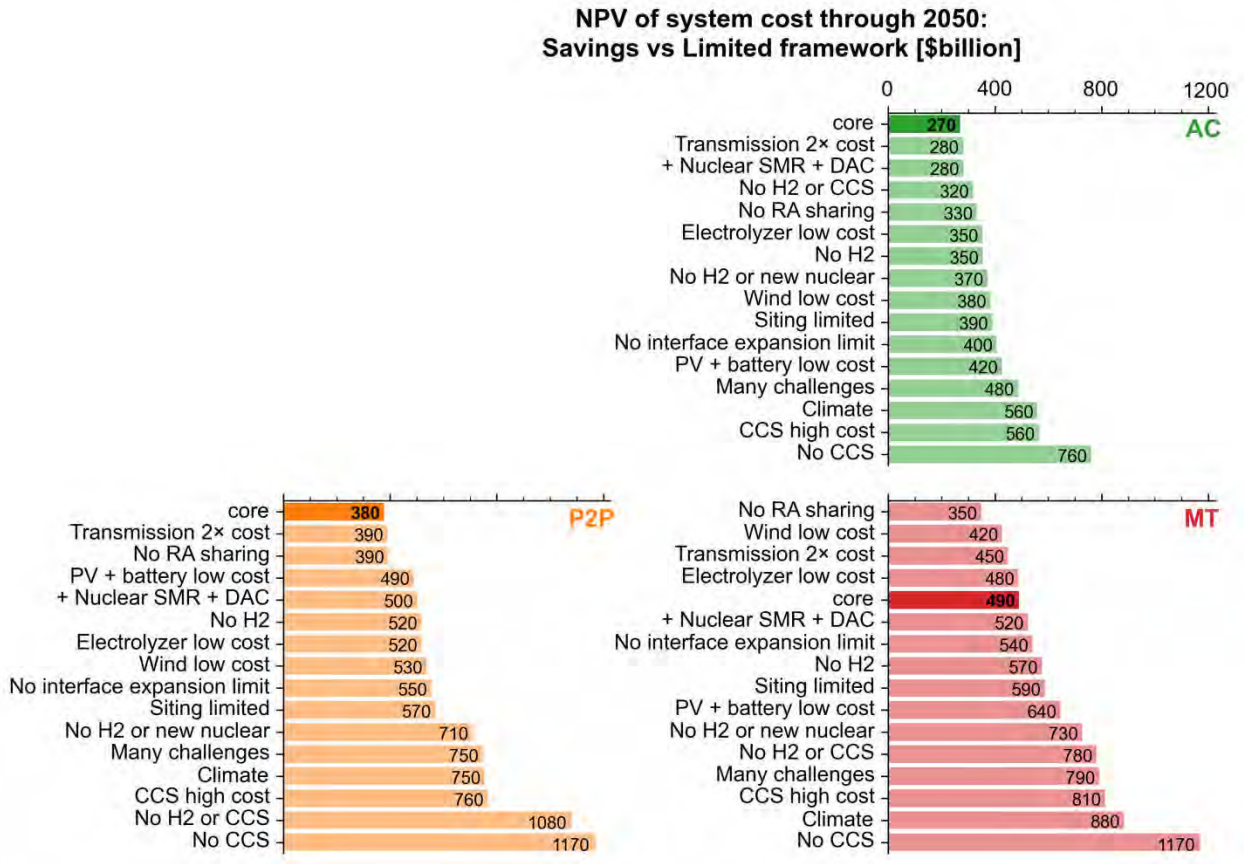


Figure 16. Net present value of total system cost savings relative to the Limited framework under Mid-Demand 90% by 2035 assumptions

Scenarios within each transmission framework are sorted by system cost savings relative to the Limited framework.

Savings from accelerated transmission are largest in futures where alternative technologies are constrained or more expensive. The highest savings from accelerated transmission are in the "No CCS" sensitivity case: Without CCS, costs rise by ~$600 billion in the Limited framework but are relatively unaffected in the other frameworks, leading to savings of ~$800–1,200 billion from accelerated transmission when CCS is unavailable. Transmission-induced savings also increase in the "No H_2" and "No H_2 or new nuclear" sensitivity cases. Transmission expansion could help hedge against the possibility that new low-carbon technologies face difficulties in scaling up from their currently low annual deployment rates. Conversely, if these low-carbon generation technologies become commercially available—as assumed under the core scenarios—the benefits of accelerated transmission expansion are lower but still substantial as discussed previously. Savings from accelerated transmission expansion are also $100–190 billion higher in the "Siting limited" case than in the core scenario, $220–370 billion higher in the "Many challenges" case, and $290–390 billion higher in the "Climate" case. Notably, cost savings from accelerated transmission expansion under the "Transmission 2× cost" case ($280–450 billion) are similar to savings under the core scenario.

Lower system costs in the accelerated transmission frameworks significantly outweigh the costs of new transmission

Across all accelerated transmission frameworks and sensitivity cases, the system cost savings exceed the additional cost of building the transmission compared to the Limited scenario. Figure 17 shows the range of benefit-to-cost ratios for the portfolio of transmission investments in the AC, P2P, and MT scenarios for the 90% by 2035 emissions constraint scenarios.[32] The highest benefit-to-cost ratios are achieved in the P2P and MT scenarios that allow for HVDC transmission development. The core P2P and MT scenarios achieve a benefit-to-cost ratio of 1.7 and 1.8, respectively, compared to the core AC scenario benefit-to-cost ratio of 1.6. As with system cost savings, the benefit-to-cost ratios for the core scenarios are toward the lower end of the ranges. Many sensitivity cases have benefit-to-cost ratios close to 2. Sensitivity cases where new low-carbon technologies are not available typically have higher benefit-to-cost ratios (1.9 to 2.3). The benefit-to-cost ratio exceeds 1.5 across all sensitivity cases; for context, the maximum threshold allowed in FERC Order No. 1000 to determine whether transmission facilities have significant enough benefits to be selected in a regional transmission plan for the purpose of cost allocation is 1.25 (Federal Energy Regulatory Commission 2011).[33]

[32] Benefits are defined as the difference in total nontransmission system costs including generation and storage capital and operating costs and policy incentives between the accelerated transmission framework (AC, P2P, or MT) and the Limited framework. Costs are defined as the NPV of transmission capital and operating costs for all transmission types including spurline, intra- and interzonal lines, and converter stations. More information on the cost analysis is provided in Appendix E.

[33] FERC Order No. 1000 specifies that a benefit-to-cost ratio of 1.25 is the maximum threshold for determining if transmission facilities have sufficient net benefits to be included in regional transmission plans.

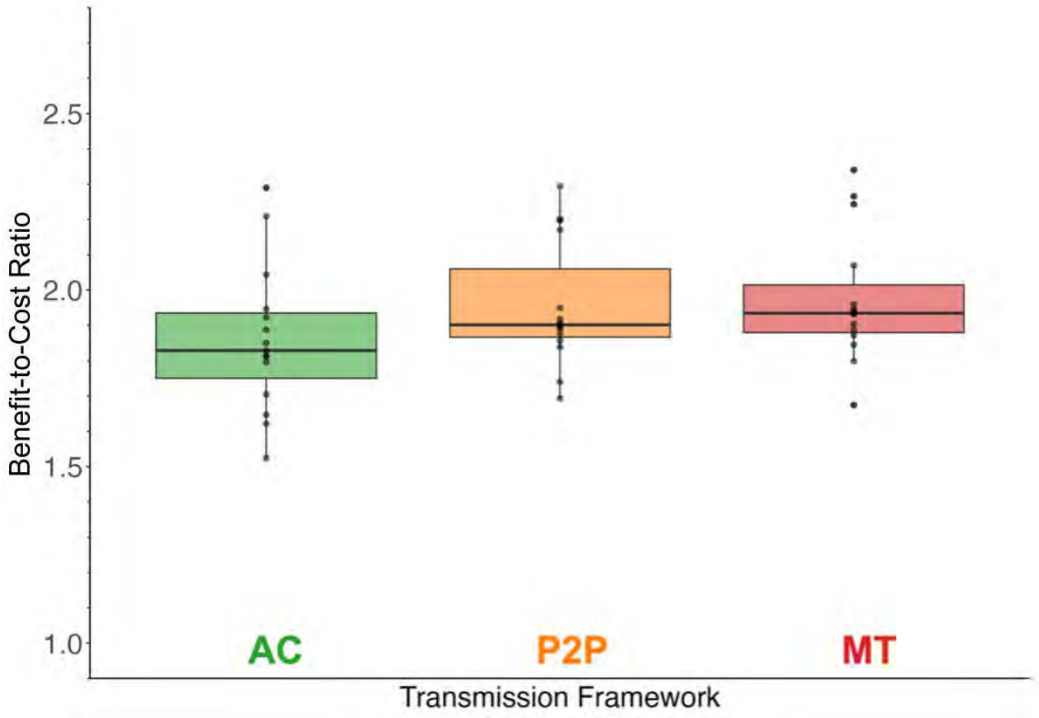


Figure 17. Benefit-to-cost ratio of systemwide savings compared to additional transmission costs relative to the Limited framework under Mid-Demand 90% by 2035 assumptions

The center line indicates the median value, and upper and lower box lines indicate the 25th and 75th percentiles, respectively. The benefit-to-cost ratios exclude the added cost of transmission when calculating benefits.

Transmission expansion helps reduce capital, operating, and fuel expenditures for generation and storage

Historically, savings in production costs have been the primary metric for valuing transmission investments (Chang, Pfeifenberger, and Hagerty 2013; Federal Energy Regulatory Commission 2022). However, transmission development can—positively and negatively—impact a broader range of system costs, including capital investments, fixed operation and maintenance (O&M) costs, and the ability to capture policy incentives. The impact on system costs may change over time as the underlying generation mix changes. Figure 18 shows the change in different types of system costs for the AC, P2P, and MT scenarios compared to the Limited framework from 2025 through 2050.

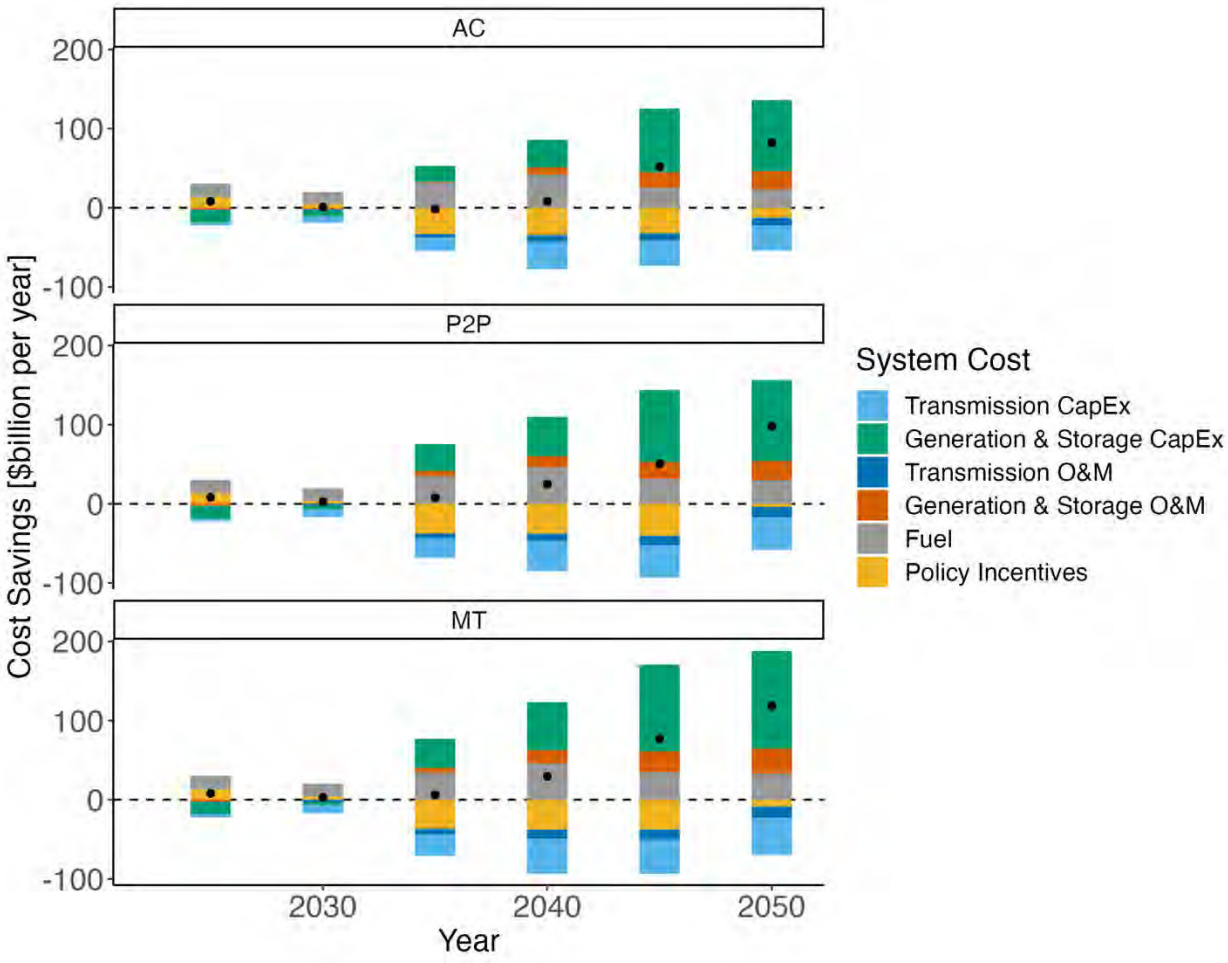


Figure 18. Source of cost savings (real $billion per year) compared to the Limited framework under Mid-Demand 90% by 2035 assumptions

Negative values indicate greater costs compared to the Limited framework; positive values represent savings. Black dots indicate net savings across all system cost categories.

Savings in generation and storage capital costs are the largest source of system savings, totaling $420 billion in the AC framework and more than $700 billion in the MT framework (present value), equivalent to an 11%–20% reduction in total generation and storage capital costs. These savings do not begin until after 2030 and increase in magnitude over the planning period. Reductions in fuel costs make up the second largest source of savings because increased investments in transmission enable greater use of VRE resources, resulting in a 44%–49% decrease in fuel expenditures. Annual savings from avoided fuel costs peak around 2040 and start to decline as the share of VRE increases and opportunities to displace fuel generation are reduced.

Though total system costs decrease in the accelerated transmission development scenarios, capital and operating costs for transmission increase compared to the Limited framework as investments in all types of transmission increase. Total expenditures for transmission (present value) are $760 billion; $1,220 billion; $1,320 billion; and $1,390 billion for the Limited, AC, P2P, and MT frameworks, respectively

(Figure 19). Investments and operating costs for local transmission infrastructure make up the largest share of transmission costs, accounting for more than 40% of total transmission expenditures for all transmission frameworks. Investments in interregional transmission are smaller in all scenarios but grow noticeably after 2030 in the accelerated transmission frameworks (AC, P2P, MT) and reach $12 billion per year by 2050. For context, recent historical transmission investments are estimated to be $20–25 billion per year (Edison Electric Institute 2024).[34] Annual fixed O&M costs for transmission infrastructure—assumed to be 1.5% of the upfront capital cost—make up a significant share of total expenditures, accounting for 50% of total transmission expenditures in 2025, falling to 30% by 2050. Increased transmission development also impacts the tax credit outlay, particularly including the production and investment tax credits for wind, solar, and storage as well as the CO_2 capture tax credit.[35]

[34] The scope of Edison Electric Institute's estimates may not align with the transmission cost categories. In particular, spur lines and other interconnection investments modeling may not be included in the historical data.

[35] The system cost metric and associated benefit-cost-ratio method includes the value of tax credits (tax credits are treated as negative costs to the electricity system) because this metric is intended to measure the impact from the perspective of the electricity system, including producers. This electric sector perspective differs from an economywide perspective where tax credits are typically viewed as transfers between taxpayers and those receiving the credits. When tax credits are excluded in the cost metrics to be more aligned with this perspective, the system cost savings from accelerated transmission change to $570–830 billion (compared with $270–490 billion) under the core scenarios and the benefit-cost ratios change to 2.2–2.3 (compared with 1.6–1.8).

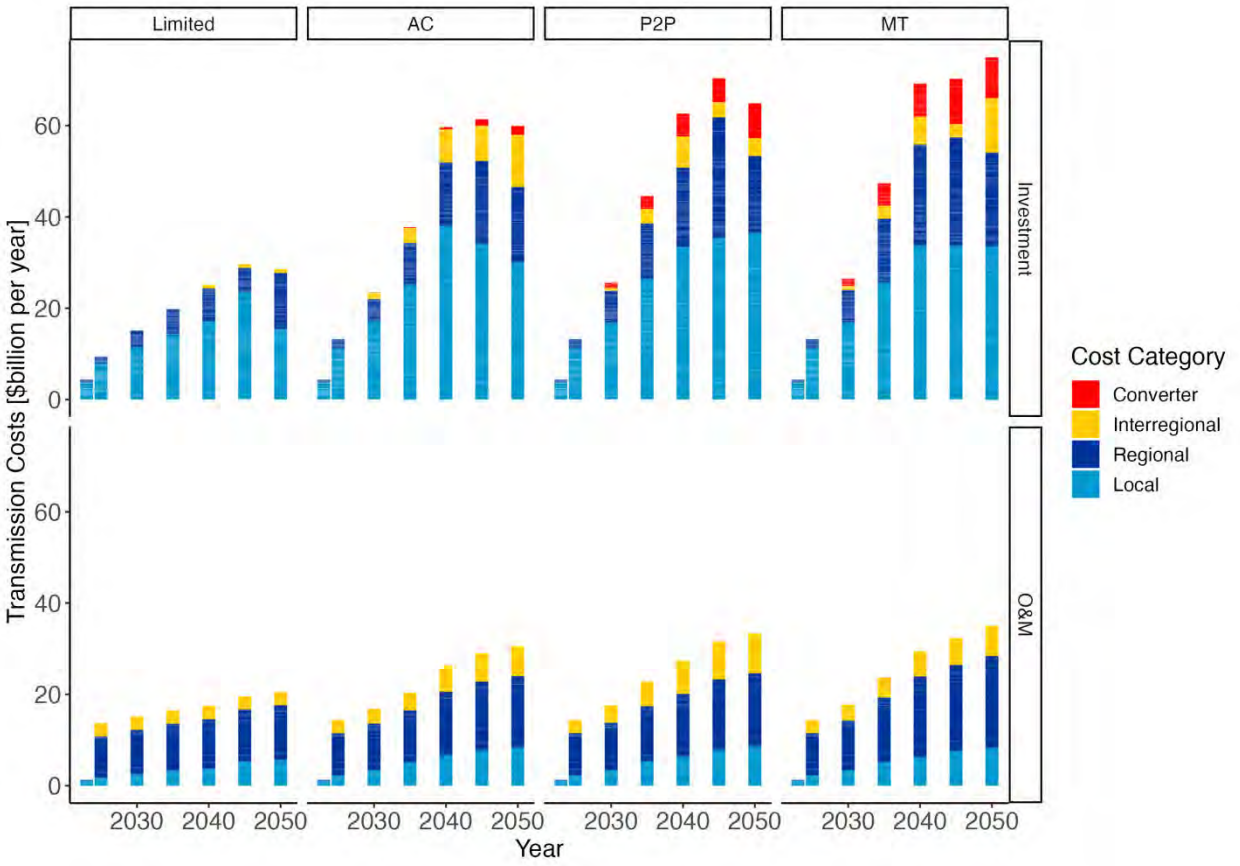


Figure 19. Transmission costs under Mid-Demand 90% by 2035 assumptions

Investments in converters serve both regional and interregional transmission needs.

Interregional transmission enables cost savings for most regions

Though the systemwide value and benefit-cost ratio of each accelerated transmission framework are high, they are not uniform across all individual transmission planning regions. When evaluating the benefit distribution among regions, further consideration of where power is exported and imported—and the value of the power traded—is needed to capture the transmission benefits of interregional trade to each region. To disaggregate benefits regionally, operational costs are adjusted to approximate how these costs might be allocated between importing and exporting regions. To do so, the analysis uses the adjusted production cost (APC) metric.[36] This metric is the difference in total production costs adjusted for import costs and export revenues with and without a proposed transmission investment. For this study, the APC is based on zonal marginal prices from the capacity expansion model. Further study with full 8,760 hourly resolution at a nodal resolution can be used to refine the estimated adjusted production costs for each region. The following figures show the total savings to each region

[36] See Appendix E for more details on the APC method used in current planning processes and the adjustment values calculated for the core transmission scenarios.

compared to the Limited scenario by system cost category (Figure 20a) and as a share of each region's costs (Figure 20b).

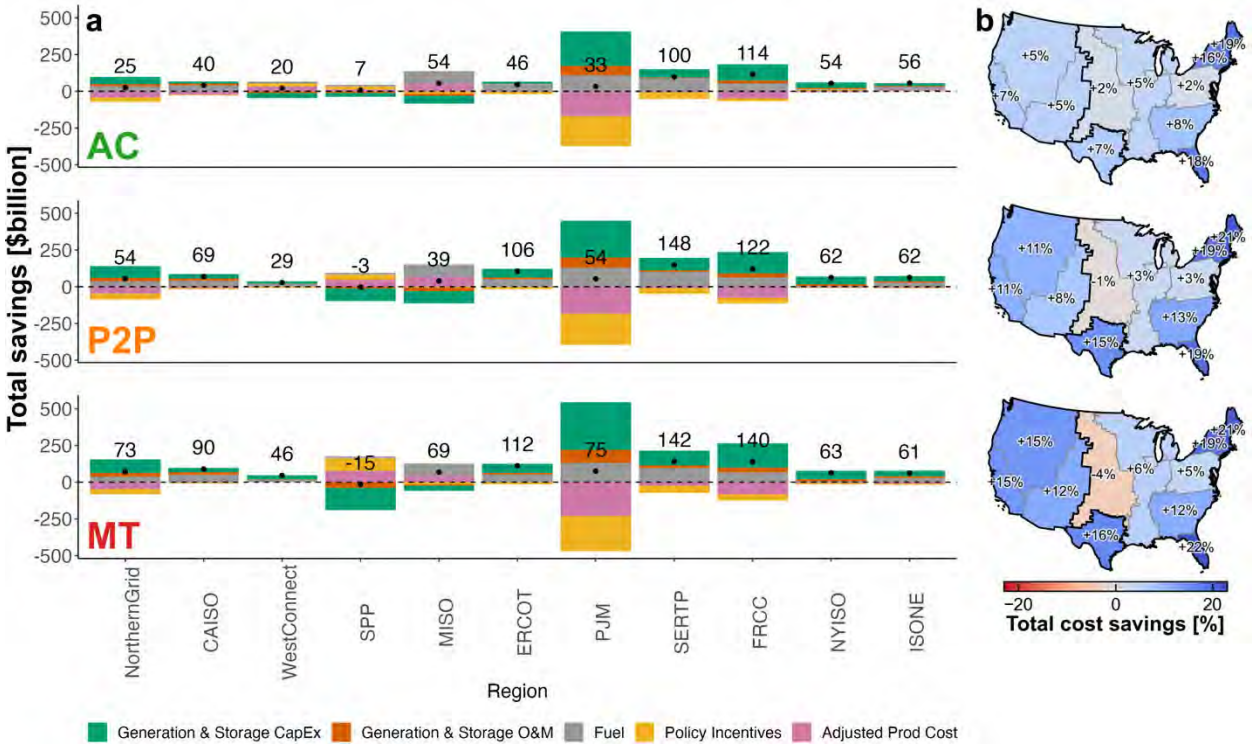


Figure 20. Net present value of system savings by region in absolute $billion (a) and percentage (b) of avoided costs relative to the Limited framework under Mid-Demand 90% by 2035 assumptions

Black dots in (a) indicate net savings across all system cost categories. These results show the disaggregation of system benefits evaluated as part of this study and are not intended to prescribe any specific cost allocation among planning regions.

Among planning regions, savings from increased transmission interconnection in 90% by 2035 Mid-Demand scenarios are highest in the Southeast (SERTP, FRCC) and Texas (ERCOT). These regions see large decreases in fuel costs and generation and storage capital costs because the transmission network allows them to make greater use of lower-cost resources located in other regions. As a share of total costs, ISONE, FRCC, and NYISO see the highest savings, with costs declining by more than 20% in the MT framework. In other regions, such as SPP, total costs increase in some scenarios compared to the Limited framework because these regions are building more generation capacity to export to neighboring regions. In these regions, the additional benefits from collecting more investment and production tax credits and increased generation revenues from selling power to neighbors do not outweigh the additional cost of building and operating more generation capacity.

Similar to systemwide cost savings, the regional transmission value—measured by the savings in investment and operating costs transmission can provide—is sensitive to technology availability and costs, climate impacts, siting constraints, and other varying system characteristics. Figure 21 shows the range of transmission values by region across all sensitivity cases using the Mid-Demand 90% by 2035 assumptions.

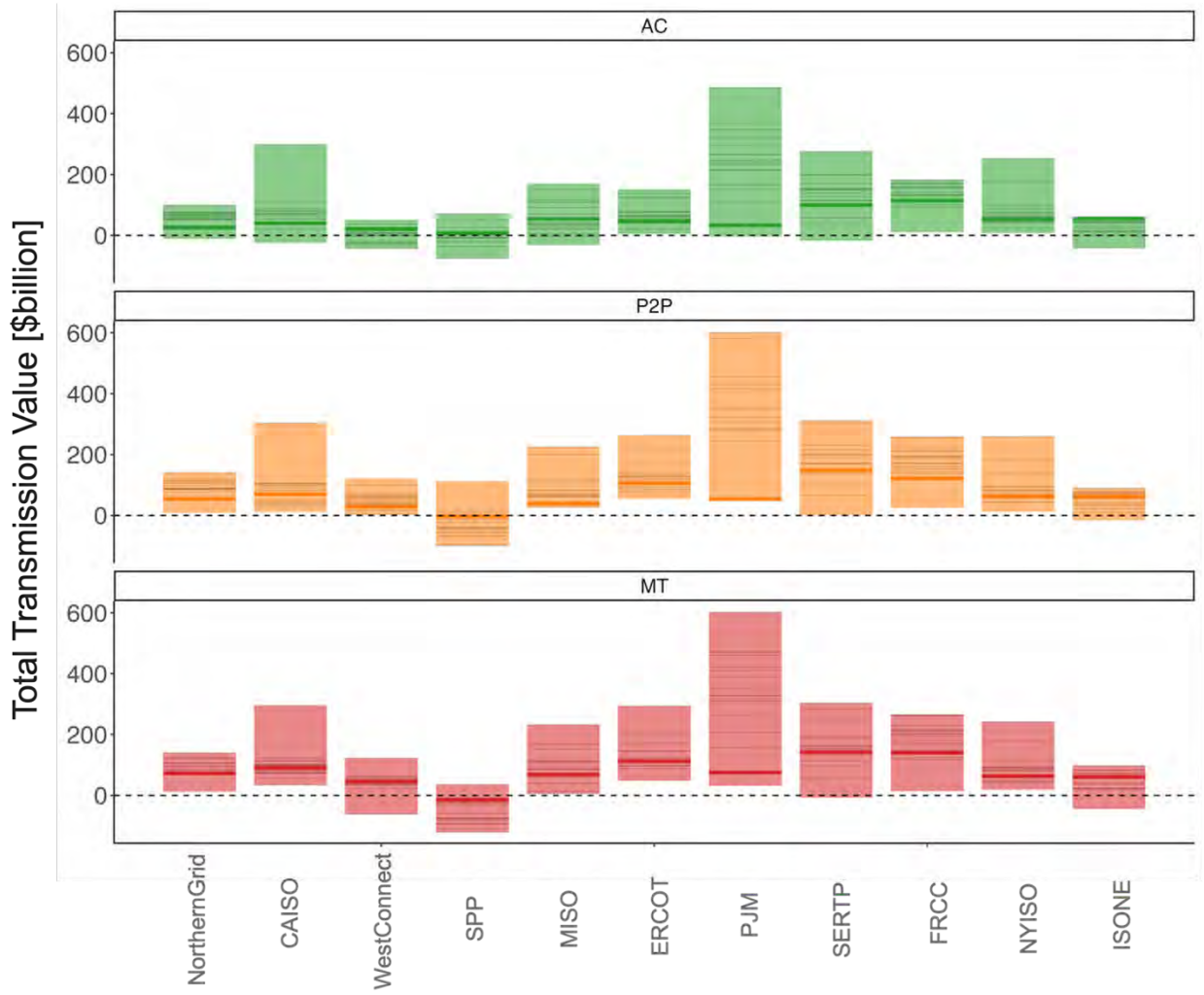


Figure 21. Net present value of total system cost savings to each transmission planning region relative to the Limited framework under Mid-Demand 90% by 2035 assumptions

Bold line indicates the core scenario result.

The impact of each sensitivity varies by region. For example, in regions that rely on CCS and H_2 technologies to achieve emissions reductions targets, the value of transmission increases when these technologies are not available. Detailed results for each modeled sensitivity are presented in Appendix D.4.

3.3.2 Transmission expansion enables increased access to wind and solar

As in the Current Policies scenarios (Section 3.1), accelerating transmission expansion increases the share of VRE in the resource mix across all sensitivity cases (Figure 22). The VRE share (annual solar and wind generation divided by total annual generation from all sources) is ~20% higher in the AC, P2P, and MT core scenarios (77%–82% VRE share) than in the Limited core scenario (58% VRE share).

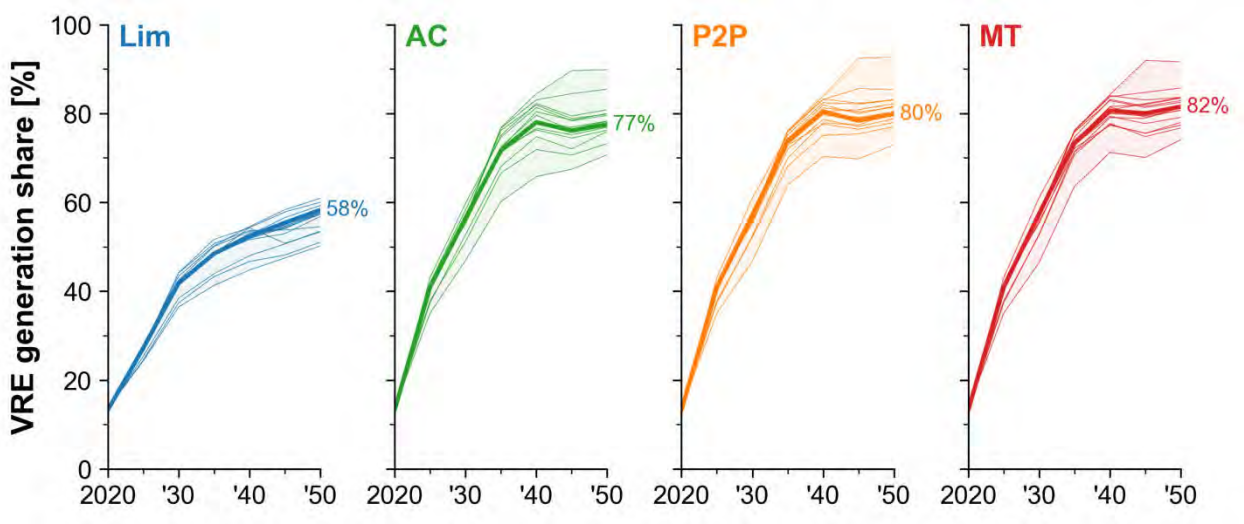


Figure 22. VRE share of total generation for the Mid-Demand 90% by 2035 scenarios for each transmission framework

Core scenarios are shown by a thick line, with the 2050 value labeled; sensitivity cases are shown by thin lines, with the shaded area showing the range between sensitivity cases.

There is considerable spread in 2050 VRE share across sensitivity cases for a given transmission framework, but the sizable increase in VRE through accelerated transmission is consistently observed across all sensitivity cases. The 2050 VRE share in the Limited framework ranges from 50% to 61% across sensitivity cases, versus 71%–90% in the AC framework, 73%–93% in P2P, and 74%–92% in MT. Excluding the "No CCS," "No H_2 or CCS," "No H_2," and "No H_2 or new nuclear" sensitivity cases, the nuclear generation share ranges from 16% to 27% in the Limited framework and 6% to 9% in the accelerated transmission frameworks. The generation share from fossil generation with CCS ranges from 12% to 18% in the Limited framework and 2% to 11% in the accelerated transmission frameworks. Figure 23 shows the 2050 generation mix for all sensitivity cases. The capacity mix for all sensitivity cases is shown in a similar format in Figure D-10.

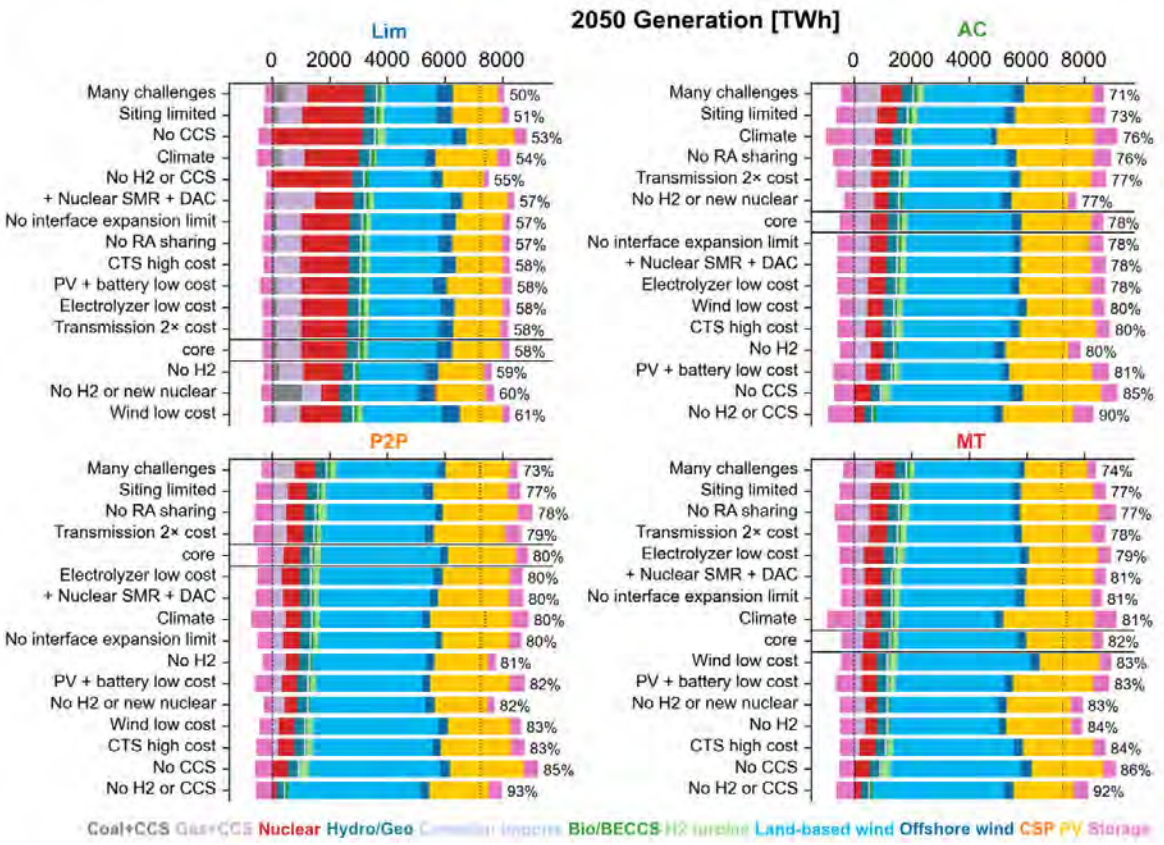


Figure 23. National generation mix in 2050 for the Mid-Demand 90% by 2035 scenarios for each transmission framework and sensitivity case

Within each transmission framework, the sensitivity cases are sorted by 2050 VRE share (indicated by the percentage value to the right of each generation bar). Total generation is greater than end-use demand (vertical dotted line) because of transmission and distribution losses, storage losses, and generation for hydrogen production via electrolyzers. Total storage charging is shown as negative values and discharging as positive values.

3.3.3 Significant amounts of transmission are added at all scales (local, regional, and interregional) in decarbonized systems

When transmission additions are limited, local generator interconnection takes precedence over longer-distance transmission

Both long-distance and local transmission expansion play large roles in the lowest-cost decarbonized power systems (Figure 24). But in the Limited transmission framework, where annual total transmission additions are limited to 1.83 TW-mile/year, the large majority of the limited “budget” for transmission additions is used for local interconnection of new wind and solar resources in both the core scenarios (Figure 24) and sensitivity cases (Figure 25). Roughly 92% of total transmission additions between 2020 and 2050 in the Limited framework is associated with local interconnection. As the availability of new long-distance transmission increases, this fraction drops—to 56% in the AC framework, 42% in the P2P framework, and 31% in the MT framework—although the absolute amount of new interconnection capacity is greater in the accelerated transmission frameworks (110–120 TW-miles) than in the Limited framework (~50 TW-miles), reflecting the larger renewable energy share in these scenarios.

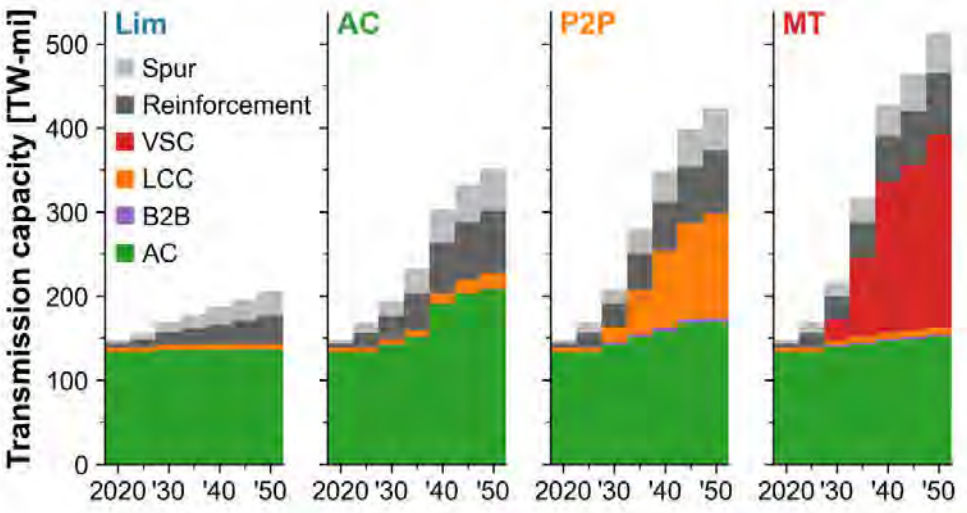


Figure 24. Transmission capacity under Mid-Demand 90% by 2035 assumptions for each transmission framework

Local transmission for wind and solar interconnections includes both spur and reinforcement capacity. Other categories are for interzonal transmission.

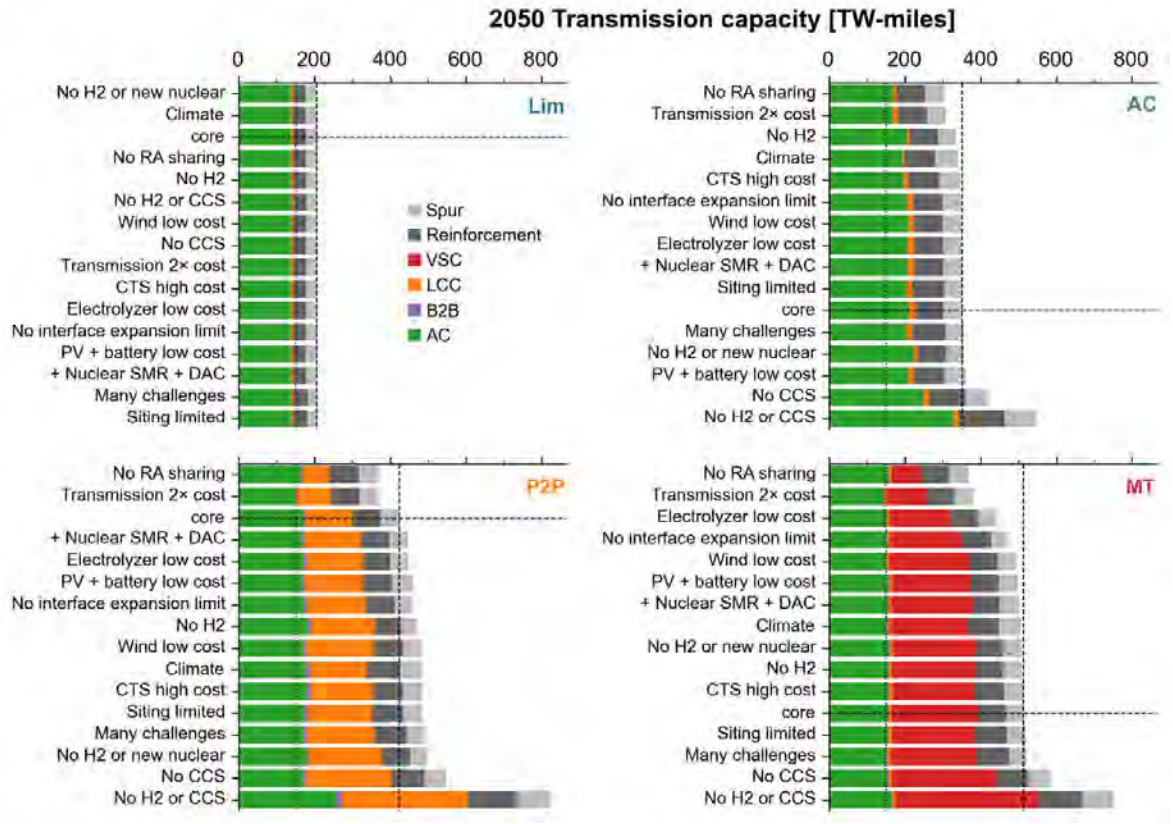


Figure 25. Transmission capacity in 2050 in the Mid-Demand 90% by 2035 scenario for each transmission framework and sensitivity case

Values for the core scenarios for each transmission framework are marked by dashed black lines. Within each transmission framework, sensitivity cases are sorted by total transmission capacity in 2050. The lighter vertical dashed line shows the 2020 capacity (~150 TW-miles). The 1.83-TW-mile/year limit on annual transmission additions is binding in all sensitivity cases for the Limited transmission framework, making 2050 transmission capacity the same in all sensitivity cases for this framework.

If available, HVDC transmission additions outpace AC additions for long-distance transmission

Both AC and HVDC transmission additions are allowed in the P2P and MT frameworks, but HVDC additions significantly outweigh interzonal AC additions in all sensitivity cases in these frameworks (Figure 25). The amount of new HVDC capacity added through 2050 is 2.3–6.0 times the amount of new interzonal AC capacity in the P2P framework and 3.9–16 times in the MT framework. ReEDS does not explicitly model AC power flow or the implications of DC protection on system design; the choice between AC and DC for interzonal transmission investments is thus driven solely by $/MW cost (including the cost of AC/DC converter stations and associated reactive power support) and losses, both of which are lower for DC than AC when distances exceed ~200–500 miles (Alassi et al. 2019).

3.3.4 Expansion of interregional transmission is significant in decarbonized systems

Expansion of long-distance transmission is concentrated in the central part of the country

Previous studies have noted the synergy between transmission and wind deployment (P. R. Brown and Botterud 2021; Denholm et al. 2022); because wind capacity factors exhibit greater spatial variability than solar capacity factors (Figure 26) and because daily solar variability is well-matched with short-duration storage, transmission deployment tends to be correlated with wind deployment and storage deployment tends to be correlated with solar deployment (Blair et al. 2022; Frazier et al. 2021). A similar relationship—that the greatest density of new long-distance (interzonal) transmission additions occurs around the midwestern “wind belt” (Figure 26, Figure 27)—is observed in the scenarios. The trend is most pronounced in the AC transmission framework, where three multilink connections are observed between the wind belt and demand centers in the Southwest, Midwest, and Southeast. A greater amount of long-distance transmission overall is added in the P2P and MT frameworks, but most of the largest links have an endpoint in the wind belt. Though some north-south additions are observed, most new long-distance transmission capacity is oriented predominantly east-west.

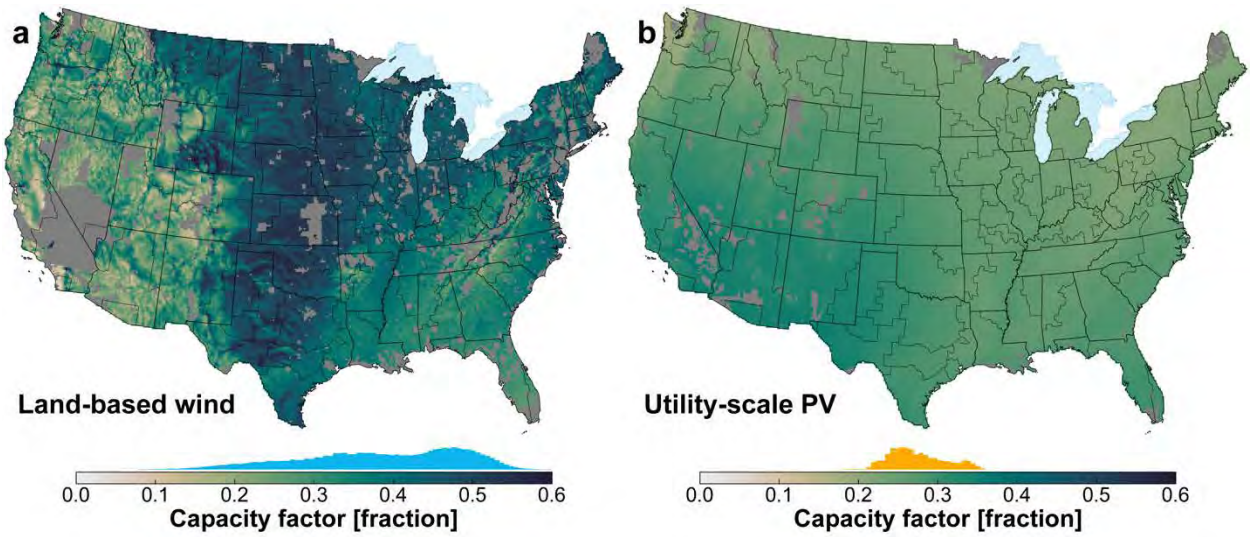


Figure 26. Average capacity factor of land-based wind (a) and utility-scale PV (b) over 2007–2013

Both maps assume Reference Access siting (Appendix A); sites without developable capacity are shown in gray. Both maps show AC capacity factor using the same color scale range. The "wind belt" refers to the darkest-colored (highest-capacity-factor) region in the wind map extending from north to south through the center of the country. Histograms above color bars indicate the frequency of occurrence of the indicated capacity factor values across the ~50,000 reV model sites shown in the corresponding map.

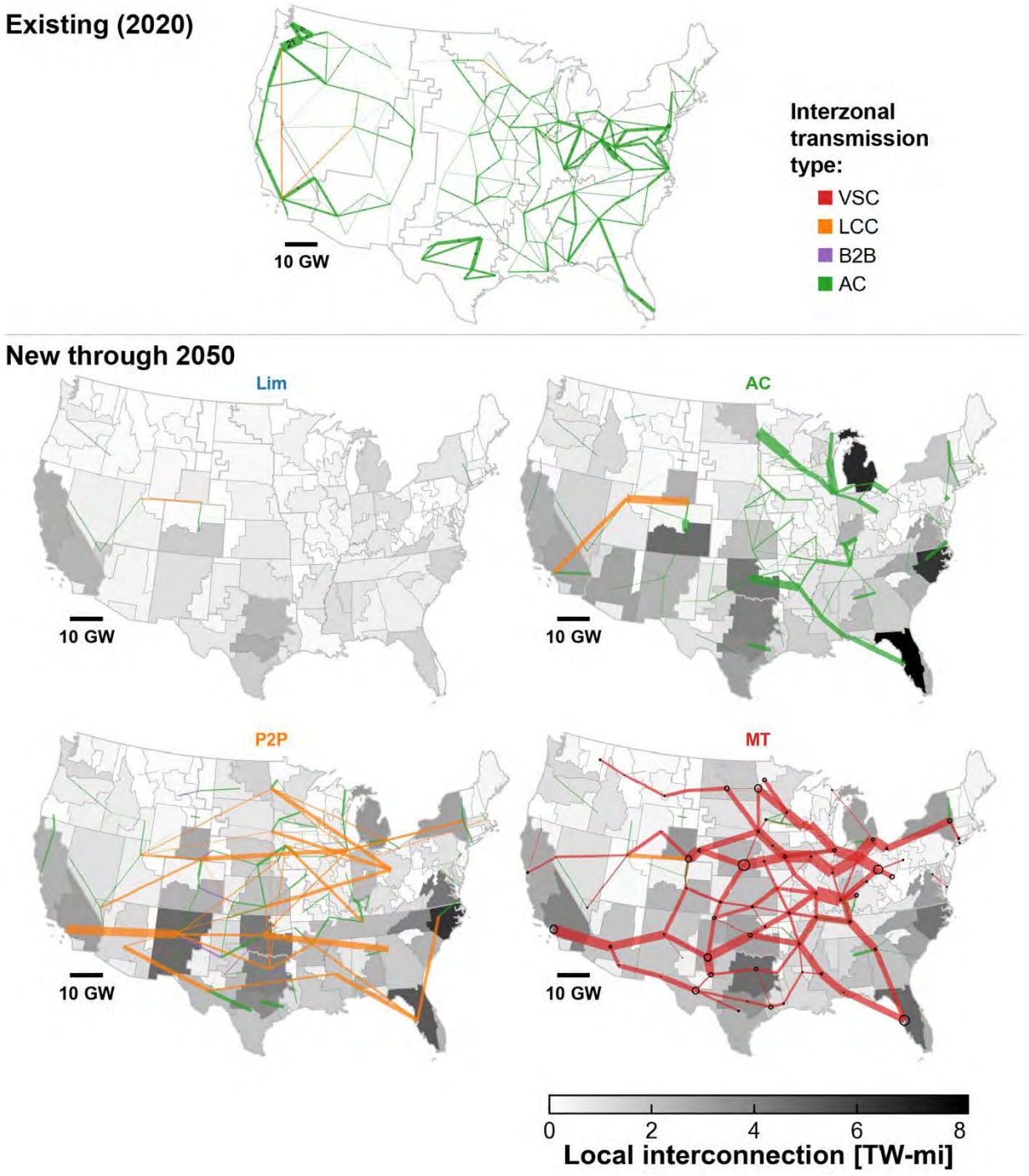


Figure 27. New local and long-distance transmission through 2050 in the Mid-Demand 90% by 2035 scenarios for each transmission framework, with existing 2020 long-distance transmission capacity for context (top)

Interface transfer capability is indicated by the thickness of the lines connecting ReEDS zones. Converter capacity in the MT framework is indicated by the diameter of empty black circles, using the same length scale as the interface lines. The depiction of interzonal transmission capacity as straight lines between zone centers is a visual simplification; in practice, the interzonal transfer capacity would be spread across many transmission corridors for each interface.

The MT scenario tends to make the most efficient use of AC/DC converter capacity. Some zones have minimal converter capacity (indicated by the small black circles in Figure 27), instead acting primarily as pass-throughs in the HVDC network, while exporting zones (in the wind belt) and importing zones (in southwestern and eastern demand centers) install converters sized to their usage needs. The P2P scenario, on the other hand, may make more efficient use of transmission rights-of-way by using higher-voltage (thus higher-power-capacity) LCC architectures (Alassi et al. 2019), although transmission land use is not directly considered here.

Regional transmission trends can be summarized at the planning region level using the ratio of “transfer capability to other planning regions” (GW) to “peak demand within the planning region” (GW) (Figure 28). A range of interregional transfer capabilities is observed in the current (2020) system: ERCOT has a transfer capability ratio of 0.01; ISONE, SERTP, and FRCC range from 0.1 to 0.3, and other regions range from 0.3 to 0.7. In the Limited transmission framework, new additions of interregional transfer capacity are not allowed; thus, as peak demand increases over time, the transfer capability ratio falls. In the AC framework, many regions maintain transfer capability ratios similar to their 2020 values, although there are notable increases in SPP and MISO. The transfer capability ratio increases dramatically for the wind-rich regions of SPP, MISO, and WestConnect in the MT transmission framework, reaching ~2.6 for SPP and ~1.8 for MISO and WestConnect. When interconnection-seam-crossing capacity additions are allowed in the two HVDC scenarios, the transfer capability ratio in ERCOT increases to roughly 0.3, on par with other regions with stronger existing connections to neighboring regions.

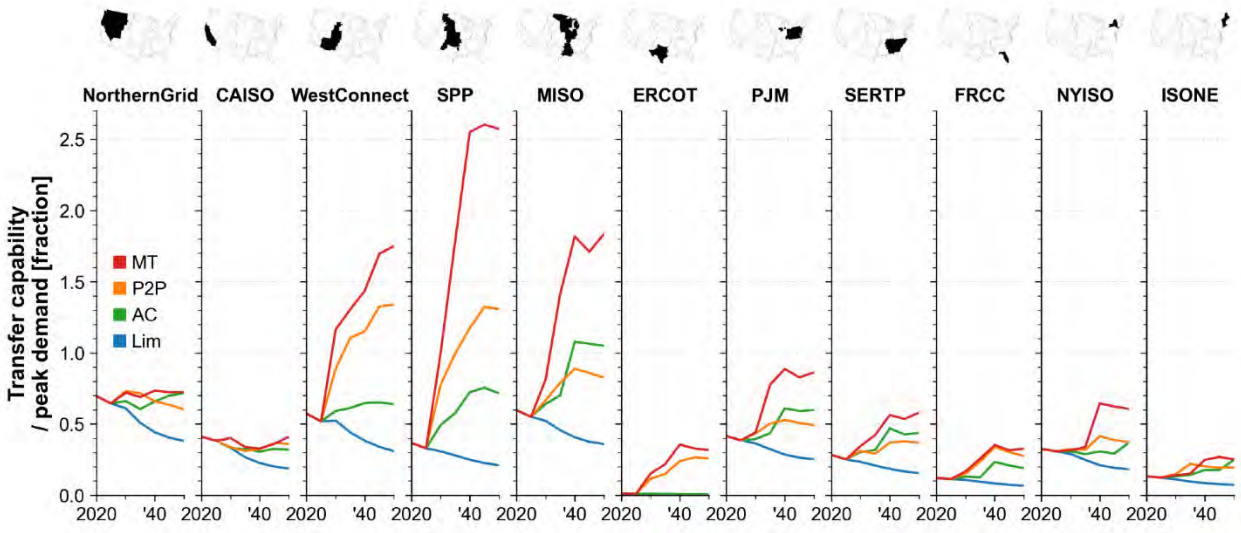


Figure 28. Ratio of interregional transfer capability to peak demand for the 11 planning regions with Mid-Demand 90% by 2035 assumptions across the four transmission frameworks

Interregional transfer capability for a given planning region is defined as the sum of import/export capacity between that planning region and other planning regions.

When allowed, transmission capacity expands significantly across the three interconnection seams

Though many interregional interfaces host large transmission capacity additions in the decarbonization scenarios, the interconnection "seams" demonstrate particularly large capacity additions relative to their currently small transfer capability (Figure 29). New seam-crossing capacity is not allowed in the Limited or AC frameworks but expands to ~80 GW by 2050 in the P2P framework (~37 times the currently installed seam-crossing capacity of 2.1 GW) and ~110 GW (~50 times) in the MT framework. By 2035, the seam-crossing capacity reaches roughly half of its 2050 value: 44 GW in P2P and 52 GW in MT. Transmission capacity is added across each of the three seams in both HVDC frameworks.

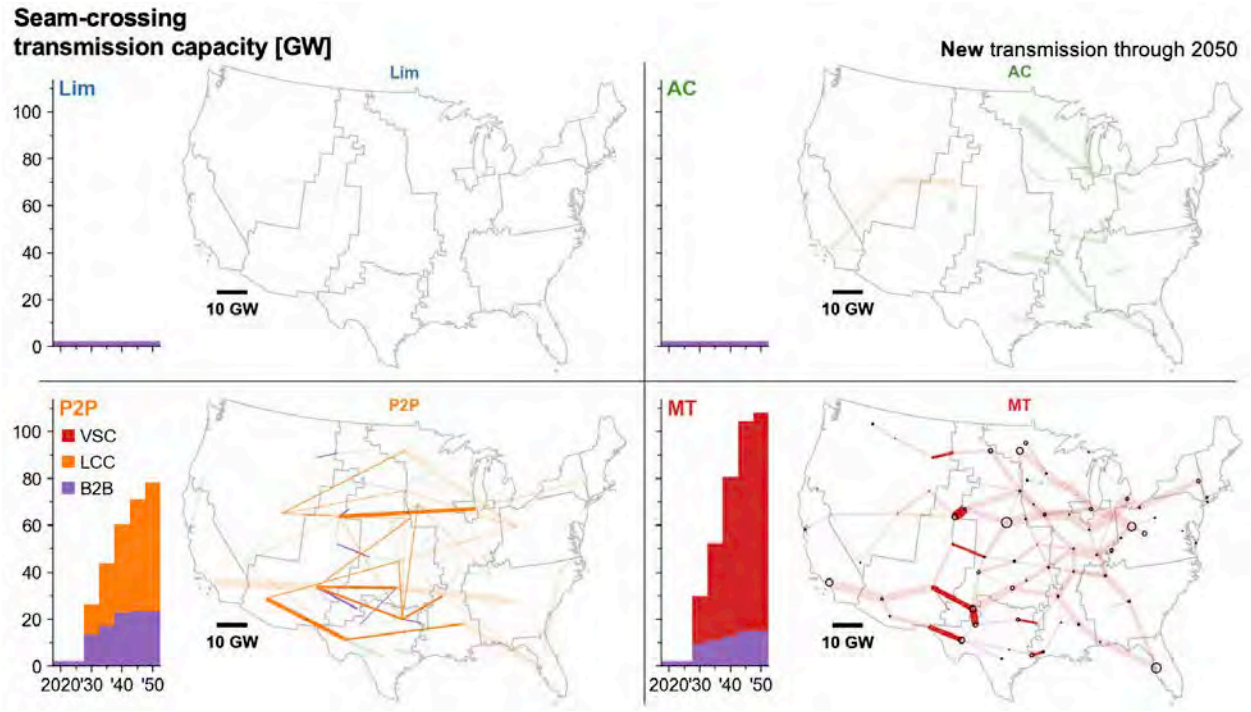


Figure 29. New interconnection-seam-crossing transmission capacity in each of the transmission frameworks with Mid-Demand 90% by 2035 assumptions.

Spatial patterns in transmission expansion are similar across many sensitivity cases

The transmission deployment maps shown thus far have used core scenario assumptions, but there is significant uncertainty in the projected cost and availability of different technologies between now and 2050. It is therefore important to understand whether the spatial trends discussed thus far vary under different assumptions regarding technology evolution, here parameterized through the 15 sensitivity cases described previously. Though the absolute amount of transmission capacity deployed varies substantially across sensitivity cases for a given transmission framework (Figure 25), the spatial distribution of new long-distance transmission is largely consistent (Figure 30, Figure 31, and Figure 32). The greatest density of long-distance transmission additions is observed around the wind belt, and the orientation of new long-distance transmission additions (particularly in the P2P and MT frameworks) is predominantly east-west.

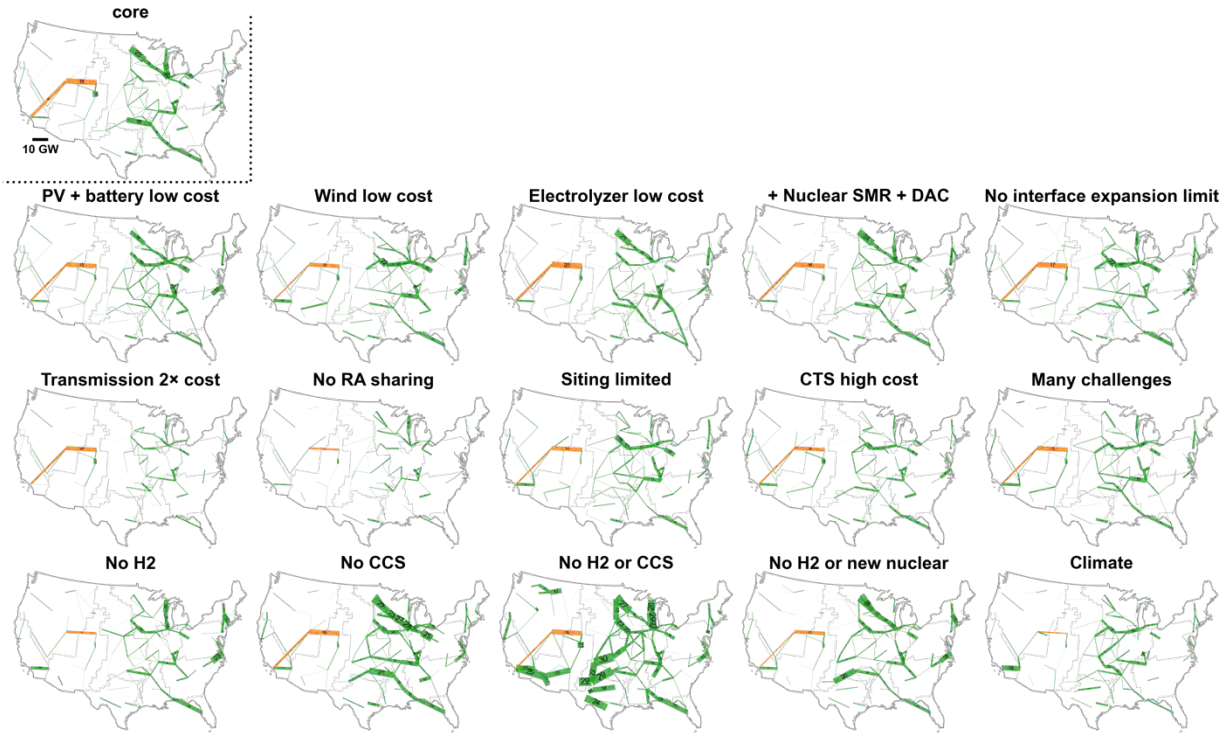


Figure 30. New long-distance transmission additions through 2050 with Mid-Demand 90% by 2035 assumptions for each sensitivity case under the AC transmission framework

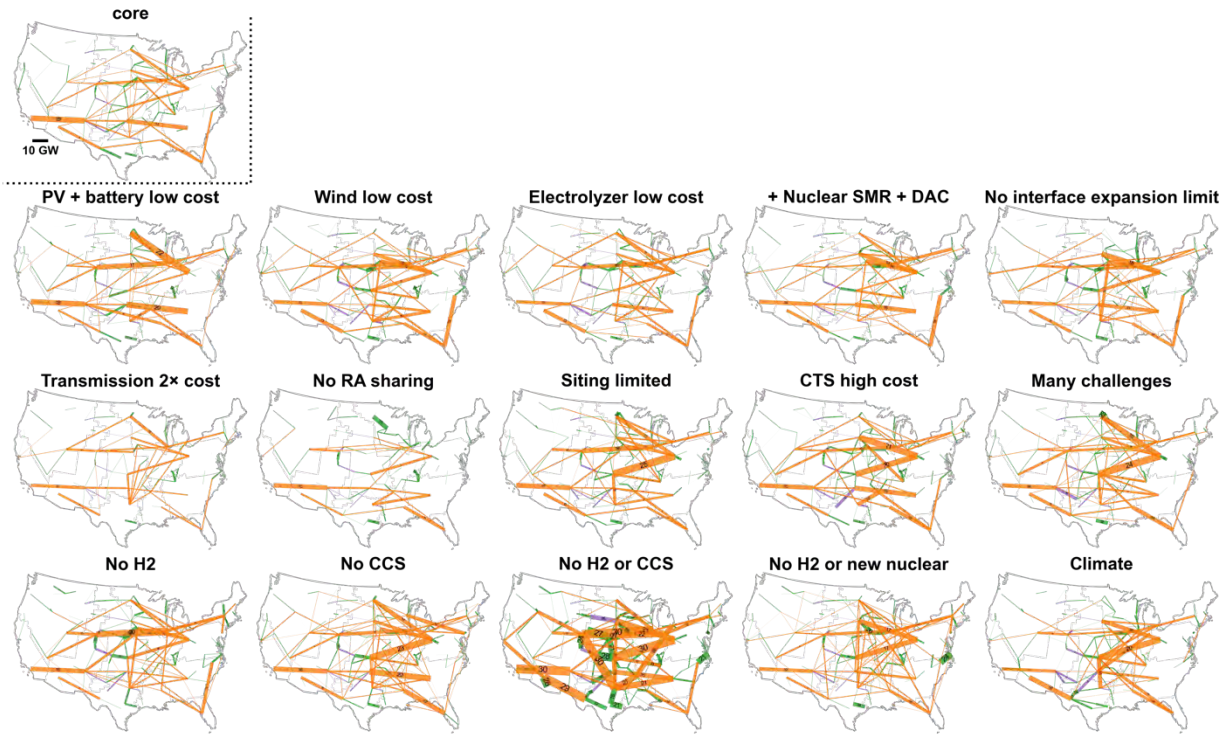


Figure 31. New long-distance transmission additions through 2050 with Mid-Demand 90% by 2035 assumptions for each sensitivity case under the P2P transmission framework

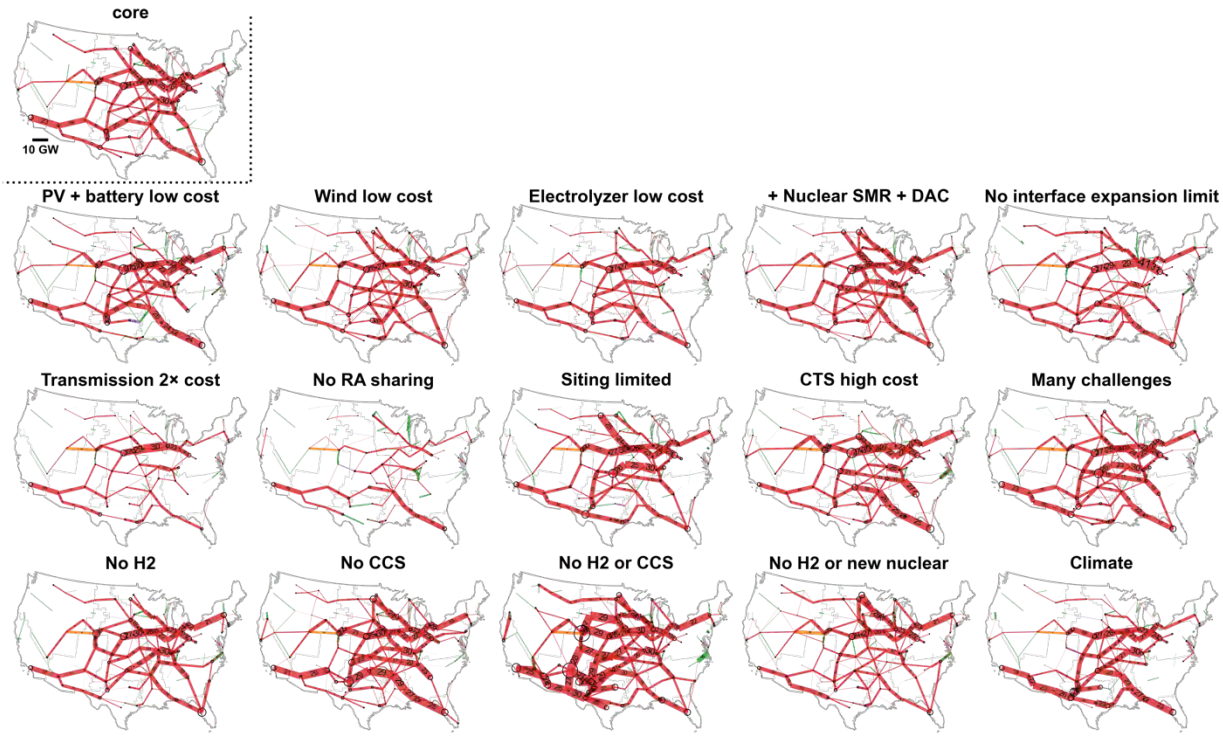


Figure 32. New long-distance transmission additions through 2050 with Mid-Demand 90% by 2035 assumptions for each sensitivity case under the MT transmission framework

Figure 30, Figure 31, and Figure 32 visually demonstrate the similarity in the spatial trends in transmission development across the sensitivity cases modeled. The following text box presents an analysis that more systematically evaluates interregional transmission expansion in these scenarios to identify subregional High Opportunity Transmission (HOT) interfaces from the scenarios. The HOT interfaces serve as an initial screening to determine how much and where additional high-capacity transmission may be needed between the subregional pairs given the full set of sensitivity cases considered here.

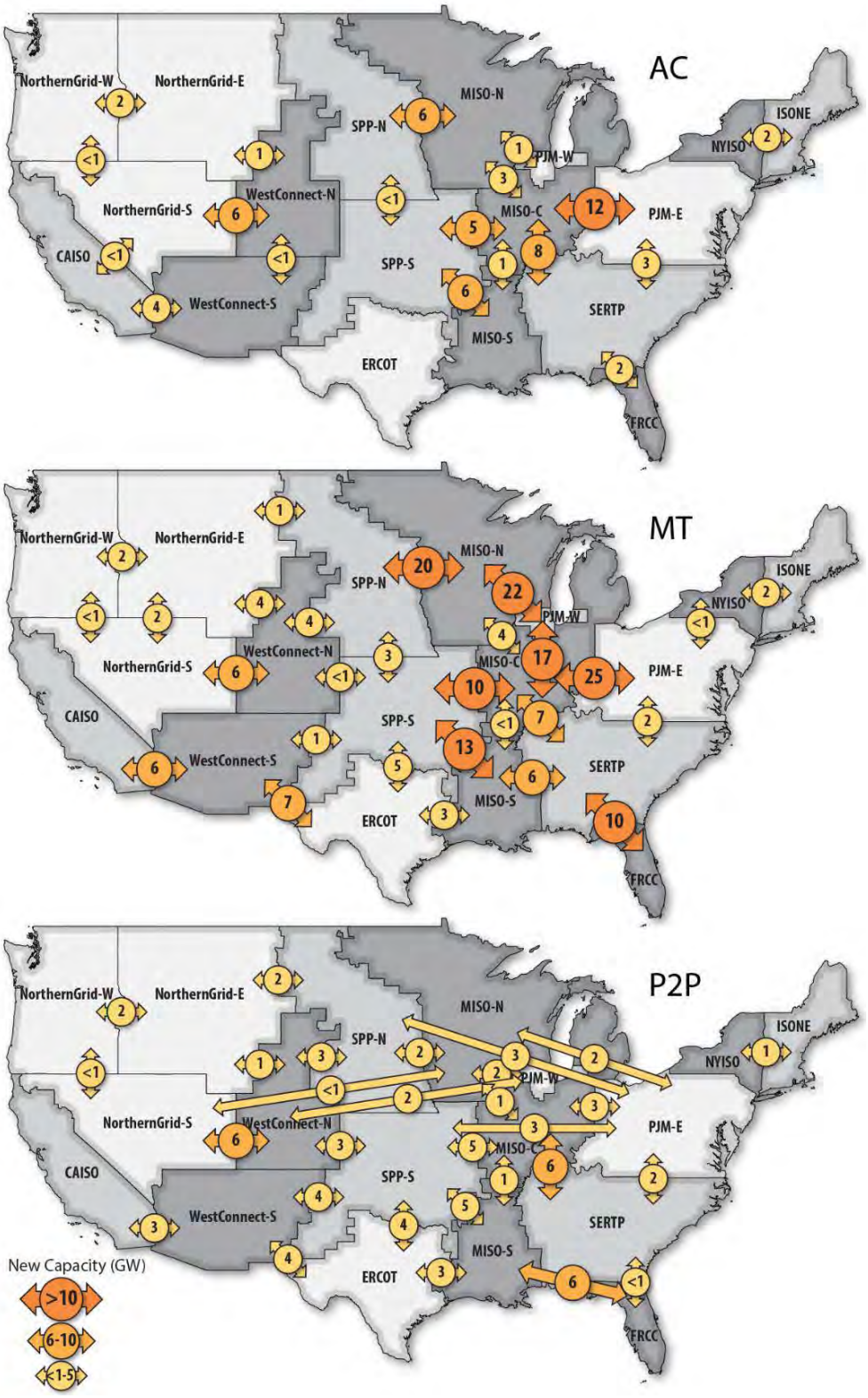
High Opportunity Transmission

An objective of the NTP Study is to identify potential transmission solutions that will provide broad-scale benefits to electricity customers under a wide range of potential futures. To support this objective, this text box presents a screening analysis to identify High Opportunity Transmission (HOT) interfaces between planning subregions developed using the scenarios presented in this chapter.

Subregional HOT interfaces are specified by the amount of transfer capacity expanded between a pair of planning subregions (Figure 1b) from 2020 to 2035. These interfaces are found by systematically evaluating this transfer capacity increase from the 16 scenarios (one core scenario plus 15 sensitivity cases) under the central demand/emissions assumptions (Mid-Demand, 90% by 2035) for each of the three accelerated transmission frameworks (AC, P2P, and MT). Specifically, a HOT interface capacity is defined as the expansion between subregions that occurs in 75% of the scenarios, i.e., the 25th percentile of transmission expansion. This 25th percentile is chosen to reflect robustness in development across a wide range of future conditions about technology costs and availability, renewable energy siting, and level of interregional coordination.

The following maps show HOT interfaces identified for the three accelerated transmission frameworks. In all frameworks, HOT interfaces are found for all regions although a concentration is found in MISO and neighboring regions. The HVDC frameworks (P2P and MT) generally have more HOT interfaces, and their capacities tend to be greater than those in the AC framework. The P2P framework includes long-distance connections, including between nonadjacent planning regions. The MT framework has the highest-capacity HOT interfaces with several having an increased transfer capacity of 10–25 GW. Although some HOT interfaces have very high capacities, a significant fraction of the benefits of interregional transmission can be realized with a smaller amount of expansion as revealed from a side analysis that tests the same scenarios with maximum limits on transmission development across major subregions.

Appendix F provides additional information for the HOT interfaces for each planning region. It also includes the 50th and 75th percentile results to inform more ambitious transmission development opportunities. The HOT interfaces are found by systematically examining the capacity expansion scenarios but are limited by the number and type of sensitivity cases modeled. Additional sensitivity cases would increase the robustness of the interfaces identified, and further assessments are required to determine the viability of any individual project that may align with the HOT interfaces shown. Nonetheless, these subregional HOT interfaces provide a general scale of how much new interregional transmission capacity is needed over the next decade to realize many of the decarbonization scenarios envisioned.



High Opportunity Transmission interfaces with Mid-Demand 90% by 2035 assumptions under the (top) AC, (middle) MT, and (bottom) P2P transmission frameworks

3.3.5 Zero-carbon power systems dominated by variable renewable energy can meet resource adequacy targets

The NTP Study uses a coupled ReEDS-PRAS modeling approach, described above, which results in power system reliability levels (for systems with net zero carbon emissions and generation mixes dominated by VRE) that fall comfortably within the range of resource adequacy targets used in industry (Figure 33). The median NEUE for the Mid-Demand 90% by 2035 scenarios across all model years, transmission frameworks, and sensitivity cases (384 total observations) is 0.9 ppm, well below the industry target range of 10–30 ppm (Alberta Electricity system Operator 2017; Electric Power Research Institute 2024; NERC 2024). In 2045 and 2050—the years in which these scenarios are constrained to net zero electricity system emissions—the median NEUE stays similarly low.

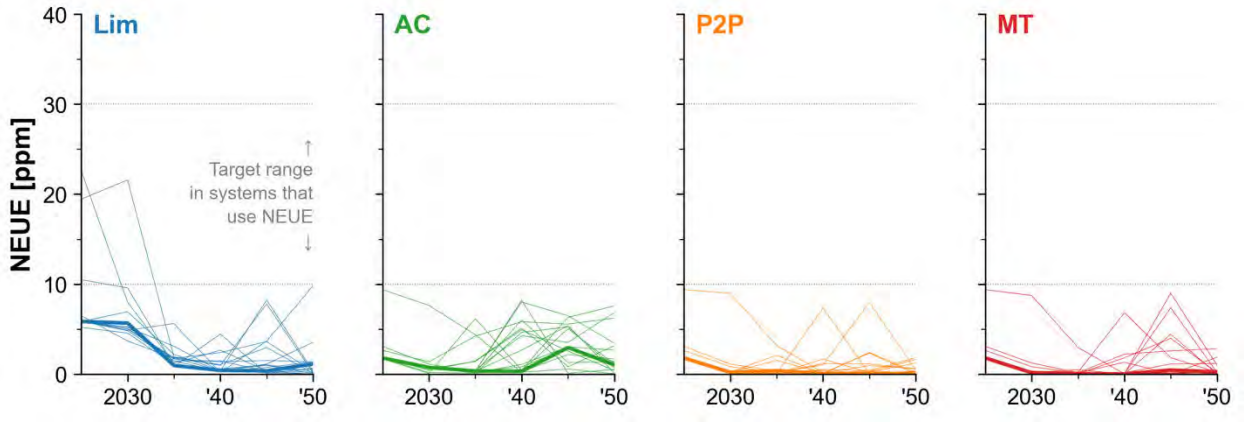


Figure 33. Normalized expected unserved energy (NEUE) in each transmission framework and sensitivity case with Mid-Demand 90% by 2035 assumptions.

Results for the core scenarios are indicated by thick lines; results for sensitivity cases are indicated by thin lines.

Because systems are planned to ensure a minimum RA target is met, there is no trend in RA outcomes between transmission frameworks. Instead, the value of transmission for RA is realized as the change in cost of meeting RA needs, discussed in Section 3.3.1.

A variety of technologies supports resource adequacy

As discussed in Section 2.1 and Appendix B, the coupled ReEDS-PRAS model addresses RA requirements by identifying “stress periods” with a high risk of unserved energy and including them in the co-optimization of generation, storage, and transmission capacity/operation in ReEDS. Though the nameplate capacity and average generation mix of the decarbonized systems explored here are dominated by wind and solar (Figure 23), wind and solar make up a smaller share of the generation mix during stress periods than during representative periods[37] (Figure 34). Hydropower and thermal technologies, conversely, make up a larger share of the generation mix

[37] Low availability of wind and/or solar on a given day can be the reason that day qualifies as a stress period.

during stress periods than during representative periods. These results show that all technologies—including wind and solar—contribute to the energy and RA needs although the relative contributions between technologies can vary significantly.

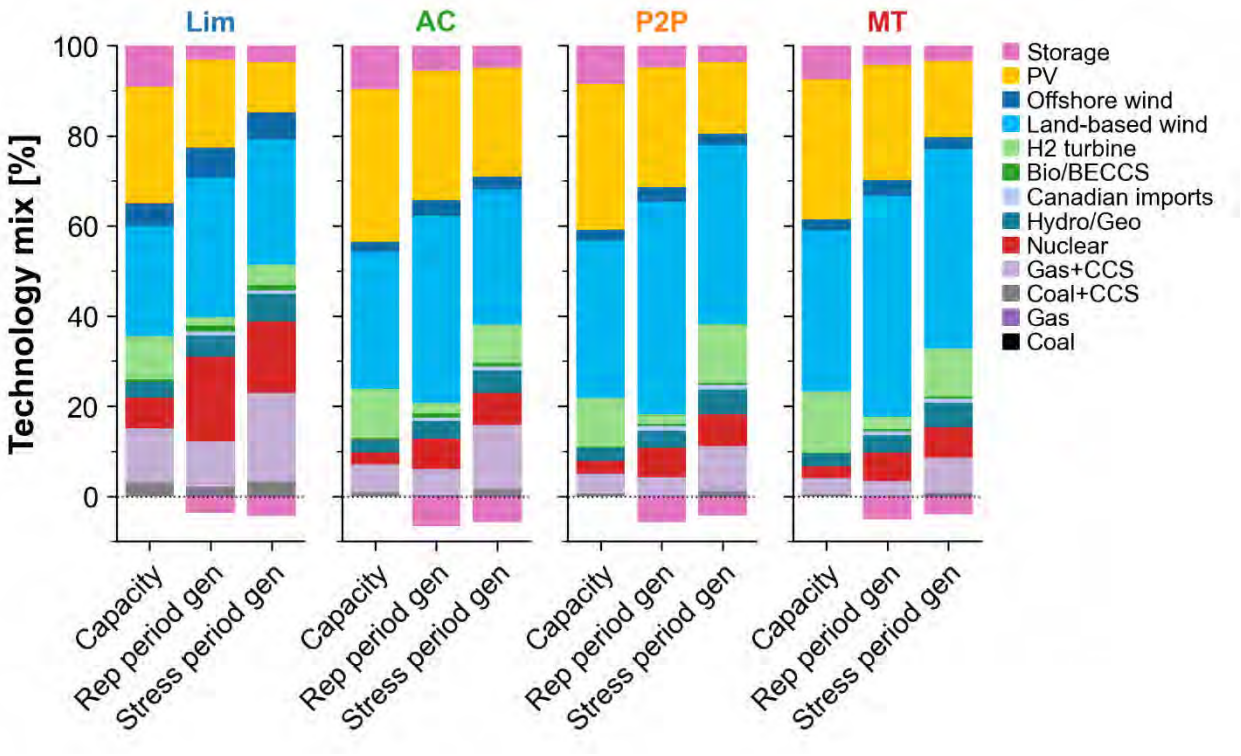


Figure 34. Nameplate capacity mix, representative period generation mix, and stress period generation mix for the core transmission frameworks in 2050 under Mid-Demand 90% by 2035 assumptions.

Stress periods in this study are modeled as coincident 24-hour days over the contiguous United States.

Though wind and solar contribute more to the bulk energy mix (the “Rep period gen” bars in Figure 34) than to the stress period resource mix, accelerating transmission deployment increases the contribution of wind and solar to the resource mix during stress periods. In the Mid-Demand 90% by 2035 scenario in 2050, wind and solar constitute 44% of the stress-period generation mix in the Limited transmission framework and 57%–64% in the accelerated transmission frameworks. The generation fractions provided here are for all hours of the modeled stress periods and for the contiguous United States as a whole; in particular hours and regions, the contribution of wind and solar can be much smaller (e.g., during low-wind or nighttime hours), and hydro/thermal technologies make up a larger share (Figure 35).

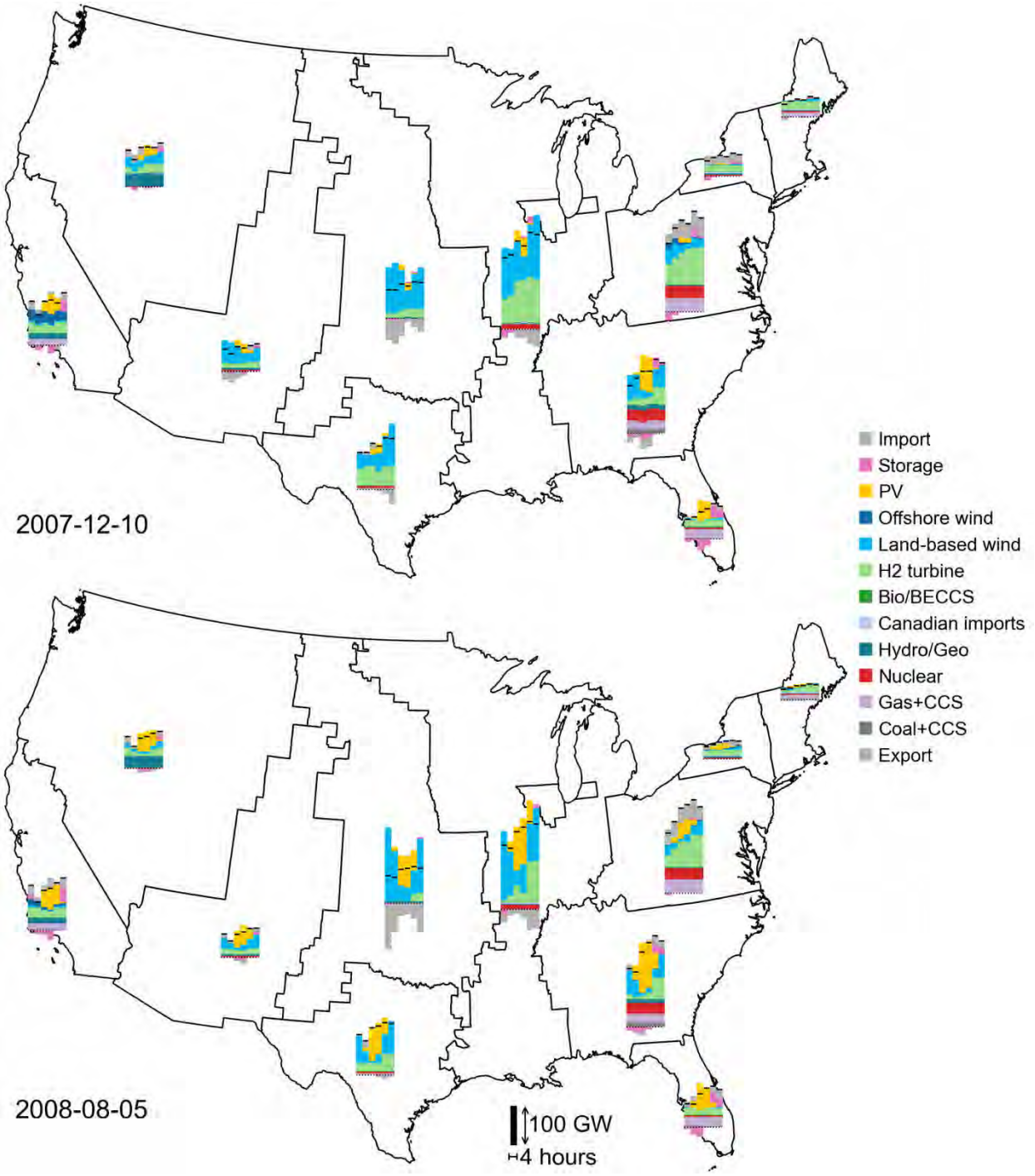


Figure 35. Regional dispatch in the MT framework under Mid-Demand 90% by 2035 assumptions in 2050 modeled in ReEDS during two example stress periods

Dates in this figure are given as year-month-day. The dates shown here refer to weather days from the 2007–2013 weather sample; the capacity and demand mix are for the 2050 model year. 2007-12-10 is the stress period with least VRE generation; 2011-08-05 is the stress period with peak load. Regional load is indicated by thin black lines. Storage charging and exports to other regions are shown as negative values. Daily profiles are at the 4-hour resolution used within the ReEDS model for this study.

Interregional transmission—over spatial scales larger than weather systems—enables the sharing of variable renewables during days with limited local resource availability

Figure 34 shows wind and solar make up a larger share of the stress period generation mix in the accelerated transmission frameworks than in the Limited framework. Though improved access to high-quality resource regions with uniformly higher capacity factors explains part of this trend, interregional transmission also smooths out the geographic variability of these weather-dependent resources, particularly for wind (Kempton et al. 2010; Grams et al. 2017; Goggin 2021).

On the least-windy day in the weather dataset for a given planning region, neighboring regions are often significantly windier (Figure 36). For example, on ERCOT's least-windy day (2012-09-15), when the daily average capacity factor of ERCOT wind is only 6%, the wind capacity factor is 31% in neighboring SPP and 34% in MISO (a ~5 times difference). For CAISO, where daily wind capacity factor drops to 2% on 2013-11-17, the capacity factor in neighboring WestConnect and NorthernGrid is 40%–45%, ~20 times higher. These opportunities are sometimes bidirectional: On WestConnect's least-windy day (7% on 2010-12-05), neighboring CAISO has a wind capacity factor of 42%, ~6 times higher.[38]

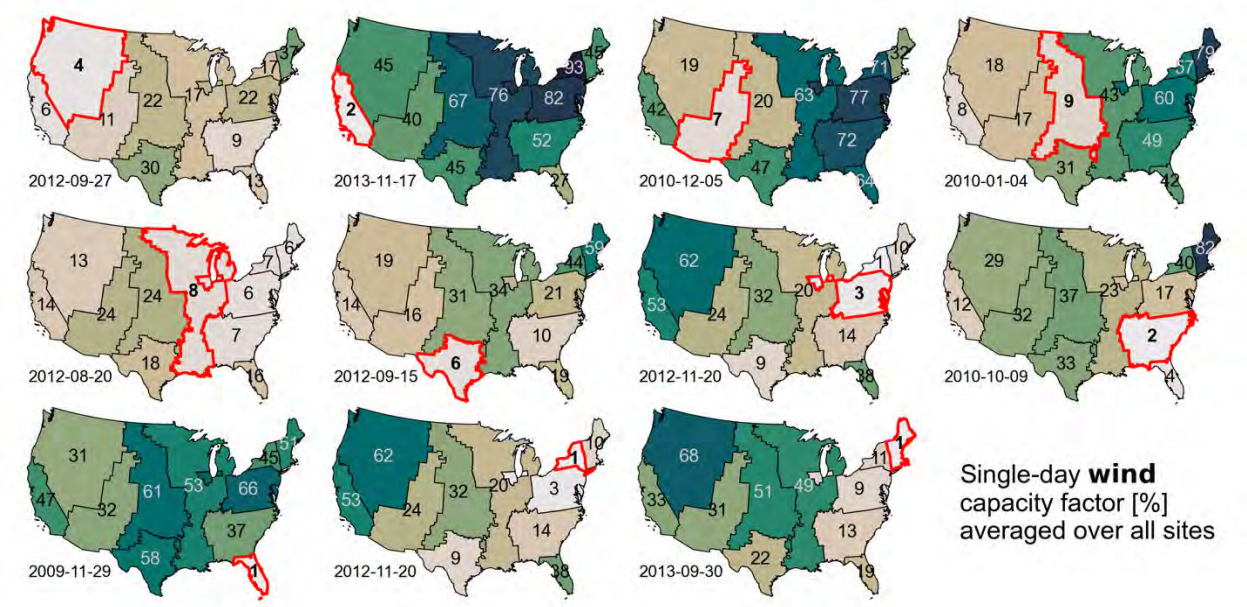


Figure 36. Single-day wind capacity factor on the least-windy day from 2007 to 2013 weather years in each planning region

For each map, the focused planning region is outlined in red, the date of the least-windy day in that region is given in the lower left, and the values and colors in each region represent the daily wind capacity factor on that date. Planning region values are taken as the available-capacity-weighted average modeled capacity factor over all resource sites in the planning region. Capacity factors are modeled using the reV model as discussed in Appendix A.2. Most of these sites are never developed; if only developed or higher-quality resource sites in each planning region were included, the capacity factors would be higher than shown here.

[38] Complementarity between different resource types—illustrated in Figure D-14—provides further flexibility: On 2012-08-20, MISO and all its eastern neighbors aside from FRCC have wind capacity factors ≤8%, but solar capacity factor in these regions is above average on this summer day.

Similar examples can be observed for solar (Figure 37), though to a smaller degree than for wind given the uniformly greater seasonal variability of solar (all of the lowest-regional-capacity-factor days for solar occur during winter, with fewer hours of sunlight available regardless of weather). Though there are some strong resource-sharing opportunities—on MISO's least-sunny day (1% on 2009-12-24), the capacity factor in neighboring PJM is ~10 times higher—there are also days when large fractions of the country have uniformly low resource: On 2007-12-28, no planning region east of SPP has higher than a 6% capacity factor. On ISONE's least-sunny day (1% on 2012-12-10), resource sharing would have to extend to MISO or SERTP to reach ≥5% capacity factor.

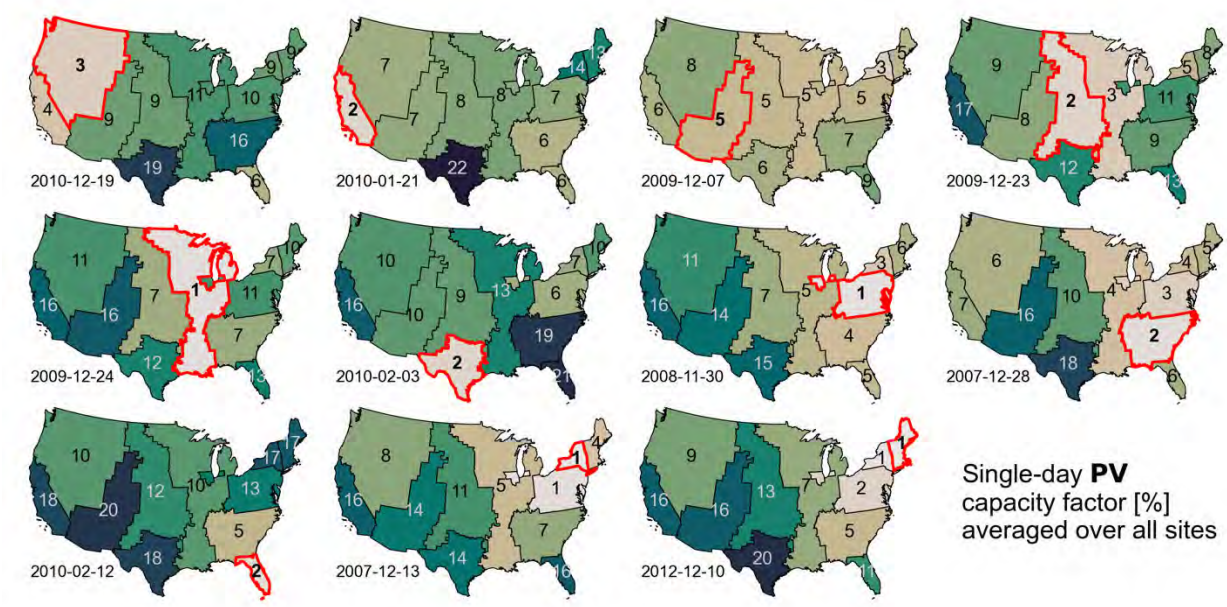


Figure 37. Single-day PV capacity factor on the least-sunny day from 2007 to 2013 weather years in each planning region

For each map, the focused planning region is outlined in red, the date of the least-sunny day in that region is given in the lower left, and the values and colors in each region represent the daily PV capacity factor on that date. Planning region values are taken as the available-capacity-weighted average modeled capacity factor over all resource sites in the planning region. Capacity factors are modeled using the reV model as discussed in Appendix A.2. Most of these sites are never developed; if only developed or higher-quality resource sites in each planning region were included, the capacity factors would be higher than shown here.

Electricity demand also demonstrates interregional variability, which can be smoothed by interregional transmission (Figure 38) although the opportunities are less pronounced than for wind and solar. Here, if adjacent planning regions reach peak demand on different days, they could have spare capacity to assist neighboring regions in meeting their peaks. The greatest opportunity observed in the Mid-Demand scenario for 2050 is on MISO's peak day of 2009-01-15, when demand in neighboring ERCOT reaches only 69% of its peak. For most regions on their peak-containing day, demand in neighboring regions is ~85%–90% of its regional peak.

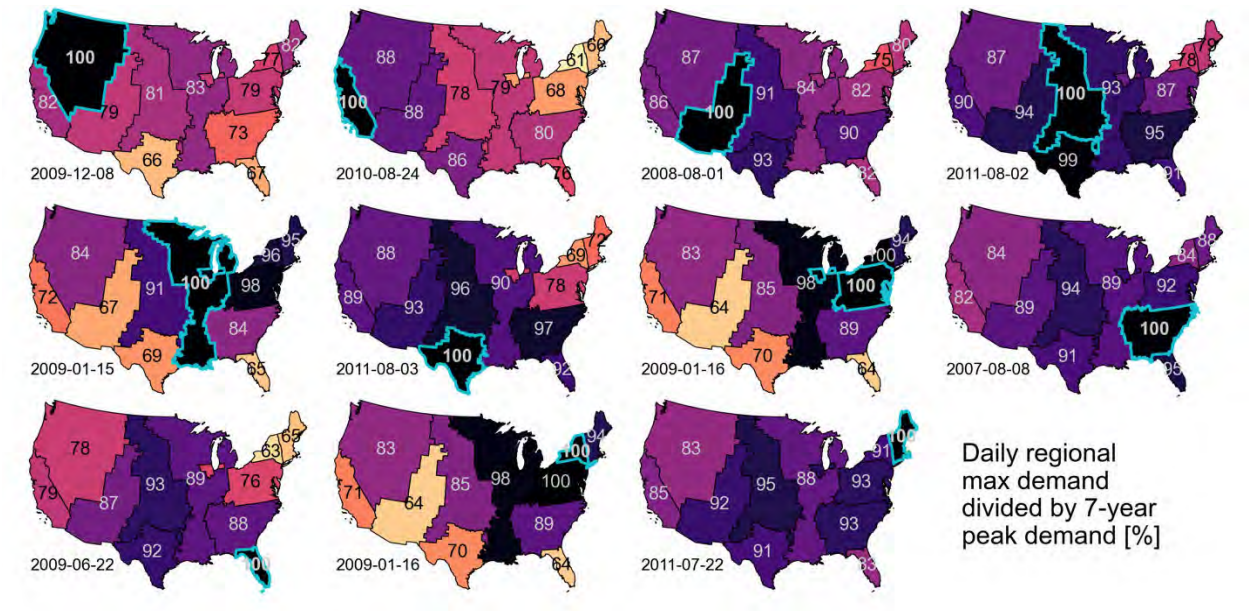


Figure 38. Daily regional maximum demand divided by 7-year peak demand for that region, shown for the regional peak demand day from 2007 to 2013 weather years for each planning region

For each map, the focused planning region is outlined in blue, the date of the peak demand day in that region is given in the lower left, and the values and colors in each region represent the relative regional peak demand (normalized to the total regional peak demand across all 7 weather years) on that date. For example, 2009-12-08 is the peak demand day for NorthernGrid over 2007–2013; on that day, CAISO demand reaches 82% of peak CAISO demand over 2007–2013. Demand data are from the Mid-Demand assumption for 2050.

Bidirectional power flows between regions support resource adequacy

Within the PRAS model, transmission is used only to avoid dropping load; PRAS does not consider variations in marginal cost between generation technologies. Transmission flows in PRAS thus illuminate the use of transmission specifically related to grid reliability when local generation alone does not meet RA needs.

A diversity of usage patterns is observed in the PRAS model results for interregional transmission in the accelerated transmission frameworks (Figure 39). Hourly flow patterns are presented in Appendix D.3. Some interfaces in the P2P framework are used almost entirely unidirectionally: for the SPP→SERTP, MISO→FRCC, and MISO→PJM interfaces, 99.9+% of RA flows are in the indicated direction on a megawatt-hour (MWh) basis. Others are bidirectional: For the MISO→ERCOT, NYISO→ISONE, ERCOT→WestConnect, MISO→SPP, and CAISO→NorthernGrid interfaces, the distribution of RA flows between the two directions is between 50/50 and 60/40, with the arrow denoting the predominate flow direction. For the SPP→PJM interface, the large majority (98%) of RA flows are from wind-rich SPP to demand centers in PJM, but ~900 hours in the 7-year weather sample have energy flows from PJM to SPP to help SPP meet its RA needs. This observation mirrors the examples shown in Figure 35 and Figure 36, where high-renewable-resource regions can still be aided by neighbors on locally poor resource days.

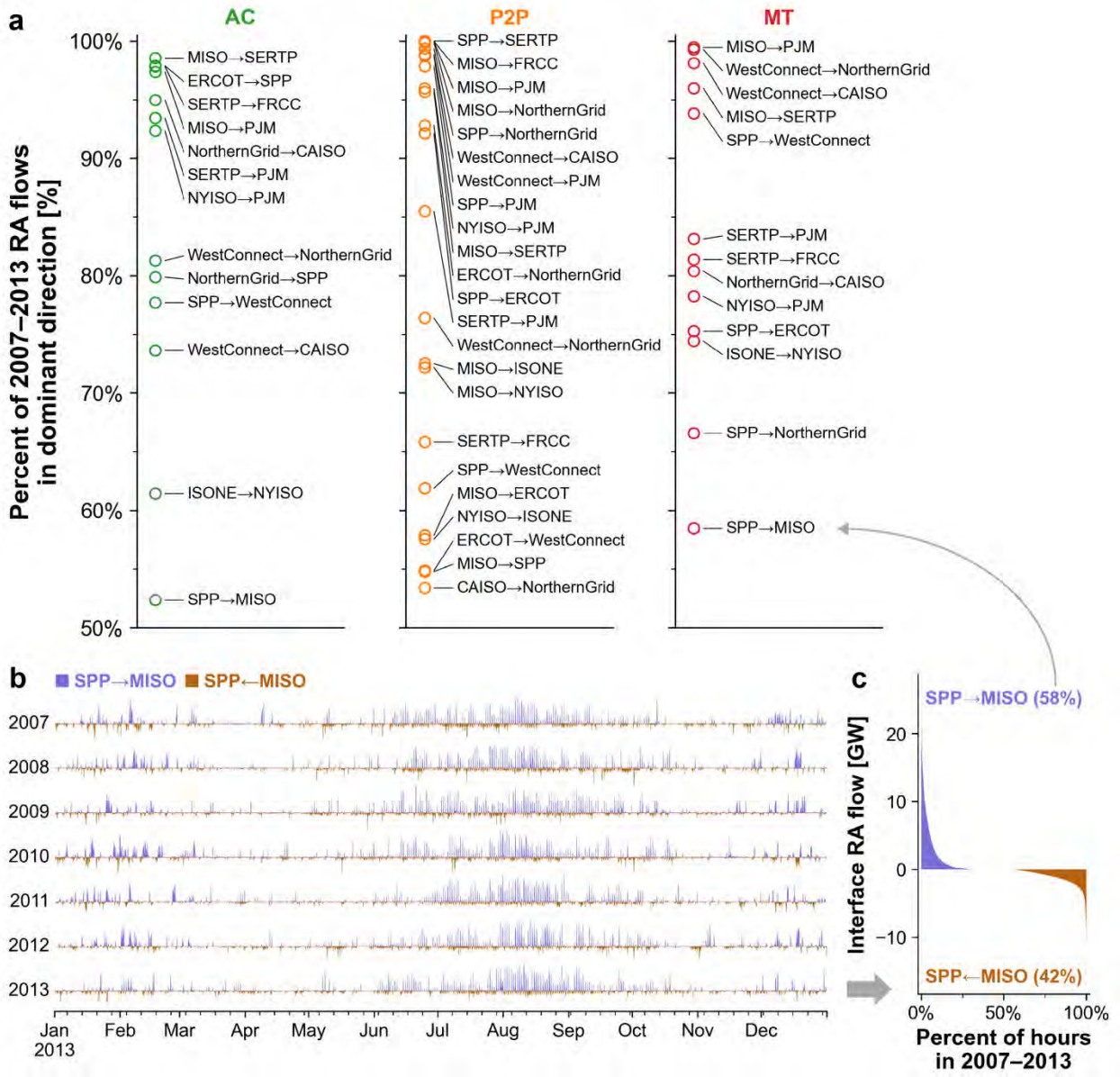


Figure 39. Bidirectional transmission flows between regions for resource adequacy in 2050 under Mid-Demand 90% by 2035 conditions as modeled by PRAS

For each interface between planning regions (Figure 1c), the dominant direction is determined by the fraction of total hourly flow modeled in PRAS on a MWh basis over the 7 weather years spanning 2007–2013, and the percent of total flow in the dominant direction for each interface is shown in panel (a). Illustrative hourly flows and the sorted distribution of flows for the SPP→MISO interface in the MT framework are shown in (b) and (c), respectively.

Interregional resource adequacy coordination reduces the cost of meeting resource adequacy requirements

Because ReEDS co-optimizes the deployment and operation of generation and transmission to meet demand in both representative and outlying periods at least cost, it is difficult to disentangle the “energy value” and “RA value” (or “capacity value”) of interzonal transmission investments within a single ReEDS scenario.

To isolate the effects of interregional coordination of RA planning (or "RA sharing") on system cost and transmission deployment, two scenarios are compared: the "core" scenario using default assumptions and the "No RA sharing" sensitivity case where transmission flows are not allowed between planning subregions (Figure 1b) to meet RA needs. In effect, this sensitivity case requires each planning subregion to meet its RA needs solely from resources within its own borders rather than rely on interregional transmission and excess resource availability from neighbors.

Total costs through 2050 are notably higher in the "No RA sharing" case than in the "core" scenario that allows regions to coordinate to meet RA needs—roughly $200 billion higher in the Limited, AC, and P2P transmission frameworks and ~$380 billion higher in the MT framework (Figure 40a). Substantial savings could accrue from using existing interregional transmission for RA sharing, as evidenced by the large savings in the Limited transmission framework where new interregional transmission additions are not allowed.

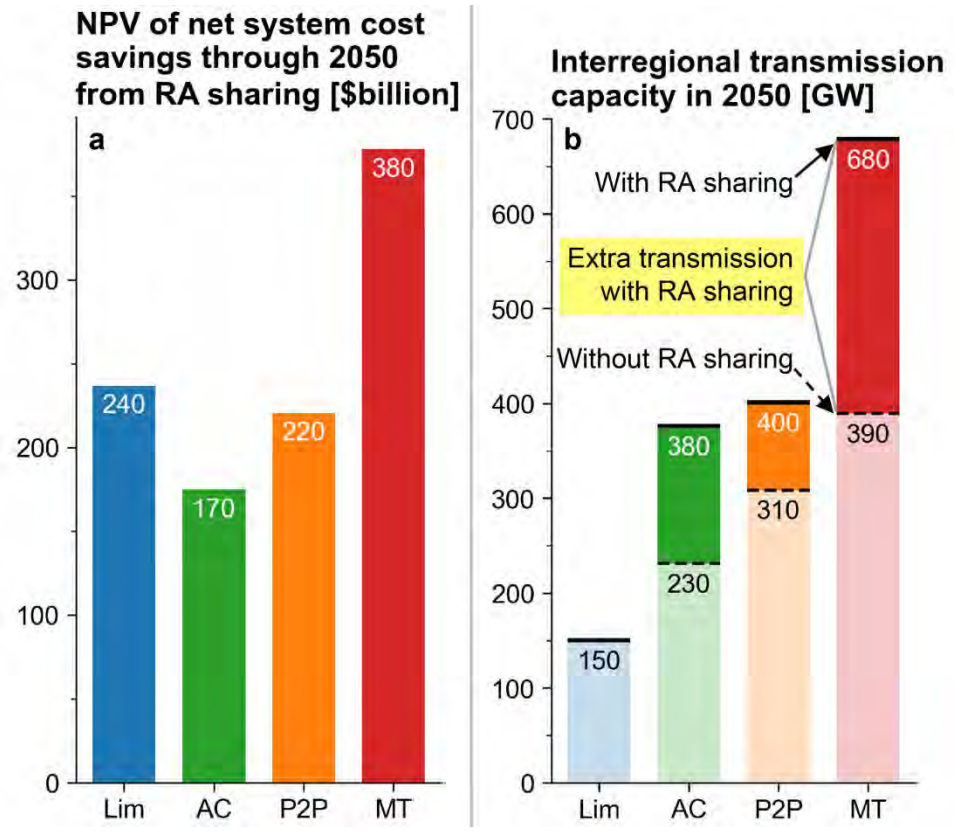


Figure 40. Impact of the allowance of interregional RA sharing on system cost (a) and optimized interregional transmission capacity (b)

System cost savings (as shown in panel (a)) for each of the demand and emissions assumptions shown in Figure 3 are provided in Figure D-17.

Significant amounts of interregional transmission are built primarily to serve resource adequacy needs

The ability to use interregional transmission to meet RA needs also leads to substantial additions of new interregional transmission in scenarios that allow it (Figure 40b and Figure 41). Cost-minimizing interregional transmission capacity additions drop by ~40%–60% across the three accelerated transmission frameworks if RA sharing is not allowed, contributing to the ~$200–350 billion higher system cost compared to when RA sharing is allowed. Large interregional transmission additions in the upper Midwest drop out of the optimal solution if RA sharing is not allowed, highlighting the significant value of transmission during scarce but high-consequence periods of system stress and aligning with recent studies exploring the contribution of short-duration electricity price spikes to long-distance transmission value (Millstein et al. 2022).

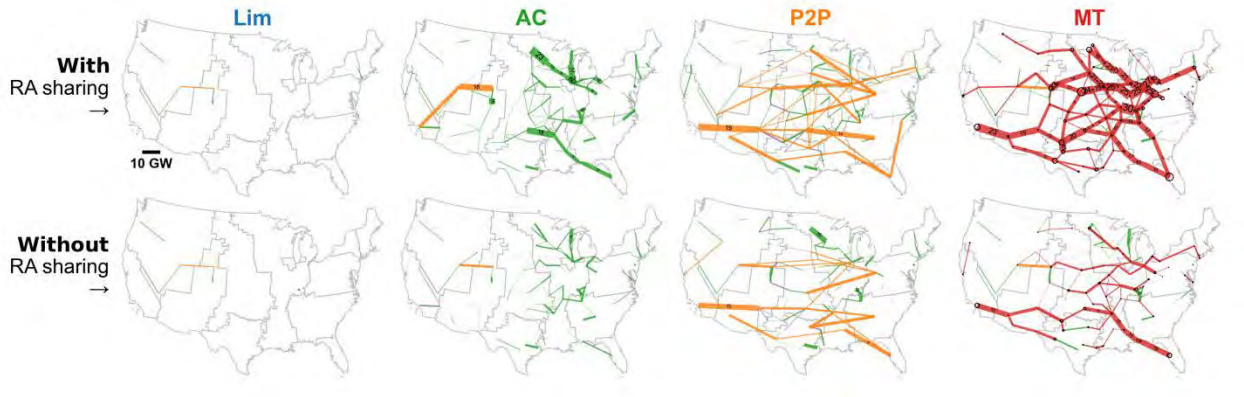


Figure 41. New transmission through 2050 with Mid-Demand 90% by 2035 assumptions for the four transmission frameworks with (top) and without (bottom) RA sharing between planning subregions.

Conclusions

This chapter documents the methods, assumptions, scenario design, and results from the zonal capacity expansion, resource adequacy, and transmission value analyses of the NTP Study. The analysis is designed to assess the role of transmission in the future U.S. electricity system. It compares how different transmission frameworks—ranging from those where transmission expansion is limited to futures with highly coordinated transmission planning and development with advanced technologies—might impact this role. The analysis includes 96 scenarios that capture a broad range of possible market, policy, and technology uncertainties.

Overall, the analysis finds that accelerating transmission expansion enables decarbonization of the U.S. power system at lowest cost by enabling the interconnection and delivery of large amounts of inexpensive wind and solar energy—and other low-emissions resources—to all electricity consumers and to support resource adequacy.

Under Current Policies scenarios—which do not apply a limit on national emissions—accelerating transmission expansion can lead to cumulative CO_2 emissions reductions of 10.2–11.2 billion metric tons (43%–48%). With a limit on national CO_2 emissions, the benefits of transmission expansion are expressed through lower total system costs. These benefits increase with more rapid grid decarbonization and greater electrification. With the core central decarbonization assumptions, which include 90% emissions reductions by 2035 and Mid-Demand growth (2.0%/year), accelerated transmission expansion saves $270–490 billion in electricity system expenditures through 2050. The system cost savings outweigh expenditures for transmission, resulting in high transmission benefit-cost ratios (above 1.5) for all scenarios and sensitivity cases.

Significant amounts of transmission are added in the decarbonized systems modeled. In the central decarbonization scenarios, total U.S. transmission grows to 2.4–3.5 times the size of the 2020 grid by 2050 across the accelerated transmission frameworks; the amount of growth scales with decarbonization rate and demand growth. Transmission expansion occurs at all scales, including local interconnections for new wind and solar, longer-distance interregional transmission, and, when allowed, seam-crossing transmission that increases the transfer capacities between the Western, Eastern, and Texas interconnections. Scenarios that consider HVDC additions result in greater total regional and interregional transmission expansions and yield the largest economic benefits.

Transmission is added in all regions of the country, but the highest concentration is developed in the central wind belt. This geographic distribution of transmission development is robust across the sensitivity cases modeled. The amount and location of interregional transmission expansion between subregional pairs by 2035 is identified based on the full suite of sensitivity cases and referred to as High Opportunity Transmission (HOT) interfaces. Further study is needed to identify potential transmission projects that align with the subregional HOT interfaces.

Resource adequacy is considered in the development of all the scenarios modeled to ensure RA needs are met in decarbonized systems, including those with significant transmission expansion and much greater reliance on remote and variable resources. A variety of technologies contributes to meeting adequacy needs. Transmission can support RA by enabling the sharing of resources and increasing geospatial diversity of load and VRE, especially with interregional transmission over spatial scales larger than weather systems. Without interregional RA coordination to take advantage of transmission's capabilities to support RA, total system costs to decarbonize are estimated to increase significantly and less transmission development occurs. In other words, RA is an important source of value for transmission in the future.

These findings demonstrate how accelerating transmission expansion can support a lower-cost transition toward energy system decarbonization while maintaining reliability. However, the complexities of transmission planning require higher-fidelity analysis to increase confidence in these results. For example, this chapter examines resource adequacy for the scenarios, but operational reliability and resiliency are not analyzed. The scenario analysis presented in this chapter provides the starting point for further study. Subsequent chapters present the production cost, power flow, and other detailed analysis for a subset of—and variations to—the scenarios described in this chapter.

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Appendix A. Regional Energy Deployment System (ReEDS) Model

The National Renewable Energy Laboratory (NREL) ReEDS model is a capacity expansion model for the contiguous United States electricity system. ReEDS co-optimizes generation, storage, and transmission to find the systemwide least-cost portfolio that meets demand, grid reliability, and policy requirements. For this study, ReEDS starts in 2020 and optimizes each 5-year solve period sequentially through 2050. The ReEDS documentation (Ho et al. forthcoming) and latest NREL Standard Scenarios report (Gagnon et al. 2024) provide further details about the model. The model is open source and can be accessed at https://www.nrel.gov/analysis/reeds/. Earlier versions of ReEDS have been used in several transmission, grid integration, and policy and scenario studies, such as the North American Renewable Integration Study (Brinkman et al. 2021), Denholm et al. (2022), and the Electrification Futures Study (C. Murphy et al. 2021).

This appendix highlights newer capabilities in ReEDS that are relevant to the NTP Study.

A.1 Transmission Modeling

This section describes multiple aspects of transmission modeling in ReEDS: 1) existing interface transfer limits for the zonal structure of the model, 2) prescribed transmission projects in the scenarios, 3) transmission cost assumptions, 4) high-voltage direct current (HVDC) specific assumptions and modeling, and 5) assumptions for the annual build limits applied in the Limited framework.

For generation and storage, the model is initialized using unit-level data from the EIA Annual Energy Outlook. The capacity for each of these units is associated with a generator or storage type and one of the 134 model zones.[39] Retirements and new capacity builds are primarily endogenously determined as part of the model's decision-making process.[40]

Initializing the current transmission capacity for the zonal model is more challenging because of the alternating current (AC) nature of power flow dictated by Kirchhoff's laws. In particular, the aggregate interface transfer limit between two zones cannot be simply approximated by the sum of thermal capacities of the lines crossing the zonal boundary. A better approximation for the interface limits uses a method documented in Brown et al. (2023), which applies a DC power flow approximation approach. The approach starts with a nodal transmission dataset and results in estimates for the maximum transfer capacities across all interfaces for the 134 model zones.

[39] Multiple vintages are also tracked particularly to reflect the range of heat rates for thermal generators.
[40] Recently installed (2021–2023) capacity and projects that are under final stages of deployment, as identified by EIA, are also prescribed for development in the model across all scenarios. Similarly, announced plant retirements from EIA are also modeled.

For most interfaces, the method assumes all lines are available when estimating the interface transfer limits. However, for interregional interfaces—interfaces between zones in different transmission planning subregions, e.g., between SPP-North and MISO-North—a more conservative approach where the single largest line crossing the interface is assumed to be unavailable, reducing the maximum transfer limits between such zones, is applied. This approach serves as a proxy for the transfer capacity between planning subregions accounting for N-1 contingencies. One MW of new transmission between two zones adds one MW of transfer capability between the zones (no derate), but the sum of new transmission crossing between transmission planning subregions is derated by 15% for the determination of maximum interregional flows (so if 100 MW of new transmission capacity is added across interfaces between SPP-North and MISO-North, the transfer capability between SPP-North and MISO-North is increased by 85 MW) as a linear approximation of security constraints.

The ~65,000-bus North American Renewable Integration Study (NARIS) database (Brinkman et al. 2021) represents expected transmission capacity for 2024 and is used to estimate currently installed transmission in ReEDS. ReEDS begins installing new, currently unplanned transmission in the 2030 solve year to minimize total system cost. Select transmission projects that are under construction but not yet completed are prescribed to be built in the model during the 2030 solve period.[41]

In addition to the existing transfer capacity and prescribed transmission projects, ReEDS can decide to build new transmission capacity as part of its co-optimization framework. The cost for new transmission is based on cost estimates from Western Electricity Coordinating Council (WECC) (Western Electricity Coordinating Council 2019), MISO (MISO 2021), Southern California Edison (Southern California Edison 2021), and a representative southeast utility. Transmission cost estimates also account for terrain, land type, and other siting factors included in the Renewable Energy Potential (reV) model (Lopez et al. 2024).[42] For interzonal transmission, distances between model zones are estimated based on a least-cost path method between the largest load centers in the zones. These distances are longer than the straight-line paths between the load centers. For interzonal AC transmission, assumed costs are based on new greenfield 500-kilovolt (kV) (1500-MW) single-circuit lines (Western Electricity Coordinating Council 2019). Figure A-1 shows the resulting interzonal AC transmission capital costs that result from this process. Annual transmission fixed O&M costs are assumed to be 1.5% of the upfront capital costs per year (European Commission. Joint Research Centre. Institute for Energy and Transport. and SERTIS. 2014).

[41] Prescribed transmission projects in the scenarios include Colorado Power Pathway (3,274 MW), TransWest Express (3,000 MW), Greenlink Nevada (2,000 MW), and Boardman to Hemingway (1,732 MW). Several other transmission projects, some announced after the analysis was completed, are at various stages of development. Their exclusion does not imply any judgment about their viability.
[42] https://github.com/NREL/reV

The same approach for estimating transmission costs is used to estimate interconnection costs for new wind and solar capacity (see Section A.2) but with lower voltages and associated higher costs on a per MW-mile basis.

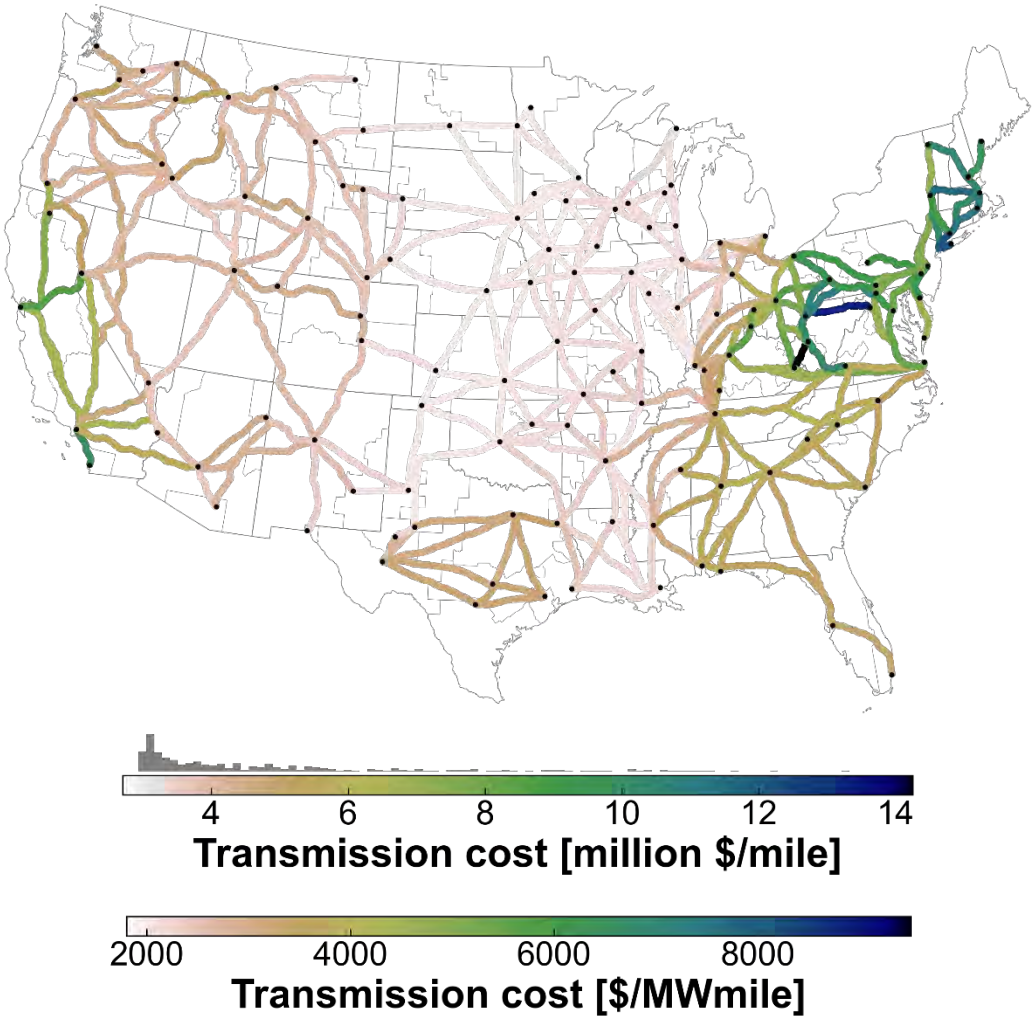


Figure A-1. Interzonal AC transmission cost assumptions

Direct current (DC) transmission line costs are assumed to be approximately 60% less than the $/MW-mile costs shown in Figure A-1 for AC transmission based on the MISO cost estimation guide (MISO 2021). However, DC transmission has the added cost of the converter stations. These are assumed to be $140/kW for line-commutated converters (LCCs) and back-to-back (B2B) interties and $180/kW for voltage source converters (VSC), also based on MISO (MISO 2021).

For the multiterminal (MT) framework, HVDC connection options are the same as those shown in Figure A-1 for AC transmission. For point-to-point (P2P), a new set of long-distance 195 candidate connections is included (Figure 2c). These are identified based on the highest wind resource and load centers in each region. Distances between these points are also based on the least-cost path estimation method.

Transmission losses are approximated based on distances between the zone "centers" (taken as the largest urban center when available, or a large transmission substation for zones without urban areas). Line losses are assumed to be 1% per 100 miles for AC transmission and 0.5% per 100 miles for DC. Losses are also modeled for the AC to DC conversion with 0.7% losses assumed for LCC technologies (used in the P2P framework) and 1.0% for VSC (used in the MT framework) (Alassi et al. 2019).

As a linear model, ReEDS considers continuous amounts of transmission capacity—with transmission costs in units of dollars per MW-mile—rather than discrete transmission circuits or projects. This simplification can lead to unrealistically sized transmission lines, particularly for HVDC transmission under the P2P and MT frameworks. To partially mitigate this, the analysis applies an iterative approach with two model runs for each of the scenarios under the HVDC (P2P and MT) frameworks. The first run uses all possible candidates. During the second, HVDC connections for which ReEDS builds less than 1.5 GW of capacity by 2050 are excluded.[43] This approach does not preclude small capacities but greatly reduces their number. ReEDS does not comprehensively account for additional upgrades or reinforcements for expansion of high-voltage DC or AC lines—e.g., that may be necessary to address voltage or stability issues—but estimated network reinforcement costs are included for new wind and solar development (see next section).

Under the Limited framework, a constraint is applied to the annual rate of transmission deployment. This rate is based on the maximum amount of transmission build in the United States over the past 10 years (2014–2023). Data from Federal Energy Regulatory Commission (FERC) collected by Lawrence Berkeley National Laboratory (LBNL) (Wiser et al. 2023) are used to estimate this maximum. The historical transmission data are reported by voltage and miles. To use this in ReEDS requires converting the voltage into capacity, and the following simple conversion factors are assumed: 400 MW for ≤230 kV, 750 MW for 345 kV, and 1500 MW for 500 kV. This approach results in 1.83 TW-mile/year of maximum annual transmission builds.

A.2 Wind and Solar Supply Curves

Assumptions for wind and solar developable potential, resource quality, and transmission access used in ReEDS are developed from the reV model (Maclaurin et al. 2021). reV is a high-resolution geospatial tool that considers renewable resources, land availability, hourly generation profiles, and transmission interconnection costs for approximately 60,000 potential sites across the contiguous United States. The most recent results and assumptions of the reV analysis for land-based wind and utility-scale solar photovoltaics (PV)[44] are documented by Lopez et al. (2024) and summarized below.

The technical resource potential for wind and solar is affected by the available land that could be developed. Land availability is estimated by considering siting suitability and

[43] For the scenarios translated for nodal modeling (Chapter 3), this iteration is also applied in 2035 instead of 2050 because the nodal modeling is conducted for 2035 systems.
[44] reV is also used similarly for offshore wind and concentrating solar power.

spatial exclusions from other uses. These siting considerations include terrain (e.g., slope, elevation), airspace and defense (e.g., airports, radar), environmental factors (e.g., endangered species habitat, wetlands, national parks and conservation areas), and siting regulations (e.g., setbacks from existing structures, roads, railroads, transmission lines, and pipelines). Default exclusion assumptions used for nearly all scenarios are based on the "Reference Access" case (Lopez et al. 2024). Under these assumptions, the total developable areas for wind and PV across the contiguous United States are 1.9 million square kilometers (km^2) and 2.6 million km^2, respectively. These land areas correspond to a technical potential of 11 TW of capacity potential for wind and 112 TW for PV; the higher PV potential is because of the relatively lower total land use requirements.[45] The developable potential for these resources is not spatially uniform with generally lower resource potential in locations with higher populations and associated built environment. Figure A-2a,c shows maps of the assumed resource potential for wind and solar, respectively, under the default assumptions. This available potential represents *options* that ReEDS could choose to deploy based on its optimization framework, which is much larger than the resulting buildout in the scenarios. ReEDS aggregates these available sites into its 134-zone structure but includes additional resource classes and transmission cost bins (Ho et al. forthcoming).

To capture the uncertainty associated with renewable energy siting over the next 3 decades, a Siting Limited sensitivity (Section 2.3.5) is included. For the Siting Limited sensitivity, the "Limited Access" siting regimes from Lopez et al. (2024) replace the Reference Access assumptions. Limited Access has more stringent exclusions, such as greater environmental exclusions and much larger setbacks that represent social challenges with siting. In this case, the developable area (and capacity) for wind is reduced to 800,000 km^2 (5.9 TW) and to 1.4 million km^2 (58 TW) for PV. As shown by Figure A-2b,d, the available resources are even more concentrated in the central regions of the country with lower population densities.

[45] The disturbed land area for these technologies differs, with <5% of the area of wind plants from roads, pads, and other infrastructure whereas approximately 90% of the area is covered by solar panels and other infrastructure.

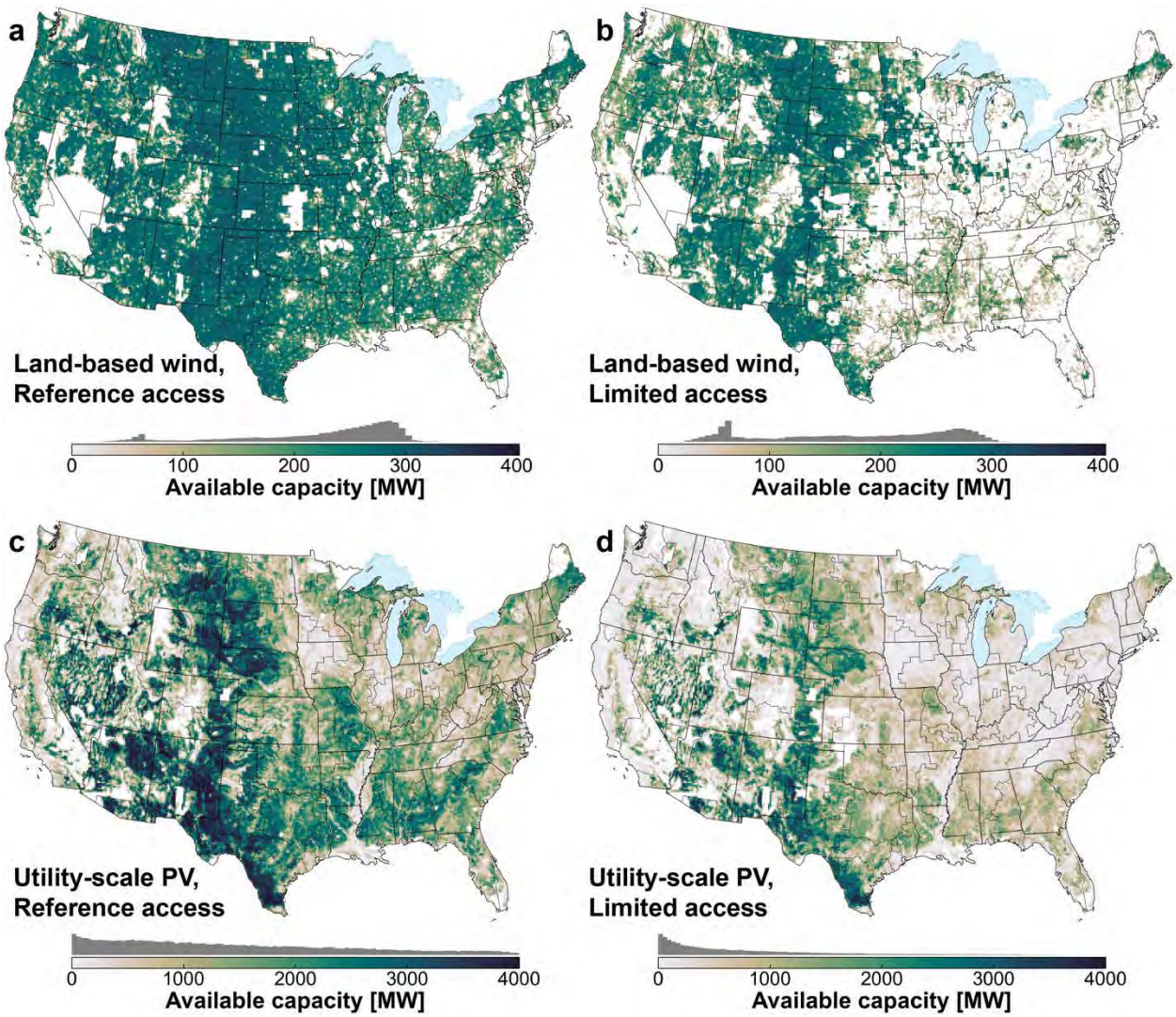


Figure A-2. Available land-based wind (a, b) and utility-scale PV (c, d) capacity under Reference Access (a, c) and Limited Access (b, d) assumptions

Histograms of available capacity by site are included above color bars. Note the difference in color scale limits between wind (a, b) and PV (c, d).

In addition to the developable potential, reV also estimates the performance (capacity factor) and generation profiles for each of the ~60,000 sites. Generation is modeled using the System Advisor Model[46] and based on meteorological data (e.g., wind speed, irradiance, temperature) from the 2-km resolution WIND Toolkit (Draxl et al. 2015) and 4-km resolution National Solar Radiation Database (Sengupta et al. 2018), including losses. Hourly generation is modeled for 7 weather years (2007–2013) for which coincident wind, solar, and demand data are available. The wind and solar technology assumptions are based on the Annual Technology Baseline (ATB) 2023 Moderate case for 2030.

[46] https://sam.nrel.gov/

Figure A-3 shows supply curves—the resource potential (in GW) ordered by lowest levelized cost of energy (LCOE)[47] in 2030—based on the land availability and performance assumptions from reV. The dashed lines show the supply curves without considering interconnection costs (Site LCOE). Interconnection costs as modeled in reV include spur lines to connect the renewable energy site to an existing substation that is the point of interconnection (POI), POI substation upgrade costs, and network reinforcements that represent other upgrades needed for the grid network. The underlying equipment costs and routing methods associated with these are based on the same sources used for interzonal transmission (Section A.1) but based on a wider range of voltages (Lopez et al. 2024). For network reinforcement costs, assumed per mile costs for upgrades are 50% of the cost of greenfield transmission and effective distance of upgrades based on the POI location and the largest load center in each of the 134 model zones (traced along the existing transmission system). This is a simplified approach to estimating interconnection costs but provides regionally varying costs that are approximately aligned with empirically observed costs (Seel et al. 2023). Figure A-3 shows how including interconnection costs (All-in LCOE, solid lines) is estimated to increase LCOEs by at least $5–$10/MWh for many locations. The modeling does not choose sites and technologies based on LCOE; LCOEs from Figure A-3 are shown to indicatively display the resource potential and quality assumed.

[47] ReEDS does not select resources based on LCOE. For example, options with higher LCOE can be chosen if their profiles are better aligned with system needs or the locations are preferred because of transmission congestion or for other reasons.

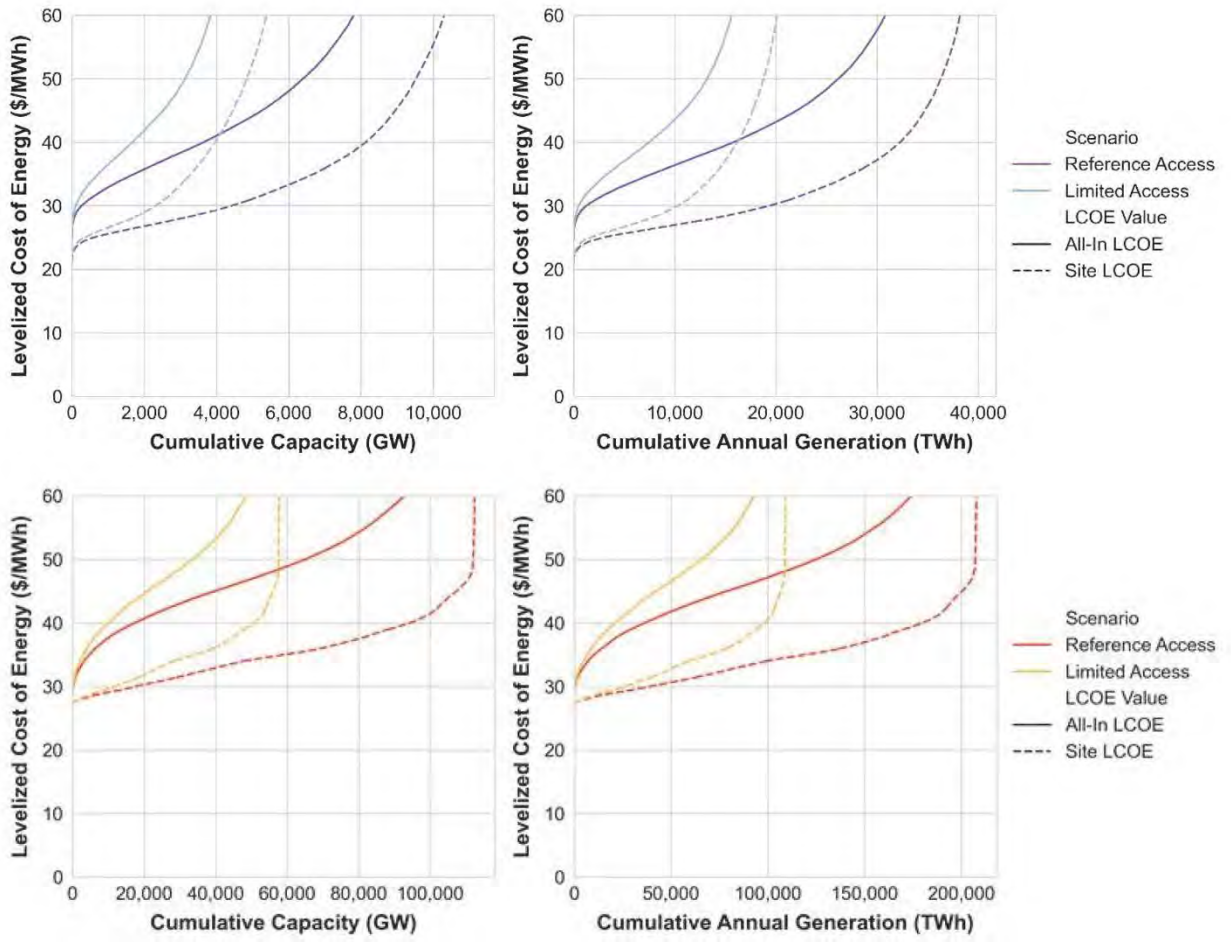


Figure A-3. LCOE supply curves for land-based wind (top) and solar PV (bottom)

Source: Adapted from Lopez et al. (2024). LCOEs are based on 2030 technology assumptions. Values above $60/MWh are not shown. "Site" LCOE excludes interconnection costs. "All-in" LCOE includes interconnection costs.

The interconnection costs modeled here are reflected in ReEDS, and these expenditures are tracked as local transmission investments. Local transmission distances and capacities—usually reported in MW-miles—also use the spur line distances and traced network upgrades.

A.3 Hydrogen Modeling

Hydrogen production and use for grid applications is endogenously modeled in ReEDS for the NTP Study. In other words, capacity for electrolyzers, hydrogen storage, and hydrogen-fueled generation are all decisions made by the model considering their assumed costs and constraints. For the NTP Study scenarios, hydrogen production is modeled via electrolysis only; steam methane reforming with or without carbon capture and storage (CCS) is not considered. In the default scenarios, electrolyzer costs are assumed to decline from $1,750/kW in 2022 to $550/kW in 2030 and remain constant after 2030 (DOE 2023b). In the Electrolyzer Low Cost sensitivity, electrolyzer costs decline to $157/kW by 2050 (DOE 2023b).

The model includes the electricity demand needed for electrolysis, which increases overall demand beyond the level shown in Figure 5 and Figure 6. Two forms of geological hydrogen storage—salt caverns and hard rock formations—are included as well as the ability to construct storage in underground pipe systems. Data on the availability of geological storage are taken from Lord et al. (2014) (Lord, Kobos, and Borns 2014). Costs for all three storage options are based on Papadias and Ahluwalia (2021) (Papadias and Ahluwalia 2021) and are approximately $40/kilogram of hydrogen (kg-H_2) for salt caverns, $65/kg-$H_2$ for hard rock, and $590/kg-$H_2$ for underground pipes. Electricity generation based on hydrogen is modeled to be from combustion turbines (CTs). These can be new greenfield H_2-CTs or can be retrofitted from existing natural gas (NG) power plants. The cost of greenfield H_2-CTs is assumed to be the same as that of new NG-CTs except with a 3% cost increase to account for adding a clutch to enable the CT to operate as a synchronous condenser (Denholm et al. 2022). Upgrades from NG-CT to H_2-CT are assumed to be 33% of the cost of a new plant, and upgrades from natural gas combined cycle (NG-CC) to H_2-CT are assumed to be 55% of the cost of a new plant because of the need to upgrade the steam turbine as well. Heat rates are assumed to be the same between H_2-CTs and NG-CTs.

Hydrogen storage levels are tracked chronologically over the modeled weather year at daily resolution within each model zone. In this way, the modeled hydrogen option is representative of seasonal storage and serves the primary purpose of supporting resource adequacy in the scenarios. Transport of hydrogen between zones is not allowed. Future work is needed to assess the relative trade-offs between hydrogen and electricity transmission. In addition, the scenarios do not include the use of hydrogen outside of the electricity sector, e.g., for use in industry and transportation. And, as noted in Section 2.3.2, hydrogen tax credits are not included in this study because the final policy was not released when the analysis was completed.

A.4 End-Use Emissions

The three electricity demand cases (Low, Mid, High) are based on different levels of electrification and associated reductions in end-use emissions as described in Section 2.3.3. Figure A-4 shows how direct emissions from the end-use sectors (e.g., vehicle tailpipe emissions for transportation, emissions from natural gas combustion in furnaces and water heaters in buildings, and emissions from heating and other processes in industry) vary across these cases. The power sector emissions results from ReEDS can be combined with these to estimate total energy emissions in the United States; however, care is needed to account for emissions from indirect electrification because consumption of hydrogen outside the power sector is not included.

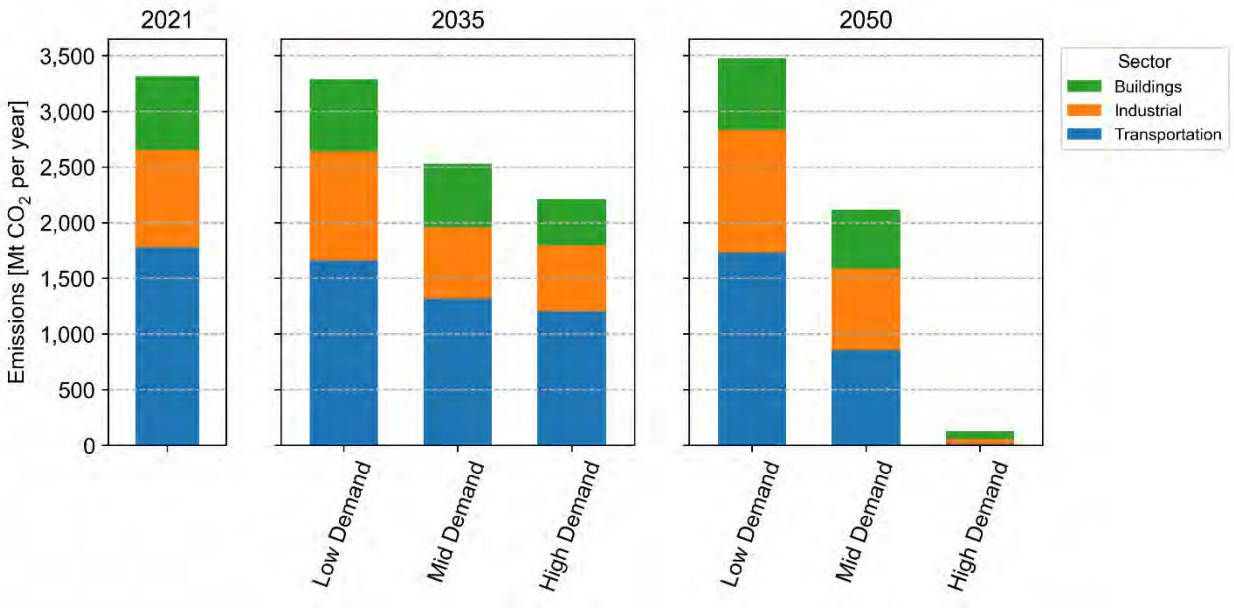


Figure A-4. End-use emissions for the three electricity demand cases

A.5 Climate Change Sensitivity

By default, ReEDS uses historical weather data for load and VRE generation profiles. Because future weather—and associated electricity demand patterns and generation performance—will likely differ from historical weather, a "Climate Change" case with a different set of assumptions is included as a sensitivity.

For this sensitivity, climate-change-impacted load and generation profiles were created from Super-Resolution for Renewable Energy Resource Data with Climate Change Impacts (Sup3rCC) (Buster et al. 2023). The Sup3rCC data are based on global climate model (GCM) data and use generative machine learning models to represent realistic spatiotemporal variability in wind, solar, and load profiles at a nominal 4-km hourly resolution. The Sup3rCC data used in this project are based on the climate model MRI-ESM-2.0 for the SSP5 Climate Change scenario with a climate forcing of 8.5 W/m^2 (Yukimoto et al. 2019). The projected weather data for 7 years (2050–2056) from this scenario are applied to all model years.[48]

Wind and solar PV generation profiles are created using the reV model with the Sup3rCC weather inputs and the same technology assumptions as used in ReEDS (Lopez et al. 2024). The climate-impacted load profiles are created using regression models that establish a relationship between state-level subsector loads (e.g., residential cooling loads for Colorado) and population-weighted hourly meteorological variables (e.g., air temperature, humidity, and irradiance). The regression models were trained on meteorological years 2007–2012 and validated in 2013. The validation results show low bias error, including during peak load hours, and demonstrate the

[48] In other words, the weather forecasted for 2050–2056 is applied to load, wind, and solar PV generation in all model years from 2020 to 2050. This is justified given the long-lived nature of most power system assets and the uncertainties with long-term load forecasts.

models' ability to extrapolate peak loads with nonhistorical temperature inputs (necessary to explore the impacts of climate change on high-stress events).

The climate-impacted load data show an increase in spring and fall demand during high-load periods, especially in the Southeast and the Pacific Northwest because of more frequent and intense heat events (Figure A-5). Summer peak loads generally increase within a state by 2%–8% in magnitude although there is significant spatial variability with some states exhibiting small decreases in load whereas others exhibit increases of up to 14%. Winter peak loads are highly dependent on weather year and region with most states in the East exhibiting a decrease in peak load and other states in the West exhibiting a slight increase in peak load. Because of the local nature of weather events that drive peak load events, the change in coincident peak load tends to decrease with larger spatial aggregations. For example, the coincident peak load across the contiguous United States increases only by 2%. The changes in peak load discussed here are based on isolated effects of weather. Load from both historical and future weather in these comparisons is based on end-use sector (i.e., electrification) assumptions from the 2050 model year in the High-Demand scenario. The impact of climate change on demand profiles is typically smaller in earlier years and for the lower electrification scenarios.

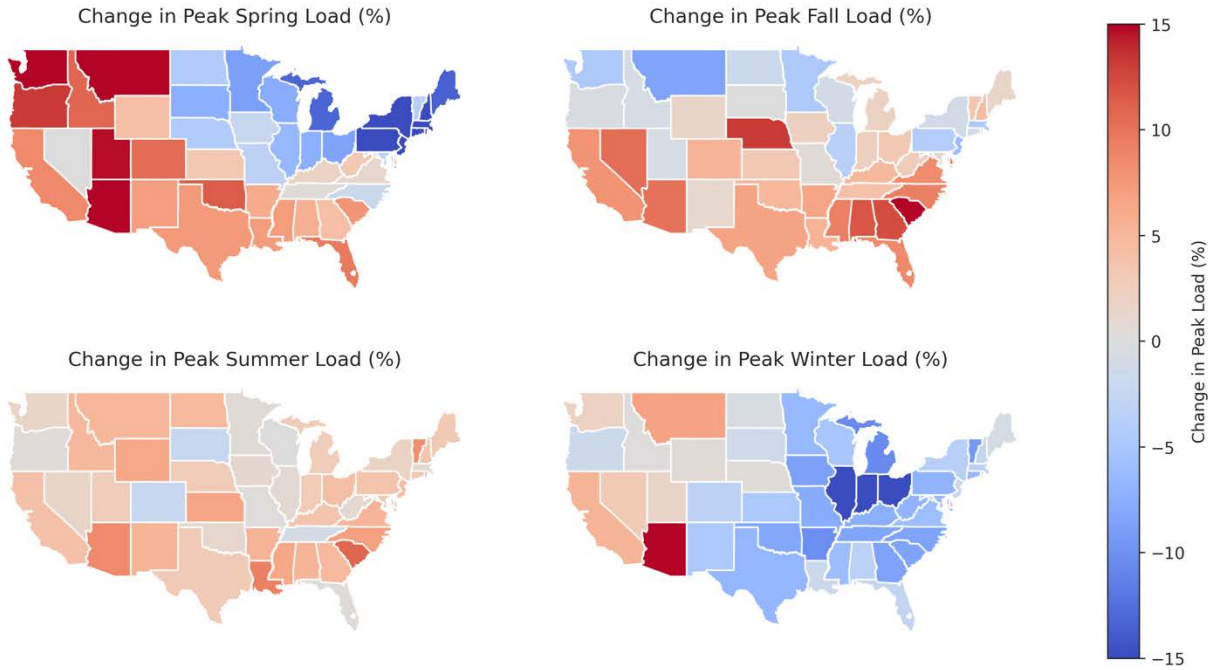


Figure A-5. Changes in seasonal all-sector peak load from historical weather (2007–2013) to future weather impacted by climate change (2050–2056)

The differences are based on the maximum hourly demand for each season across all 7 future weather years relative to the maximum during the 7 historical-weather-year period. This comparison is for the High-Demand case for the 2050 model year, which includes significant electrification.

The climate model and scenario used here do not project significant changes in renewable energy generation. Other GCMs have found larger changes to wind resources that could impact net load profiles and outcomes modeled (Martinez and Iglesias 2022). The Sup3rCC data used here are based on only 7 years (2050–2056) from a single climate model. Additional weather years would better represent the uncertainty from interannual variability. Alternative GCMs and scenarios would also yield different outcomes. Finally, because Sup3rCC is based on GCM data, it does not represent many important meteorological phenomena such as wildfires and hurricanes. Future work will study uncertainty from additional weather years, GCMs, and climate scenarios.

In addition to changes to demand, wind, and solar generation, the Climate Change sensitivity also includes adjustments to the potential contribution of hydropower, thermal resources, and transmission. Specifically, simple derate factors are applied to the summer capacity of these resources during both “representative” and “stress” periods modeled in ReEDS to represent various phenomena that could reduce the performance of these technologies or to reduce planners’ confidence in these resources for meeting system adequacy requirements.

To represent potential climate change impacts on hydropower resources, reservoir hydropower capacity is reduced by 20% during the modeled stress periods. This 20% reduction is applied for the 2050 model year with a simple linear ramp to this ultimate value starting in 2025. Derates are applied uniformly in all regions. The 20% value approximates impacts estimated by Turner et al. (2022) for hydropower facilities in WECC.

To represent climate change impacts on thermal cooling units, all available thermal generation capacity is derated during summer periods by 15% in 2050 with the same linear ramp starting from 2025. For thermal power plants, ReEDS uses summer capacity ratings, as reported for the EIA National Energy Modeling Systems data and supplemented with EIA form-860 data, for all nonwinter seasons. Summer capacity ratings are typically lower than winter or nameplate capacities, and the derate applied here is on top of this reduction as a proxy for higher temperatures and lower cooling water availability compared to historical summer periods.[49] This value is based on a 15% reduction in WECC thermal capacity driven by cooling water availability (Voisin et al. 2017). In addition, data from Electric Reliability Council of Texas (ERCOT) imply an 11% reduction in thermal capacity during summer (Electric Reliability Council of Texas 2022).

To represent climate change impacts on transmission, summer transmission capacity is derated by 5% by 2050 using a linear ramp starting from 2025. In ReEDS the transmission capacities are already based on summer ratings, so this reduction would be incremental to those driven by higher-than-historical temperatures during summer.

[49] Winter capacities are used for winter periods in ReEDS. All reported capacities in this study reflect summer ratings.

The 5% value is within the range estimated by Bartos et al. (2016). Another study for California suggests a 7% reduction (Sathaye et al. 2011).

Climate change impacts on demand, generation resources, and transmission are complex with significant uncertainties. Given the simple representation and proxy assumptions applied here, the results from the climate change sensitivity cases should be interpreted as indicative rather than definitive.

Appendix B. Integrated Capacity Expansion and Resource Adequacy Modeling

The Regional Energy Deployment System (ReEDS) and Probabilistic Resource Adequacy Suite (PRAS) models are operated in concert to analyze the scenarios presented in this chapter. Both models are summarized in Section 2.1. Appendix A provides more details about ReEDS; this appendix provides additional detail about PRAS and discusses how the models are integrated to help ensure the future portfolios analyzed are resource adequate. Mai et al. (forthcoming) provide further explanation about the combined modeling. Documentation for an earlier version of the PRAS model can be found in Stephen (2021), and the model is available open source.[50]

B.1 What Is PRAS?

PRAS is a probabilistic tool that simulates thermal generator outages and economic dispatch over a multiyear period to generate adequacy metrics for power system portfolios. It covers the same geographic extent (contiguous United States) with the same zonal spatial resolution (134 zones) as ReEDS. As described next, most of the data used in PRAS are passed directly from ReEDS. For example, hourly wind, solar, and load profiles are the same as those used in ReEDS. For this analysis, PRAS executes hourly simulations over 7 weather years (2007–2013).

PRAS models transmission in the same zonal manner as ReEDS and does not represent transmission outages. For thermal generators, the total capacity in each zone is disaggregated into individual units to facilitate the Monte Carlo assessment performed by PRAS. This disaggregation process uses data for existing units from the EIA National Energy Modeling System (NEMS) model (EIA 2023b) and, for new capacity, typical unit sizes from the 2023 Annual Technology Baseline (National Renewable Energy Laboratory 2023). Outage rates for thermal generators and storage are based on 2014–2018 data from the North American Electric Reliability Corporation (NERC) Generating Availability Data System (GADS) (NERC 2023b).

By using multiple years of hourly renewable energy and load possibilities along with thermal generator and storage outages, PRAS can provide statistical measures about the likelihood of unserved load. Reliability metrics estimated by PRAS include loss of load probability (LOLP), loss of load expectation (LOLE), and expected unserved energy (EUE). This can be used to assess system adequacy as well as when and where the system is likely to be stressed.

B.2 Integrated ReEDS-PRAS process

Figure B-1 shows how ReEDS and PRAS are used together. For a given solve period (e.g., 2035), ReEDS develops an initial system design that is passed on to PRAS. PRAS is then executed to estimate the total normalized expected unserved energy (NEUE)—where the normalization divides EUE by total contiguous U.S. load—and to

[50] https://www.nrel.gov/analysis/pras.html

identify the days of highest system stress (highest EUE). If a specified NEUE target is met, ReEDS proceeds to the next solve period (e.g., 2040). If the target is not met, ReEDS re-solves for the same solve period but with additional stress periods considered and the iterative process repeats. To limit computational runtimes, an iteration limit is also imposed, where ReEDS proceeds to the next solve period despite not meeting NEUE target; however, this seldom occurs in the scenarios.

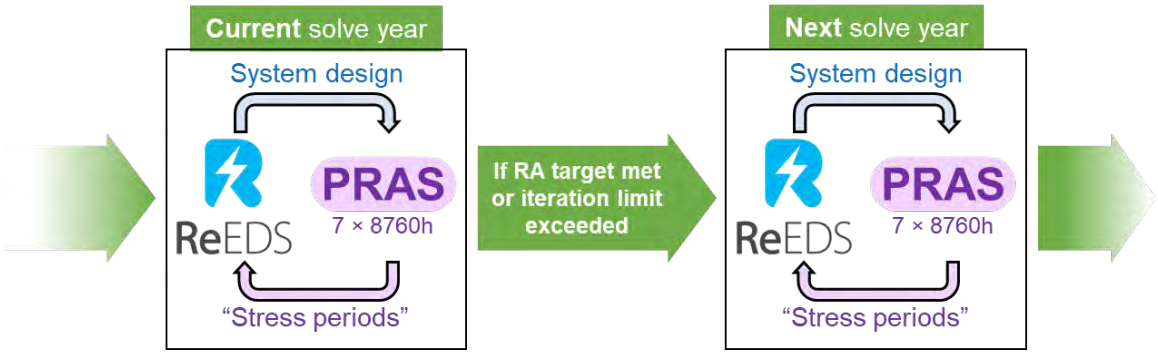


Figure B-1. Integrated capacity expansion and resource adequacy modeling

ReEDS models up to 30 stress periods, which are the periods with highest EUE as estimated by PRAS.[51] During the stress periods, ReEDS models dispatch in largely the same manner as the "representative periods." Important differences are that demand during these periods is elevated by the planning reserve margin (12%–18%), which is based on reference reserve margins from the 2021 NERC Long-Term Reliability Assessment (NERC 2021). Differences between this approach and a traditional planning reserve margin approach—including how it better addresses systems with higher VRE and transmission exchanges—are discussed by Mai et al. (forthcoming).

B.3 Planning Threshold

There are many metrics used to quantify resource adequacy (RA), with associated target reliability levels used in system planning. Most power systems in the United States quantify RA using LOLE, with a target of LOLE ≤1 day in 10 years (NERC 2023a). LOLE does not capture the severity of loss of load events; a power system that experiences a 1-day interconnection-wide blackout every 10 years and a power system that curtails 1 GW of industrial load on 1 day in 10 years would both satisfy the 1-in-10 LOLE target (Stenclik et al. 2021; Stephen et al. 2022). The EUE, measured in MWh, and load-normalized EUE (NEUE), measured as a percent or parts per million (ppm), metrics are volumetric rather than event-based, so the 1-blackout-in-10-years system would have much higher EUE and NEUE (and thus lower reliability) than the 1-industrial-load-shed-event-in-10-years system. Though NEUE-based system planning based has yet to become widespread, systems that do use NEUE-based planning tend to use NEUE targets in the range of 10 to 30 ppm (Alberta Electricity system Operator 2017; Electric Power Research Institute 2024; NERC 2024). In this study, the NEUE metric is used with a conservatively set threshold of 10 ppm. For context, if load were equally distributed across a year, 10 ppm would be equivalent to 5 minutes of complete

[51] The model is seeded with the highest demand period as a stress period to start.

load shedding (blackout) per year, 9% load shedding spread over a one-hour period, or 0.4% load shedding spread over a 24-hour day.

B.4 Caveats

The integrated ReEDS-PRAS formulation used here attempts to incorporate many of the practices recommended for evaluating systems with significant deployment of renewable energy, storage, and transmission (Stenclik 2023). However, as with any modeling analysis, there are limitations—and this section describes important caveats.

- **Reliability target.** The NEUE reliability metric is used in the scenario modeling for the reasons described previously, but this metric is not yet commonly adopted in practice. Another reliability metric could result in different outcomes. Moreover, because there are trade-offs between cost and reliability, different portfolio outcomes could result if the NEUE threshold assumption of 10 ppm were changed. The 10-ppm threshold is an upper bound in the model implementation; thus, the level of reliability can vary between 0 and 10 ppm across scenarios. Regional NEUE thresholds would also yield outcomes different from the national threshold used here.
- **Weather years.** Most scenarios consider 7 years of historical (2007–2013) weather in the PRAS modeling. Additional weather years would enable a more robust assessment of RA. Future weather conditions could also change and affect demand profiles and the contributions from weather-dependent resources.[52] The Climate Change sensitivity provides one sample of impacts from future weather (see Appendix A).
- **Outages.** PRAS simulates thermal generator and storage outages, but in the modeling these outage rates do not vary with time or weather conditions. In reality, thermal outages are correlated with extreme temperatures (S. Murphy, Sowell, and Apt 2019). PRAS also does not represent transmission outages, which could be a higher source of system risk in the scenarios with significantly expanded transmission.
- **Demand response.** The versions of ReEDS and PRAS used for this study do not include demand response. Demand response is used in some systems to provide RA capacity—e.g., 1.9 GW in CAISO in 2022, roughly 3%–4% of total RA capacity (CAISO 2023b). All unserved energy is included in the NEUE values discussed here, but in practice some of this unserved energy would be served by appropriately compensated demand response and would not be considered to contribute to “dropped load” events. If demand response for RA were included in the simulations, the resulting NEUE would be reduced.

[52] The impact of future electrification on demand profiles are reflected in the scenarios, but demand from the use of these new electrified end uses is based on historical weather in most scenarios.

Appendix C. Technology Cost Assumptions

The Regional Energy Deployment System (ReEDS) models a large suite of technologies, including electricity generation technologies, energy storage technologies, CO_2 capture and storage, and hydrogen-producing technologies.

C.1 Supply-Side Technologies

Table C-1 lists the electricity generation and storage technologies available in ReEDS and outlines which technologies are deployable under default assumptions in this study and which are included and excluded in various sensitivity cases.

Table C-1. Technologies Modeled in ReEDS

Technology	Expansion Allowed in Core Scenario	Included Sensitivity Cases	Excluded Sensitivity Cases
4-Hr Battery[a]	Yes		
8-Hr Battery[a]	Yes		
Bioenergy with CCS (BECCS)	Yes		
Biopower	Yes		
Concentrating Solar Power (CSP)	Yes		
Geothermal[b]	Yes		
Hydropower[b]	Yes		
Natural Gas Combined Cycle (NG-CC)	Yes		
Natural Gas Combustion Turbine (NG-CT)	Yes		
Land-Based Wind[b]	Yes		
Offshore Wind[b]	Yes		
Pumped Hydropower[b]	Yes		
Utility-Scale Solar PV[b]	Yes		
Coal + Carbon Capture and Storage (Coal-CCS)[d]	Yes		No CCS; No H_2 or CCS
Hydrogen Combustion Turbine (H_2-CT)[d]	Yes		No H_2; No H_2 or CCS; No H_2 or new nuclear

Technology	Expansion Allowed in Core Scenario	Included Sensitivity Cases	Excluded Sensitivity Cases
Technology	**Expansion Allowed in Core Scenario**	**Included Sensitivity Cases**	**Excluded Sensitivity Cases**
Natural Gas Combined Cycle with CCS (NG-CC-CCS)[d]	Yes		No CCS; No H_2 or CCS
Nuclear	Yes		No H_2 or new nuclear
Nuclear Small Modular Reactor (SMR)	No	+Nuclear SMR + DAC	
Coal[c]	No, existing capacity only		
Landfill Gas[c]	No, existing capacity only		
Oil-Gas-Steam[c]	No, existing capacity only		
Distributed PV[e]	Expansion is exogenously specified		

[a] ReEDS can model 2-, 4-, 6-, 8-, and 10-hour batteries, but only the 4-hour and 8-hour battery durations are modeled in this study to reduce computation time while allowing for both shorter-duration and longer-duration storage options.

[b] Plants of these types are modeled with a supply curve because these technologies have site-specific characteristics and multiple technology configurations. For land-based wind, offshore wind, and utility-scale solar PV, these supply curves and generation profiles are from the reV model.

[c] Existing plants of these types are included, but expanded capacity is not allowed in this analysis.

[d] Plants of these types can be greenfield builds or retrofits. More detail on retrofits can be found in Appendix C.2.

[e] Distributed PV deployment is exogenously specified based on simulations from NREL's Distributed Generation Market Demand (dGen) model (Sigrin et al. 2016). The same distributed PV projection featuring 130 GW of distributed PV capacity by 2035 is used for all scenarios and based on the Standard Scenarios 2023 Mid-case (Gagnon et al. 2024). Distributed PV cannot be curtailed in ReEDS.

Most scenarios use technology cost and performance assumptions from the 2023 ATB Moderate case. Capital, fixed operation and maintenance, and variable operation and maintenance cost data for the core scenarios are shown in Table C-2, Table C-3, and Table C-4, respectively. Costs for hydropower and geothermal options vary significantly by technology type and location and are therefore not shown in the tables. These costs are based on DOE's Hydropower Vision Report (DOE 2016) and the 2023 ATB (National Renewable Energy Laboratory 2023) for the two technologies, respectively. Other technology assumptions (e.g., heat rate, capacity factor improvements), as well as more conservative or advanced cost assumptions used in the cost sensitivity cases, can be found in the ATB.

Table C-2. Overnight Capital Costs ($/kW) in the Core Scenarios

Technology	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
4-Hr Battery	1,551	1,300	1,199	1,099	999	899
8-Hr Battery	2,790	2,282	2,093	1904	1,715	1,528
BECCS[a]	7,373	7,259	7,155	7,051	6,947	6,843
Coal-CCS	4,943	4,641	4,339	4,102	3,866	3,629
CSP[b]	4,529	3,658	3,528	3,397	3,266	3,136
NG-CC	1,174	1,122	1,070	1026	982	938
NG-CC-CCS	2,424	2,179	1934	1,823	1,713	1,602
NG-CT	1,057	1,014	971	928	885	843
H_2-CT[c]	1,088	1,044	1,000	956	912	868
Land-Based Wind	1,194	1,083	1,029	976	923	869
Nuclear	6,925	6,603	6,384	6,159	5,947	5,696
Nuclear SMR	7,563	7,213	6,974	6,729	6,500	6,227
Offshore Wind, Fixed-Bottom[d]	2,228	2048	1937	1,856	1,793	1,740
Offshore Wind, Floating Platform[d]	3,329	3,071	2,912	2,796	2,705	2,630
Utility-Scale Solar PV	1,300	1,082	864	795	727	659

[a] Costs shown assume a 90% emissions capture rate. BECCS cost and performance values are from Young (2020).

[b] Costs shown for CSP assume 8 hours of thermal energy storage (TES). ReEDS models four classes of CSP technologies, including various durations of TES.

[c] Hydrogen combustion turbine capital costs are not included in the ATB. Assumed costs for new H_2-CTs are 3% greater than for new NG-CTs (Denholm et al. 2022).

[d] Offshore wind costs shown for fixed-bottom technologies are for Wind Resource Class 3, and those shown for floating platform technologies are for Wind Resource Class 10. There are seven classes for each offshore wind technology in the ATB, and each class has different capital costs. See the 2023 ATB for more details (National Renewable Energy Laboratory 2023).

Table C-3. Fixed Operation and Maintenance Costs in $/(kW-year) in the Core Scenarios

Technology	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
4-Hr Battery	38.8	32.5	30.0	27.5	25.0	22.5
8-Hr Battery	69.8	57.1	52.3	47.6	42.9	38.2
BECCS	217	217	217	217	217	217
Coal-CCS	129	122	115	110	104	98.7
CSP	47.1	39.7	39.7	39.7	39.7	39.7
NG-CC	32.6	31.0	29.3	28.2	27.1	26.0
NG-CC-CCS	64.9	58.3	51.7	49.0	46.3	43.6
NG-CT	25.5	24.7	24.1	23.3	22.6	21.9
H_2-CT	23.7	23.7	23.7	23.7	23.7	23.7
Land-Based Wind	28.8	27.0	26.1	25.2	24.2	23.3
Nuclear	164	164	164	164	164	164
Nuclear SMR	128	128	128	128	128	128
Offshore Wind, Fixed-Bottom	107	97.6	91.3	86.5	82.7	79.5
Offshore Wind, Floating Platform	80.3	73.8	69.4	66.1	63.4	61.2
Utility-Scale Solar PV	22.1	19.4	16.8	16.0	15.3	14.6

Table C-4. Variable Operations and Maintenance Costs in $/MWh in the Core Scenarios

Technology	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
4-Hr Battery	0	0	0	0	0	0
8-Hr Battery	0	0	0	0	0	0
BECCS	22.3	22.3	22.3	22.3	22.3	22.3
Coal-CCS	15.4	14.7	14.0	13.7	13.5	13.2
CSP	2.6	2.3	2.3	2.3	2.3	2.3
NG-CC	2.1	2.0	1.9	1.9	1.8	1.7
NG-CC-CCS	4.8	4.4	4.0	3.9	3.7	3.6
NG-CT	7.0	7.0	7.0	7.0	7.0	7.0
H_2-CT	5.6	5.6	5.6	5.6	5.6	5.6
Land-Based Wind	0	0	0	0	0	0
Nuclear	2.7	2.7	2.7	2.7	2.7	2.7
Nuclear SMR	3.4	3.4	3.4	3.4	3.4	3.4
Offshore Wind, Fixed-Bottom	0	0	0	0	0	0
Offshore Wind, Floating Platform	0	0	0	0	0	0
Utility-Scale Solar PV	0	0	0	0	0	0

C.2 Retrofits With CCS

Existing fossil-fuel-fired capacity is allowed to retrofit with carbon capture and storage. Retrofits are allowed starting in 2030. Capital costs for retrofits and capacity derates are based on data from EIA NEMS assumptions (EIA 2023b) as described in Table C-5.

Table C-5. Retrofit Assumptions for Technologies in ReEDS

Original Technology	Retrofit Technology	Capital Costs	Capacity Derate
Coal	Coal-CCS	Uses NEMS retrofit capital cost data when available for existing plants. Otherwise, retrofit costs are from ATB where retrofit costs start at $3,100/kW in 2023 and decrease to $1,600/kW by 2050 (National Renewable Energy Laboratory 2023).	Uses NEMS heat rate data when available for existing plants to approximate capacity derate. Otherwise assumes a 29% derate after retrofitting.
NG-CC	NG-CC-CCS	Uses NEMS retrofit capital cost data when available for existing plants. Otherwise, retrofit costs are from ATB where retrofit costs start at $1,690/kW in 2023 and decrease to $1,010/kW by 2050 (National Renewable Energy Laboratory 2023).	Uses NEMS heat rate data when available for existing plants to approximate capacity derate. Otherwise assumes a 14% capacity derate after retrofitting.

C.3 Negative Emissions Technologies

ReEDS models two negative emissions technologies: bioenergy with CCS (BECCS) and direct air capture (DAC). BECCS is enabled by default in these scenarios and allowed to expand. The cost assumptions for BECCS are shown in Appendix C.1 because BECCS is also a supply-side technology. BECCS is assumed to have a 90% capture rare and an emissions rate of -0.060 metric tons CO_2 per MMBtu. DAC is turned off by default but enabled in the +Nuclear SMR + DAC scenario. The assumed levelized cost of DAC is between $300 and $400 per metric ton of CO_2 captured and sequestered based on Brown et al. (forthcoming).

The national CO_2(e) emissions constraint in ReEDS is modeled on a net basis, meaning negative emissions technologies can offset (positive) emissions to reach the desired target level. However, offsets of emissions are allowed only from fossil with CCS. Based on this definition, generation from fossil plants without CCS is not allowed when the requirement is net zero (e.g., after 2035 under the 100% by 2035 scenarios or after 2045 under the 90% by 2035 scenarios).

C.4 Financing and Retirement Assumptions

The economic lifetime assumptions for various technologies are shown in Table C-6. Most generators are assumed to have a 20-year economic lifetime whereas 15 years is assumed for batteries and electrolyzers and 40 years for transmission.

There are multiple ways plants can retire:

- **Announced retirements.** Plants that have announced their retirement date (EIA 2023b) are retired during that year.
- **Age-based retirements.** Plants must retire on or before their maximum age as shown in Table C-6. Utility-scale solar PV, distributed scale solar PV, land-based wind, and offshore wind can be repowered—with the associated new plant capital cost but without the need for new interconnection costs—once they reach their maximum age.
- **Endogenous retirements.** The model decides to retire capacity to avoid ongoing operation and maintenance and fuel costs if the plant does not receive sufficient value or revenue in the model. This is allowed only for fossil fuel plants.
- **Policy-based retirements.** Certain technologies in ReEDS regions and model years are forced to retire because of policy requirements.

Table C-6. Financing and Maximum Age Assumptions for Technologies in ReEDS

Technology	Economic Lifetime (years)	Maximum Age (years)
Hydropower	20	*
(Non-hydro) Renewable energy (wind, solar PV, geothermal, CSP)	20	30
Coal (with and without CCS)	20	70
NG-CC (with and without CCS)	20	55
NG-CTs and H_2-CTs	20	55
Nuclear	20	80
Nuclear SMR	20	80
Storage (pumped hydropower)	20	*
Storage (batteries)	15	15
Electrolyzer	15	*
Transmission	40	*

** No maximum age is modeled for these technologies.*

Appendix D. Additional Results

D.1 ReEDS Results for 2035

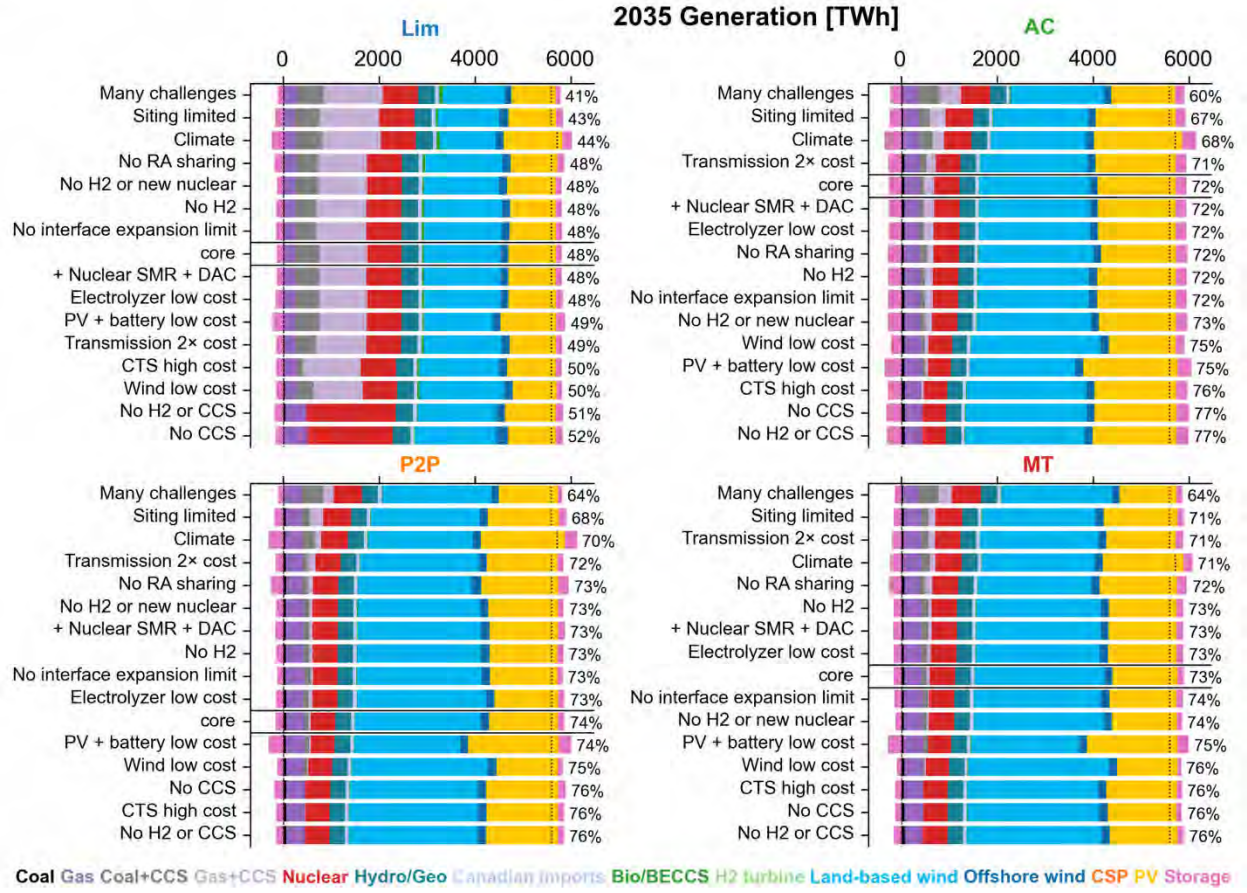


Figure D-1. National generation mix in 2035 with Mid-Demand 90% by 2035 assumptions for each transmission framework and sensitivity case

Within each transmission framework, the sensitivity cases are sorted by 2035 VRE share (indicated by the percentage value to the right of each generation bar). Total generation is greater than end-use demand (vertical dotted line) because of transmission and distribution losses, storage losses, and generation for hydrogen production via electrolyzers. Total storage charging is shown as negative values and discharging as positive values.

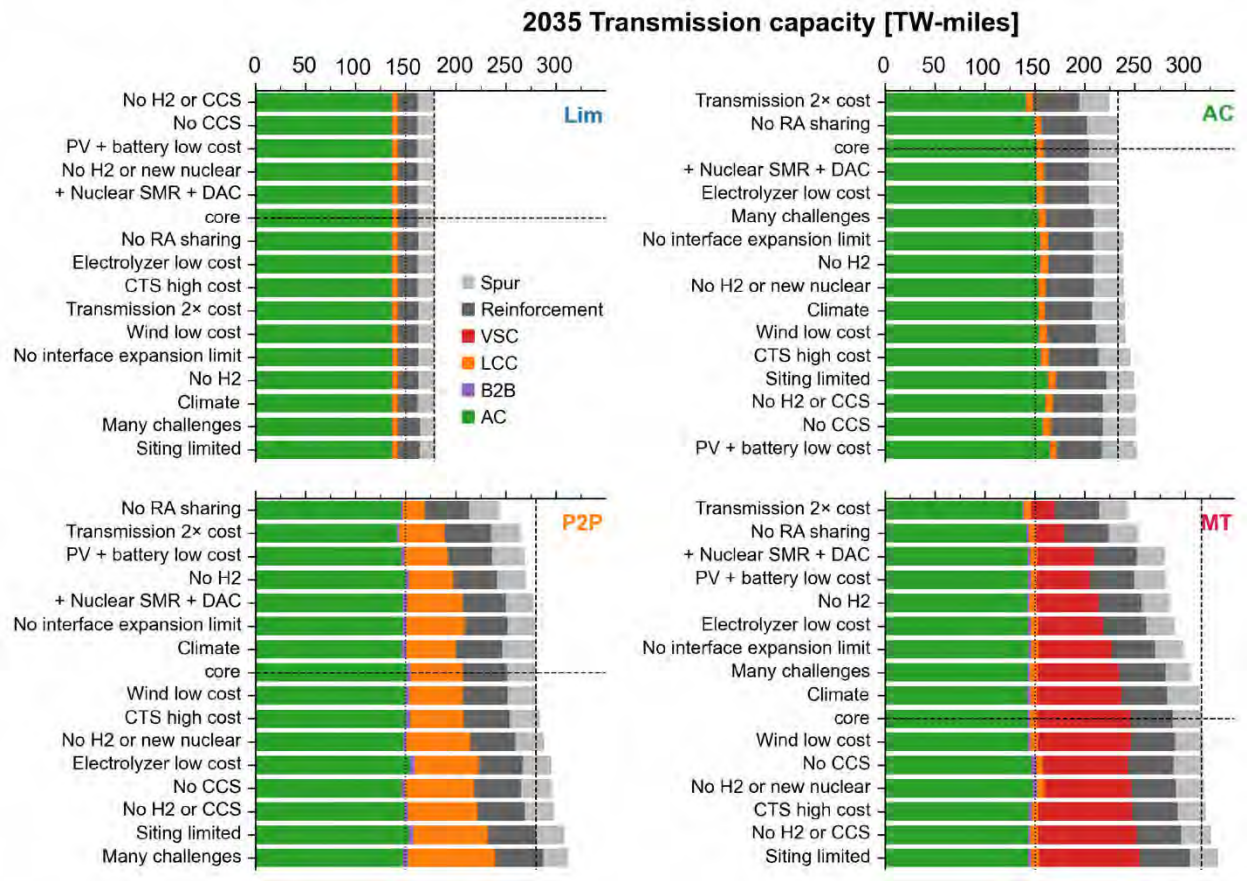


Figure D-2. Transmission capacity in 2035 with Mid-Demand 90% by 2035 assumptions for each transmission framework and sensitivity case

Values for the core scenario for each transmission framework are marked by dashed black lines. Within each transmission framework, sensitivity cases are sorted by total transmission capacity in 2035. The 1.83 TW-mile/year limit on annual transmission additions is binding in all sensitivity cases for the Limited transmission framework, making 2035 transmission capacity the same in all sensitivity cases for this framework.

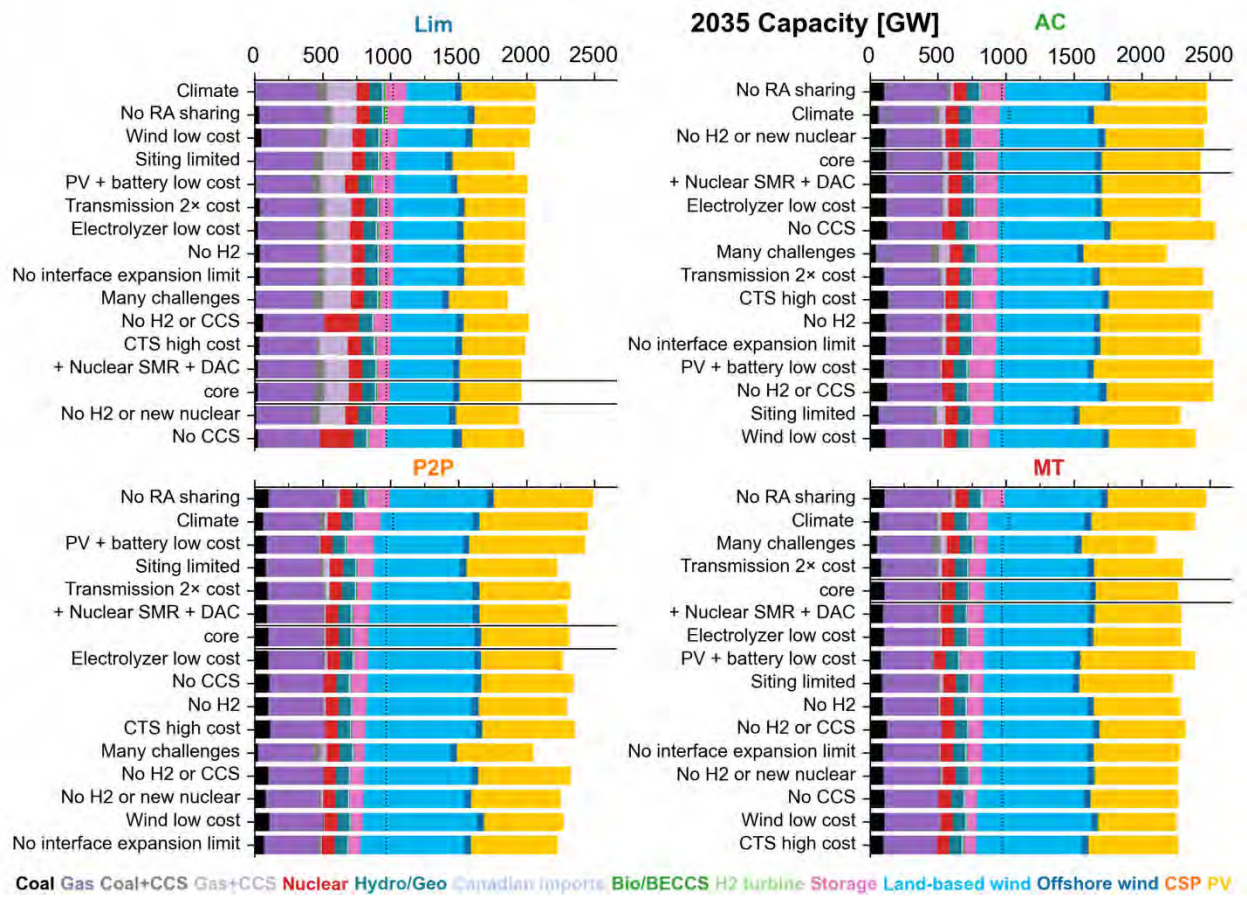


Figure D-3. National capacity mix in 2035 with Mid-Demand 90% by 2035 assumptions for each transmission framework and sensitivity case

Within each transmission framework, the sensitivity cases are sorted by 2035 VRE capacity share. Peak coincident end-use demand is shown as vertical dotted lines.

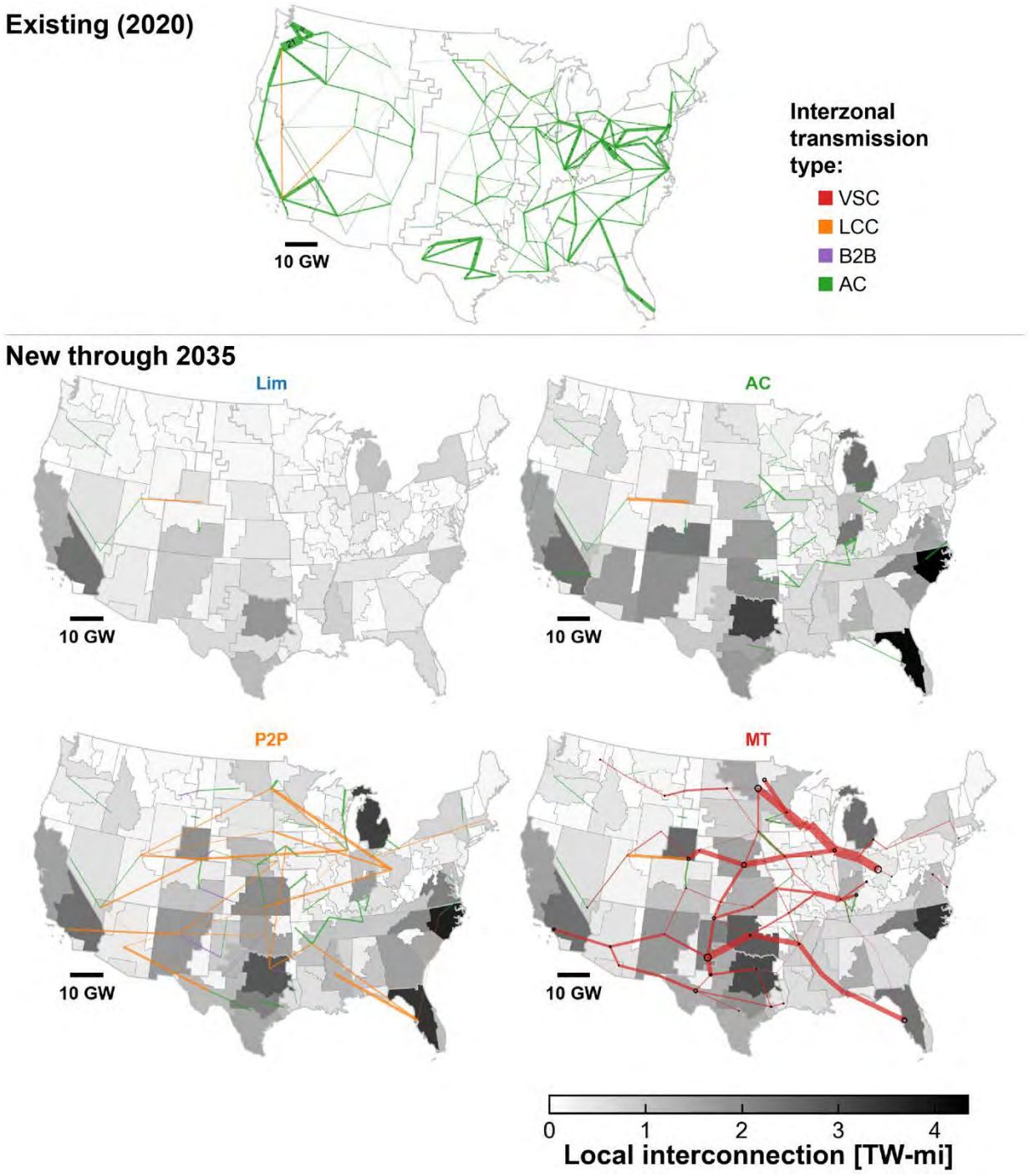


Figure D-4. New local and long-distance transmission through 2035 under Mid-Demand 90% by 2035 assumptions for each of the four transmission frameworks, with existing 2020 long-distance transmission capacity for context (top)

Interface transfer capability is indicated by the thickness of the lines connecting ReEDS zones. Converter capacity in the MT framework is indicated by the diameter of empty black circles, using the same length scale as the interface lines. The depiction of interzonal transmission capacity as straight lines between zone centers is a visual simplification; in practice, the interzonal transfer capacity would be spread across many transmission corridors for each interface.

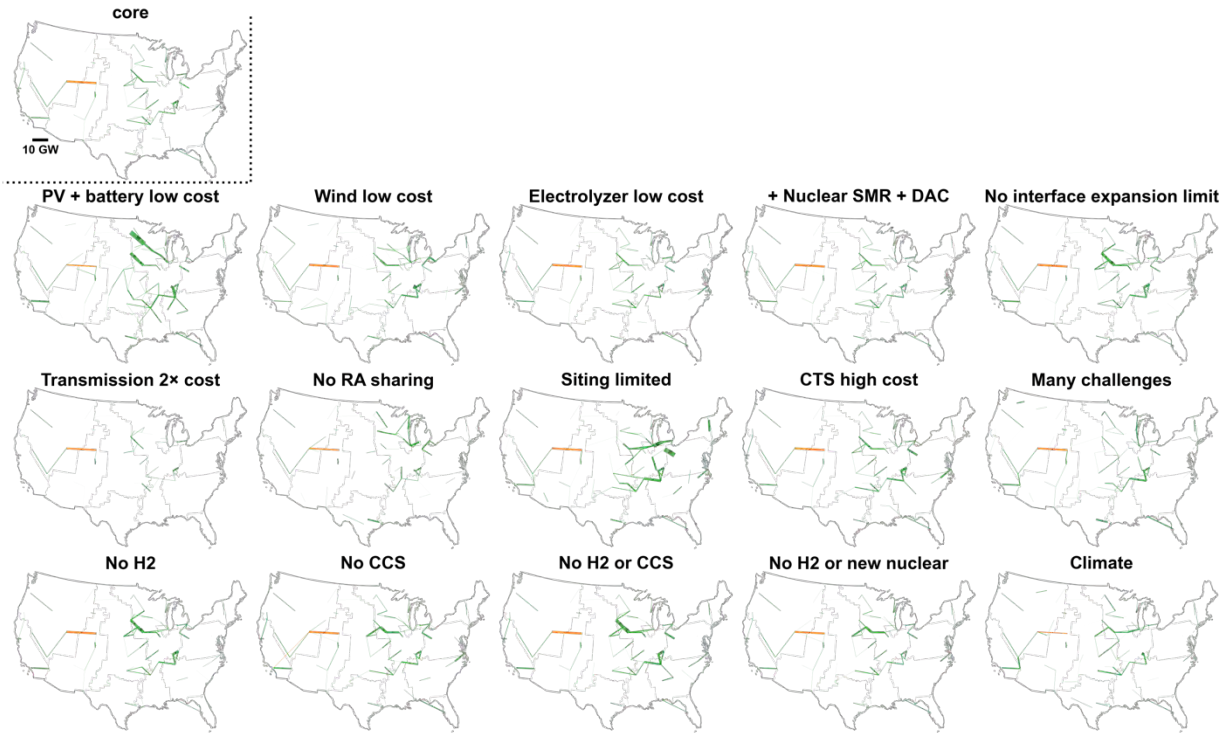


Figure D-5. New long-distance transmission additions through 2050 with Mid-Demand 90% by 2035 assumptions for each sensitivity case under the AC transmission framework

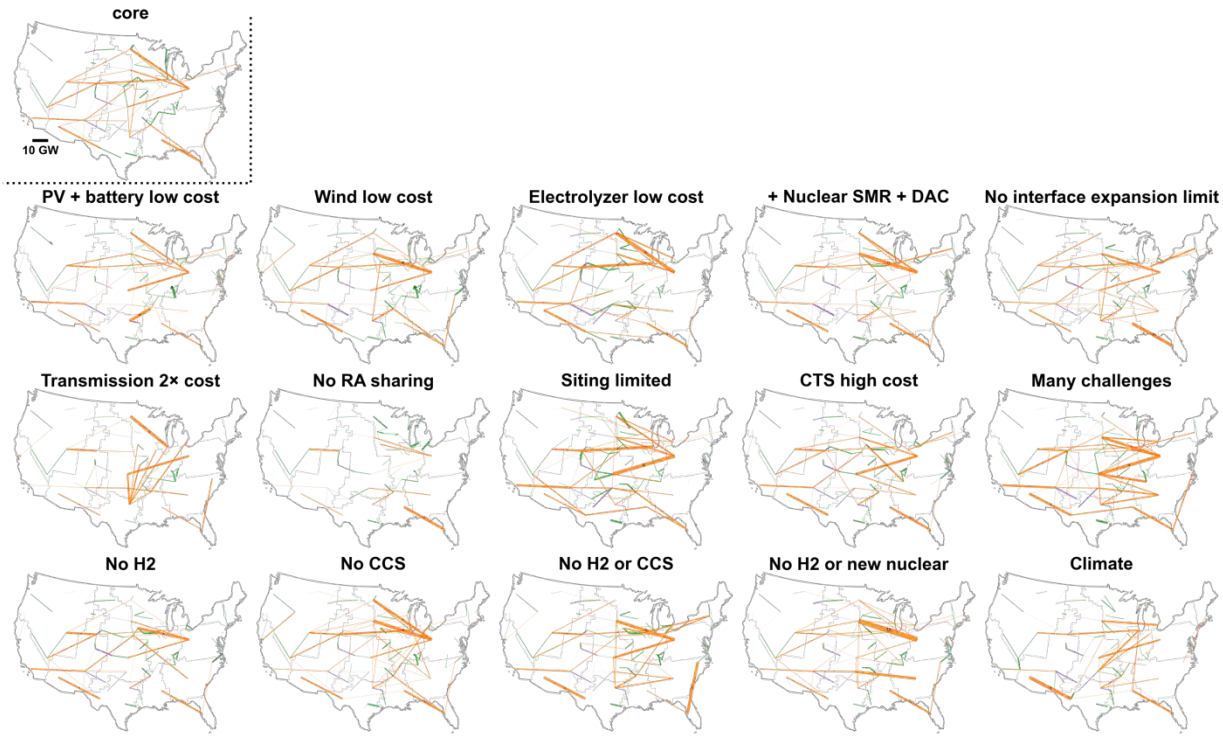


Figure D-6. New long-distance transmission additions through 2050 with Mid-Demand 90% by 2035 assumptions for each sensitivity case under the P2P transmission framework

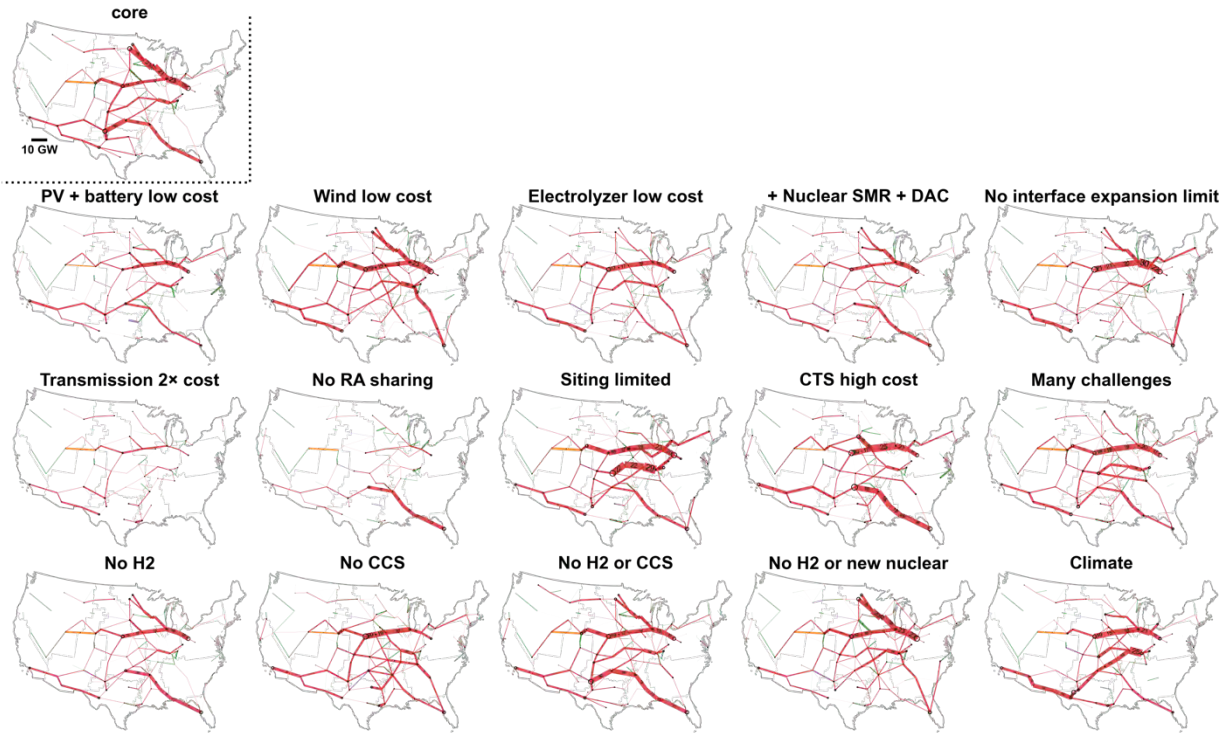


Figure D-7. New long-distance transmission additions through 2050 with Mid-Demand 90% by 2035 assumptions for each sensitivity case under the MT transmission framework

D.2 Additional Capacity Expansion Modeling Results Through 2050

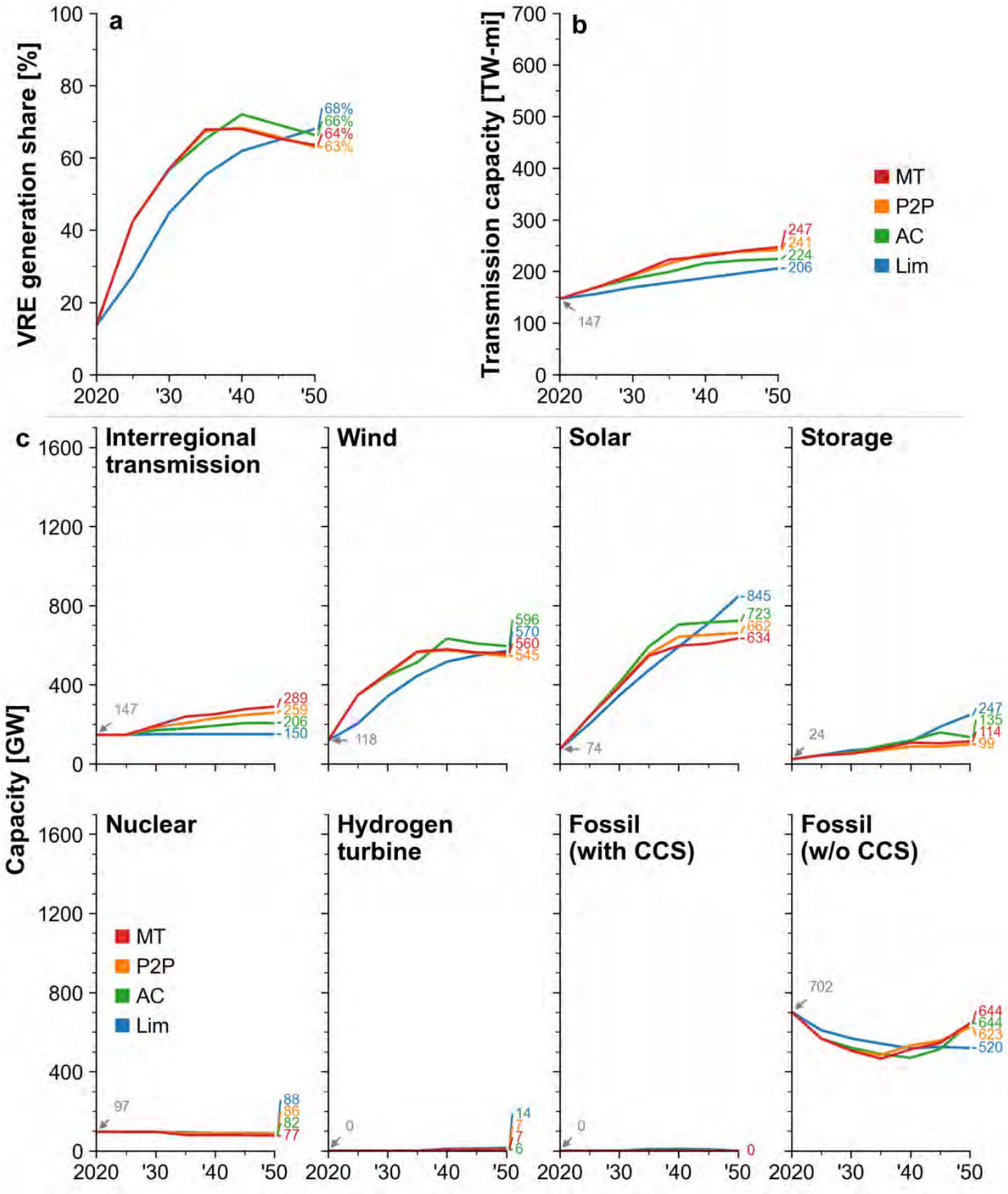


Figure D-8. Trajectories of VRE share (a), transmission capacity (b), and nameplate capacity (c) under Low-Demand Current Policies conditions

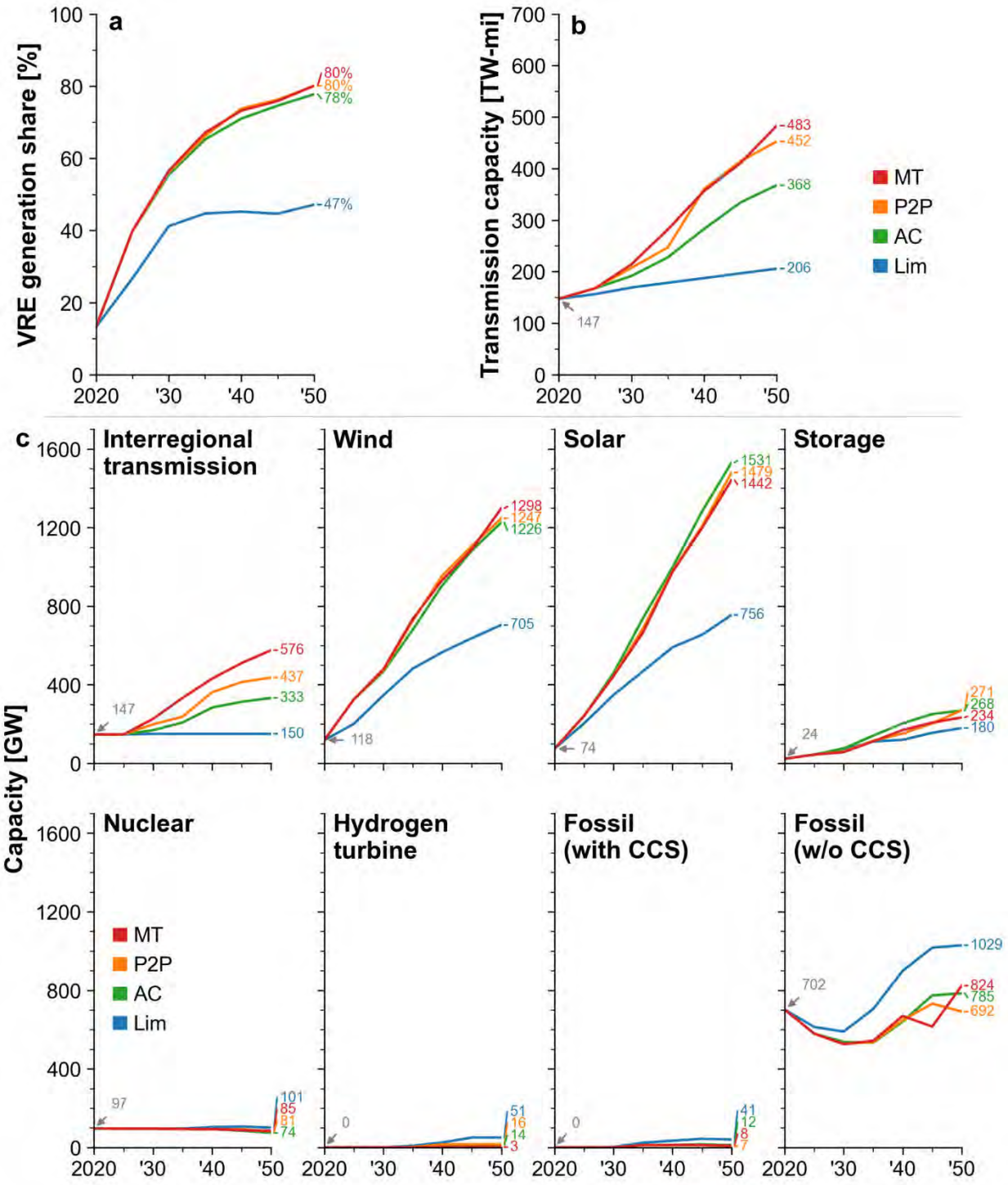


Figure D-9. Trajectories of VRE share (a), transmission capacity (b), and nameplate capacity (c) under High-Demand Current Policies conditions

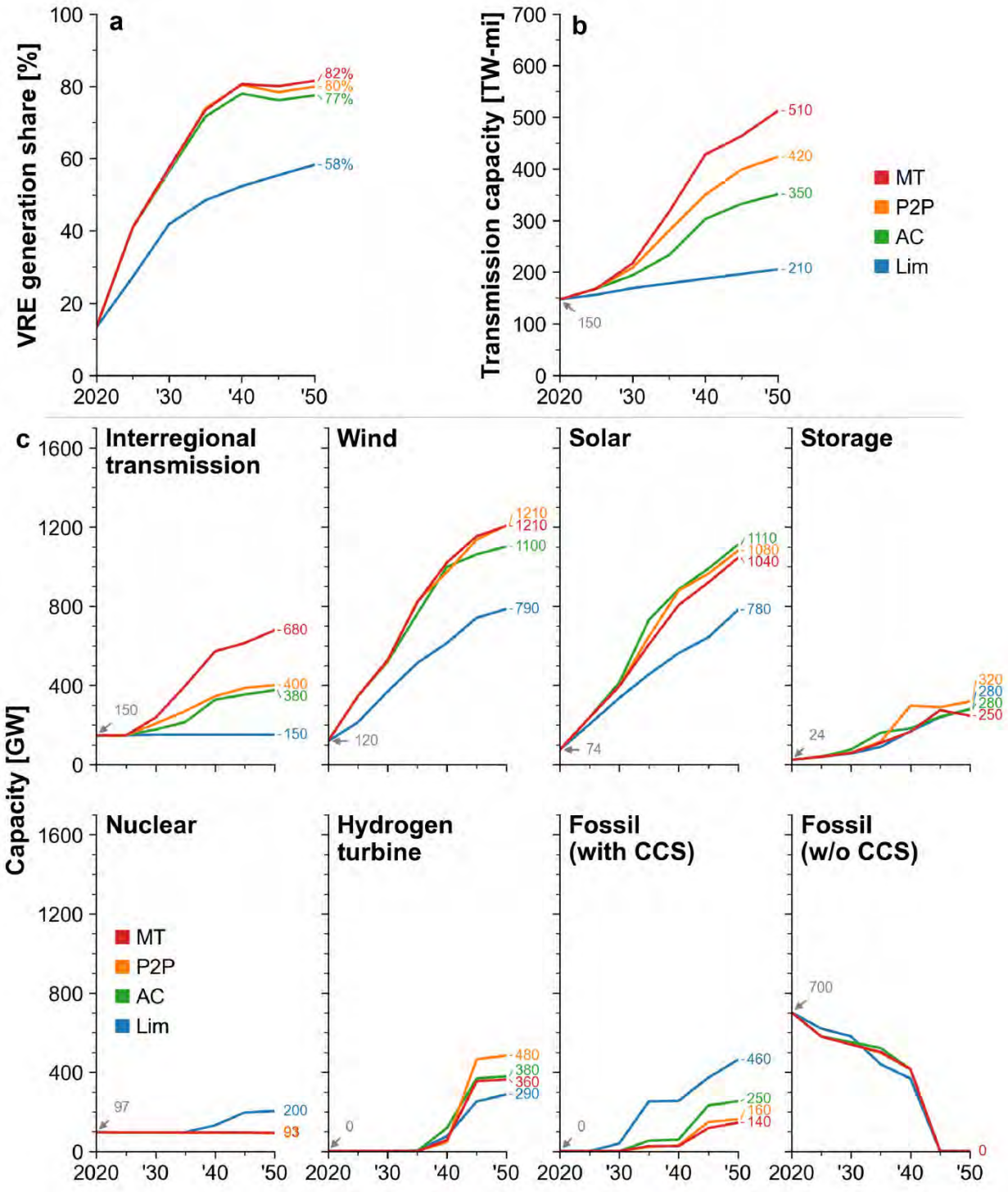


Figure D-10. Trajectories of VRE share (a), transmission capacity (b), and nameplate capacity (c) under Mid-Demand 90% by 2035 conditions

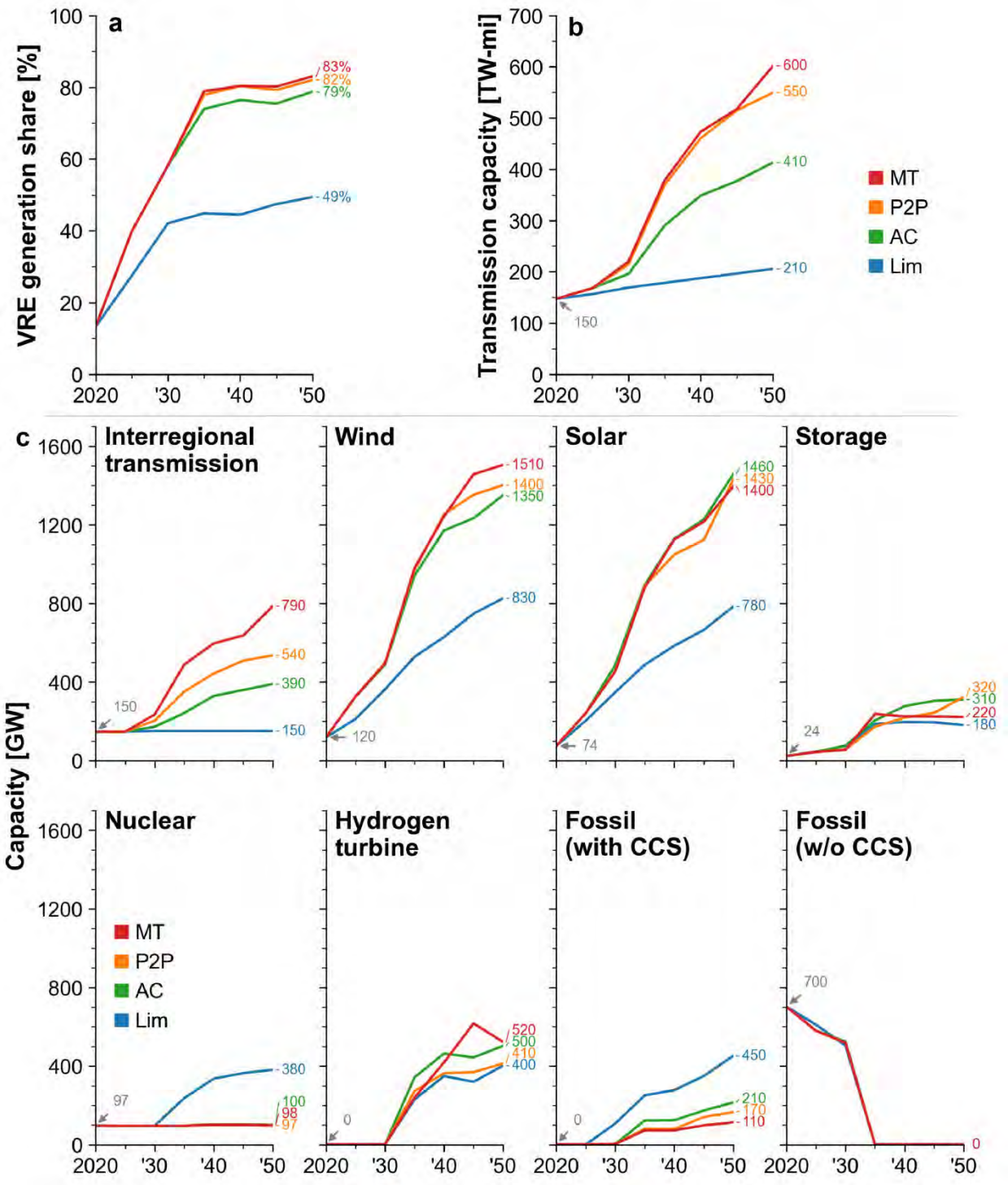


Figure D-11. Trajectories of VRE share (a), transmission capacity (b), and nameplate capacity (c) under High-Demand 100% by 2035 conditions

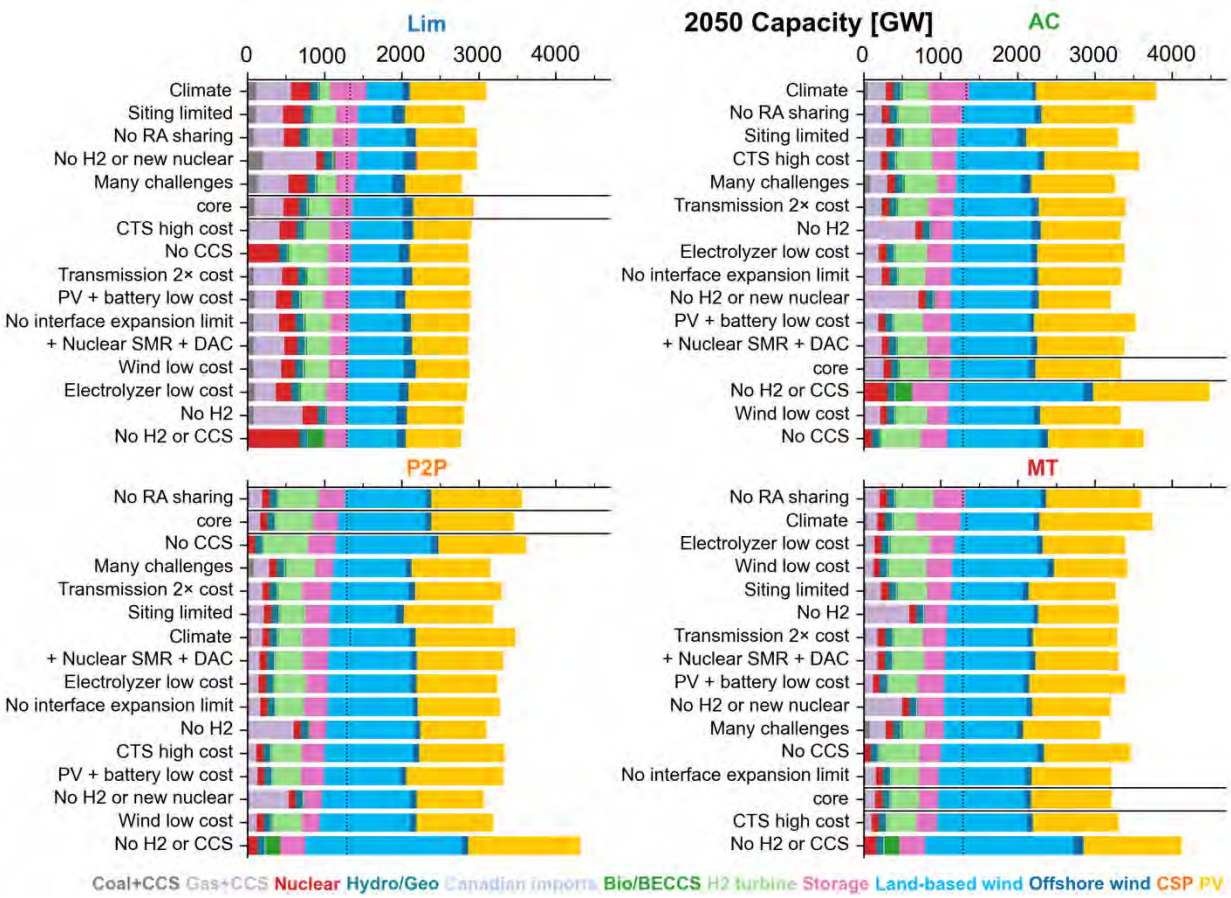


Figure D-12. National capacity mix in 2050 with Mid-Demand 90% by 2035 assumptions for each transmission framework and sensitivity case

Within each transmission framework, the sensitivity cases are sorted by 2050 VRE capacity share. Peak coincident end-use demand is shown as vertical dotted lines.

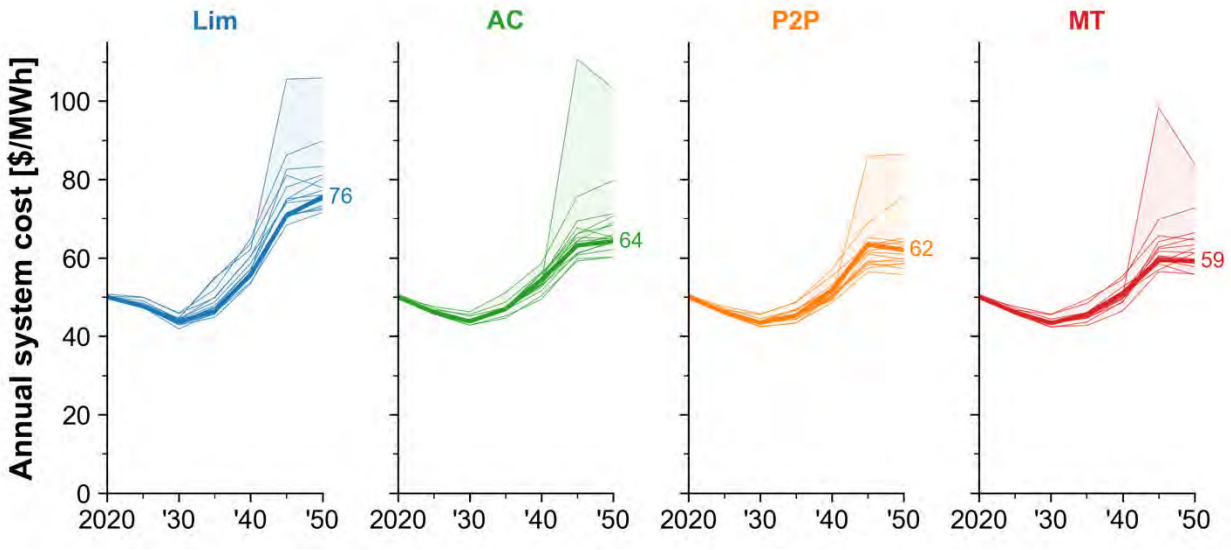


Figure D-13. Annual system cost ($/MWh) for the four transmission frameworks and all sensitivity cases under Mid-Demand 90% by 2035 conditions

Annual system cost is given by the sum of undiscounted annualized electricity system expenditures (fixed and operating) and tax credits, divided by annual end-use electricity demand (excluding induced demand from storage charging, H_2 production for use in H_2-CTs, and transmission losses).

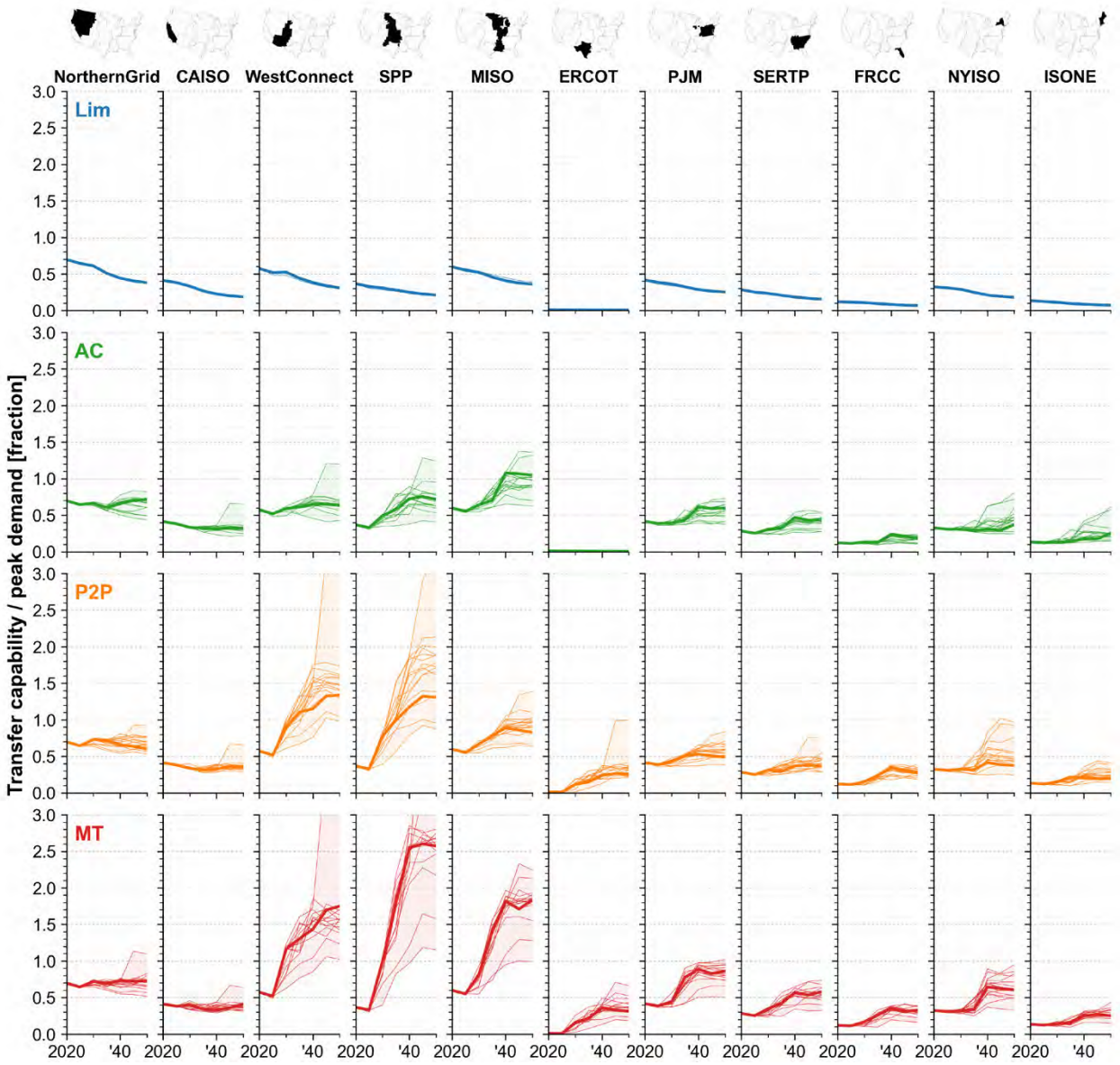


Figure D-14. Ratio of interregional transfer capability to peak demand for the 11 planning regions with Mid-Demand 90% by 2035 assumptions across the four transmission frameworks and all sensitivity cases

Interregional transfer capability for a given planning region is defined as the sum of import/export capacity between that planning region and other planning regions.

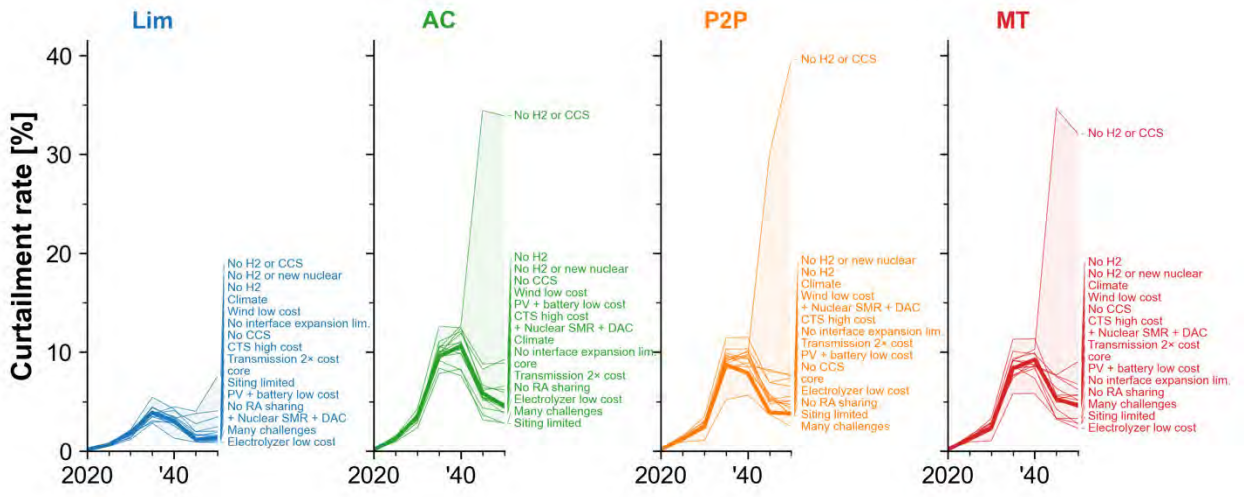


Figure D-15. National average VRE curtailment rate [$MWh_{curtailed}$ / $MWh_{available}$] with Mid-Demand 90% by 2035 assumptions for all sensitivity cases

D.3 Additional Resource Adequacy Results

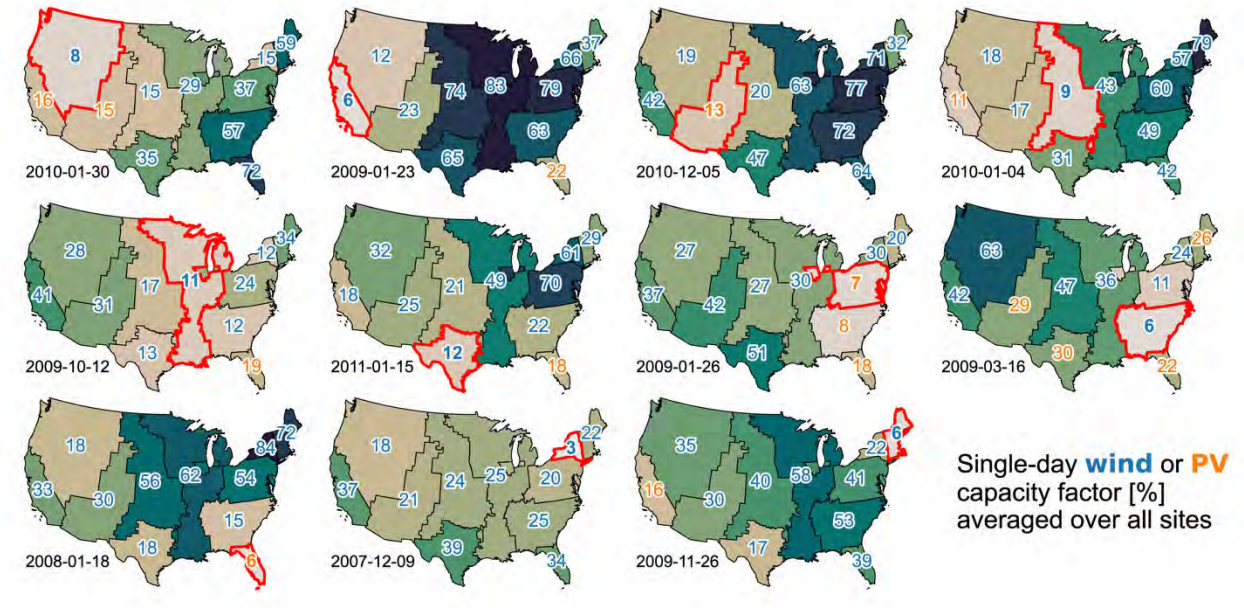


Figure D-16. Single-day wind (blue) or PV (orange) capacity factor on the least-windy/sunny day from 2007 to 2013 weather years in each planning region

For each map, the focused planning region is outlined in red, the date of the least-windy/sunny day in that region is given in the lower left, and the values and shading in each region represent the daily wind or PV capacity factor on that date, whichever is larger. (For example, on 2010-01-30, the wind capacity factor in NorthernGrid is 8% and the solar capacity factor is ≤8%; on the same day, the solar capacity factor in CAISO is 16%.) Planning region values are taken as the available-capacity-weighted average modeled capacity factor over all resource sites in the planning region. Capacity factors are modeled using the reV model as discussed in Appendix A.2. Most of these sites are never developed; if only developed or higher-quality resource sites in each planning region were included, the capacity factors would be higher than shown here.

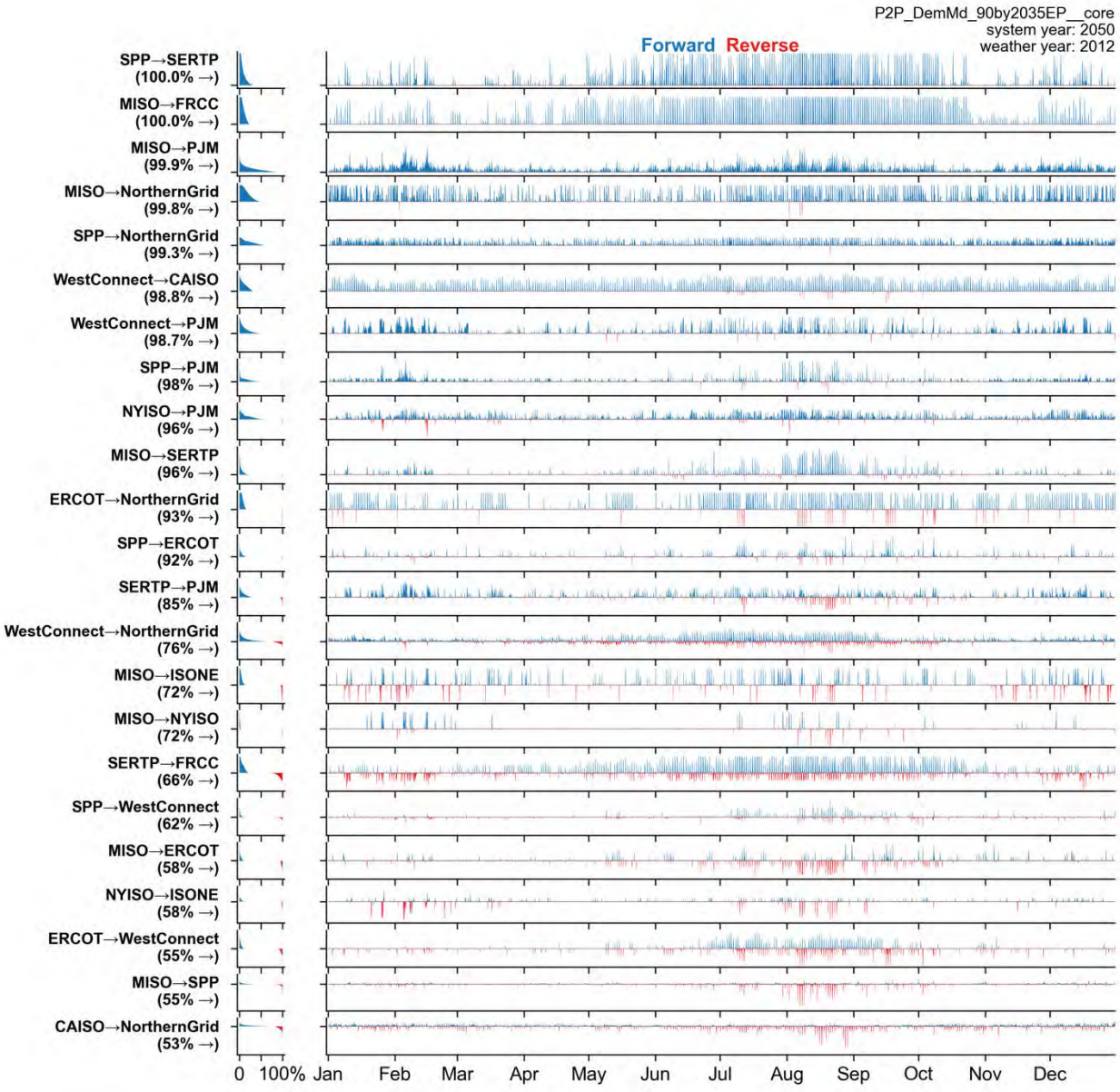


Figure D-17. Hourly interregional transmission flows for the P2P transmission framework in 2050 under Mid-Demand 90% by 2035 conditions as modeled by PRAS

Interfaces are labeled according to the predominant direction of flow. Flow in the predominant ("forward") direction is shown as positive blue values; flow in the "reverse" direction is shown as negative red values. Interfaces are sorted and labeled by the fraction of total flow in the "forward" direction on a MWh basis over the 7 weather years spanning 2007–2013. Distributions on the left include all weather years; hourly profiles on the right include only 2012 for clarity.

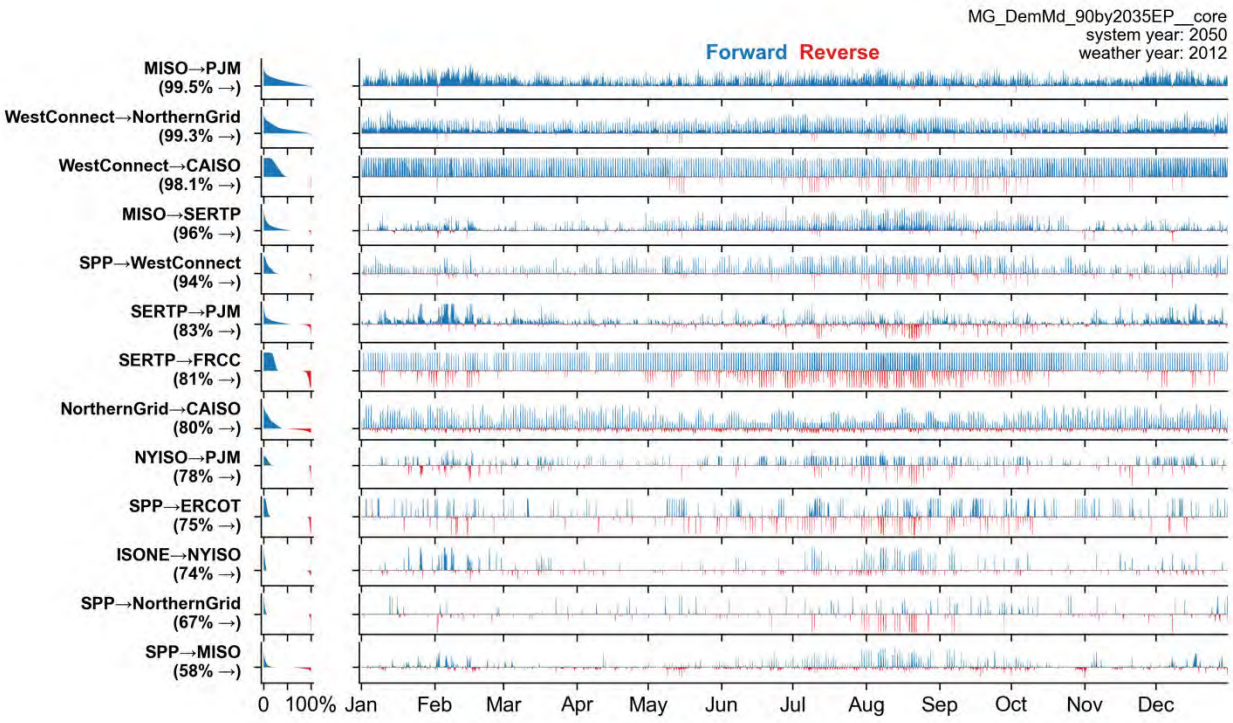


Figure D-18. Hourly interregional transmission flows for the MT transmission framework in 2050 under Mid-Demand 90% by 2035 conditions as modeled by PRAS

Data are presented in the same manner as Figure D-9.

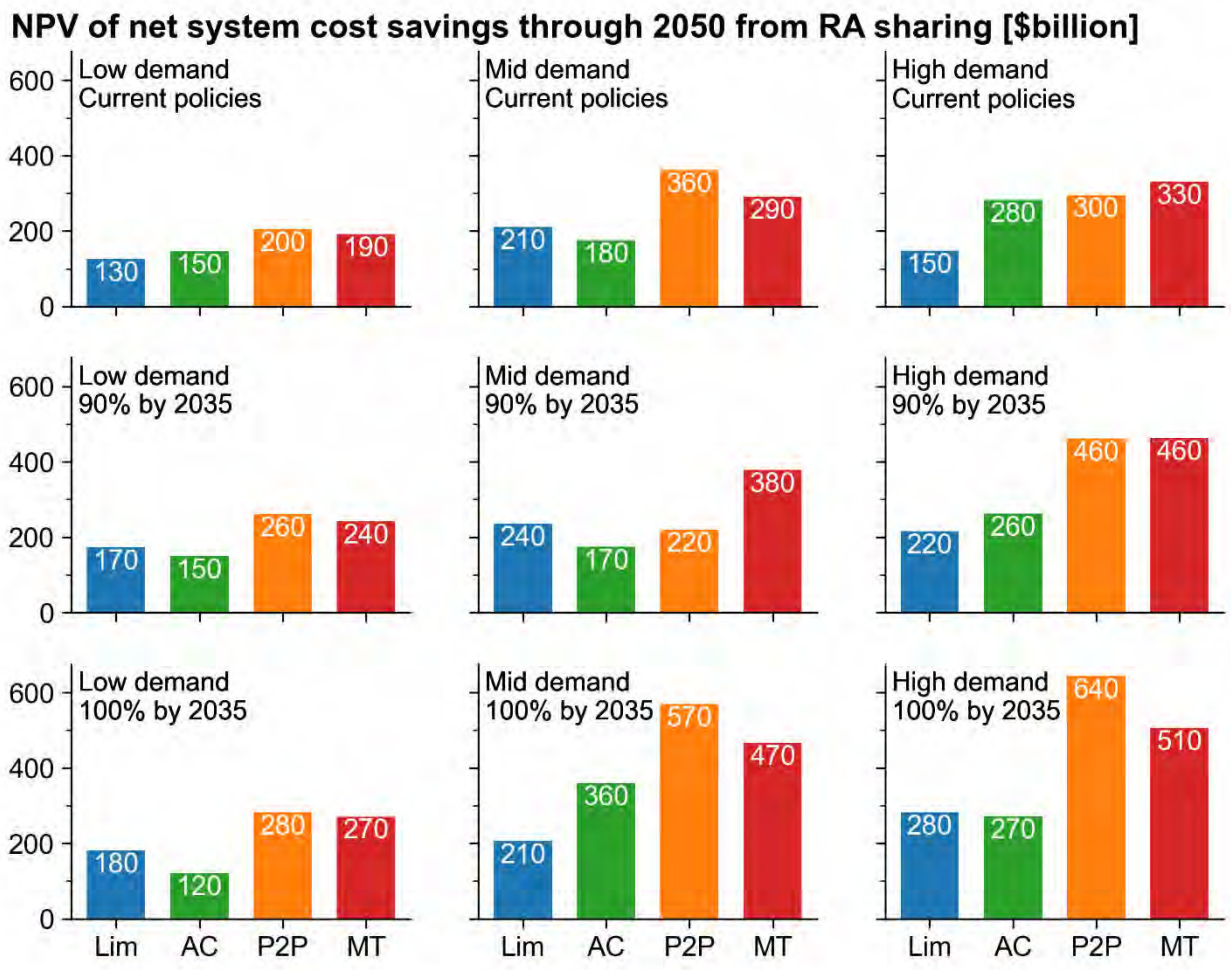


Figure D-19. Impact of the allowance of interregional RA sharing on system cost for each of the demand and emissions assumptions

Data are presented in the same manner as Figure 40a. The "No RA Sharing" sensitivity case was run for each set of demand and emissions assumptions to generate this figure.

D.4 Regional Economic Benefits

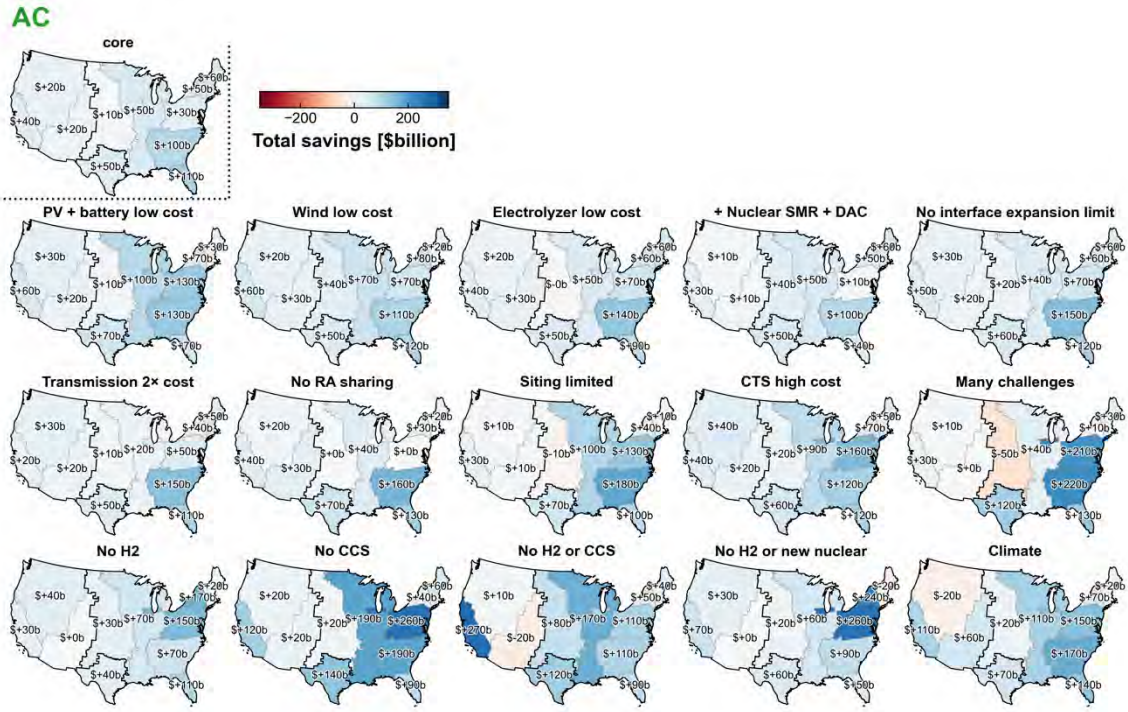


Figure D-20. Net present value of system savings in the AC transmission framework by region in $billion of avoided costs relative to the Limited framework under Mid-Demand 90% by 2035 scenario assumptions

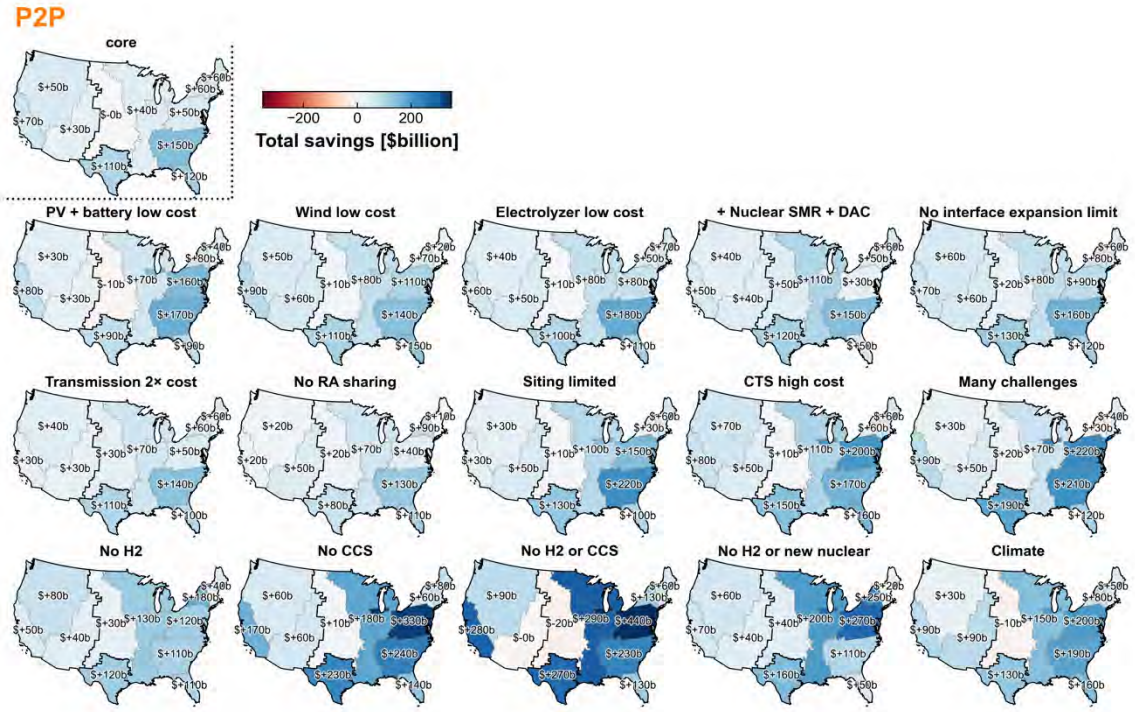


Figure D-21. Net present value of system savings in the P2P transmission framework by region in $billion of avoided costs relative to the Limited framework under Mid-Demand 90% by 2035 scenario assumptions

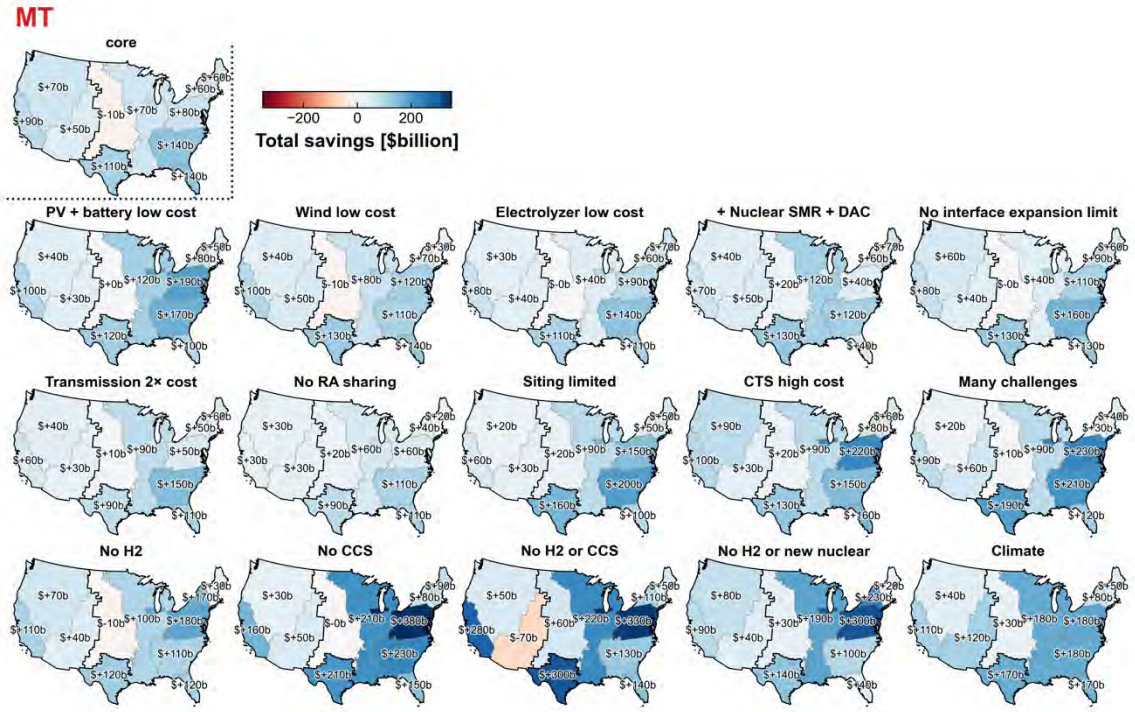


Figure D-22. Net present value of system savings in the MT transmission framework by region in $billion of avoided costs relative to the Limited framework under Mid-Demand 90% by 2035 scenario assumptions

Table D-1. Wind and Solar Capacity (GW) by State in the Core Mid-Demand 90% by 2035 Scenarios

	Land-based wind								Utility-scale solar							
	2035				2050				2035				2050			
	Lim	AC	P2P	MT	Lim	AC	P2P	MT	Lim	AC	P2P	MT	Lim	AC	P2P	MT
AL	3.7	8.6	7.3	12.4	8.1	12.6	24.3	16.8	3.2	23.2	17.1	16.5	18.3	50.5	31.1	43.6
AR	10.4	12.2	20.7	14.4	15.3	12.8	26.4	21.8	1.8	1.8	1.8	3.1	1.6	4.6	18	4.8
AZ	3.3	6.2	2.8	4.1	3.5	10.4	20.3	3.8	19.1	42.7	19	22.4	27.8	62.5	19.2	41
CA	7.5	8.1	7.8	8.9	8.9	12	12.2	10.3	28	32.5	33.5	33.6	25.7	40.5	46.1	47.9
CO	12.3	15.9	9.3	7.8	13.1	26.9	15	13.6	3.5	7.7	8.5	9.2	12	12.5	11.1	12.4
CT	0.6	0.7	0.7	0.7	0.6	1.3	1.1	1	0.5	0.5	0.5	0.5	0.3	0.3	0.3	0.3
DE	1.3	1.9	2.7	1.9	2.1	1.9	2.7	1.9	2.2	0.3	0.3	0.3	4.3	4.3	2.7	2.2
FL	3.2	17.7	12.2	6.7	3.6	27.4	15.6	17.7	18.2	56.8	54.1	44.5	35.8	103.7	82.8	74.8
GA	0	4.2	13.7	3.1	2.3	4.2	14.3	16.6	4.7	4.7	4.7	4.7	2.7	13.8	2.7	2.7
IA	15.9	13.4	16.1	13.4	19.2	7.7	15.3	40.6	2.3	6.9	0.3	0.3	2.3	6.9	1.9	7.6
ID	7.2	8.2	7.7	9.8	10.7	15.4	12.5	15.4	0.4	8.6	10.2	3.8	1.1	15.9	11.4	12.5
IL	18.5	22.2	17.7	16.8	24.9	19.5	31.9	39.7	9.3	11	5.8	5.3	11.9	10.9	7.8	10.2
IN	17.1	34.7	24.8	24.4	27.9	33.5	36.9	33	5.5	33.2	33	26.9	7.2	41.2	43.1	34.4
KS	10.6	14.9	18	13.1	11.5	14.9	19.4	19.7	2.8	22.1	26.4	19.4	5.3	26.4	30.6	31
KY	10.9	23.7	12.9	14.7	17.6	24.2	20.7	20.2	13.6	22.4	27	25.5	44.1	44.6	58.4	52
LA	9.3	17.9	18.3	17.9	14	23.9	29.1	25.6	7.5	7.7	4.9	4.4	13.1	18.1	8.4	10.2
MA	0.1	0.1	0.2	0.2	1.7	1	1.5	0.6	1.4	1.4	1.4	1.4	0.7	0.7	0.7	0.7
MD	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	3.9	3.1	3.1	3.1	5.8	5.4	5.5	5.4
ME	2.9	3.1	3.1	3.1	2.7	4.5	4.7	5.4	0.8	0.8	0.8	0.8	0.7	1.7	0.7	0.7
MI	22.3	38.8	52.3	38.8	26.1	73.9	53	46	5.6	10.2	2	4.7	9.7	34.3	8.9	9.8
MN	13.9	18.1	34.1	46.1	20.9	22.7	47.1	48.2	5.1	5.2	1.2	1.2	4.9	5.7	0.2	10.4
MO	15.9	19.8	23.6	16.2	29.8	30.6	27.3	61.2	15.4	10.6	6.2	8.5	21.8	11.2	17	9.7
MS	19.7	22.7	30.3	22.6	23.7	33.8	38.5	41.9	23.9	20.1	23.1	14	41.9	27	25.4	18.8
MT	7.9	7.2	5.5	9.4	10.2	10.9	6.4	9.5	0.9	1.2	1.9	0.8	1.3	1.2	3.3	2.8
NC	3.3	34.4	29.1	28.9	13.4	46.9	43.6	31.9	7.3	41.7	41.2	35.9	7.3	61.9	79.2	51.5
ND	11.9	13.5	24.7	36.3	13.6	37	28.3	46.2	0	6.4	0	0	0.7	11.4	12.6	13.3
NE	13.1	24.9	36.2	40.2	15.7	23.6	44.2	63.9	3	8.5	0.1	0.1	4.7	8.5	5	7.7
NH	0.2	0.5	0.5	0.5	2.2	4.3	2.3	4.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
NJ	0	0.7	1.8	0.7	0	0.7	1.8	0.7	1	1	1	1	0.6	0.6	0.6	0.6
NM	12.9	17.9	12.4	15.8	16.4	24.1	52.4	15	5.4	5.3	10.1	8.7	8.6	9.1	15.9	10.7
NV	0.2	0.4	0.4	0.4	0.3	4.2	2.7	2.5	8	21.5	17.2	17.6	27.9	25	20.9	20.6
NY	8.7	8.4	8.4	8.3	8.5	18.6	21.8	19.2	4.4	4.2	4.2	4.2	4.8	7.4	28.4	34.4
OH	9.7	20.4	19.3	10.9	30.2	20.3	30.2	10.5	4.4	4.6	4.4	4.4	8.4	4.5	4.4	4.4
OK	18.9	32.5	30.2	49.8	22.7	59.4	62.3	56.1	9.2	6.2	6.9	10.3	16.3	6.1	14.7	12.1
OR	9.1	9.7	10.8	5.4	8.5	12.2	11.9	16.3	1.6	1.6	1.6	1.6	2.8	8.4	5	1
PA	4.2	6.4	8.9	7.2	6.9	8.7	18.9	9	1.1	0.8	0.8	0.7	3.5	3.1	4.2	2.3
RI	0.9	0.8	0.8	0.8	1.2	1.2	1.2	1.2	0.3	0.3	0.3	0.3	3.3	3.4	1.4	2.4
SC	2.7	17.3	14.7	8.3	6.8	19.9	19.9	19.9	4.3	10.1	8.9	8.2	15.3	17.9	18	29.3
SD	3.3	9	9.7	14.4	5.2	8.3	13.7	16.8	0.3	0.1	0.1	0.1	1.3	0.1	0.9	0.8
TN	7.1	9.3	6.8	9.3	9.7	11.1	13.3	9.3	1.2	2.6	8.2	1.9	1.1	2.5	20.1	1.8
TX	88.9	109.6	128	136.6	110.2	147.9	164.3	175	66.8	116.1	96.1	109	120.7	159.4	163.5	190.2
UT	0.7	1	0.9	0.9	0.9	2.4	2	0.8	2.9	2.8	2.8	2.8	6.8	9.5	6.5	1.8
VA	5.7	18.9	24	16.4	14.6	21.6	29.6	30.8	16.5	21.7	20.8	10.8	35.6	36.3	45	17.8
VT	0.5	1	1.2	0.7	3.4	4.9	2.5	2.7	0.2	0.2	0.2	0.2	0.1	4.3	0.1	0.1
WA	10.4	15.4	12.3	15.1	13.6	26.7	29.7	19.4	0.4	0.4	0.4	0.4	13.1	0.6	7.2	6.2
WI	17.5	13.6	18.6	13.8	23.5	39.2	19.1	17	4.5	9.4	2.3	2.3	18.1	14.3	15	11
WV	0.9	0.9	0.9	0.9	3.4	0.7	0.7	0.4	0	0	0	0	0	0	0	0
WY	19	26.3	35	41.9	20.6	43	42.9	48.8	2.3	0.1	1.1	0.6	6.7	0	2.2	5.6

Appendix E. Transmission Value Analysis

The economic analysis presented here identifies and evaluates quantifiable benefits associated with transmission development across NTP Study zonal planning and operational analysis. The following sections outline the overall approach to quantify and regionally disaggregate the benefits of transmission applied to the NTP zonal scenarios.

E.1 Multivalue

This analysis considers a broad range of transmission benefits including reduced capital and operating costs, reduced cost of meeting reliability requirements, and increased capture of federal and state incentives. Using outputs from the zonal production cost model, the economic analysis includes six categories of transmission benefits (Figure 42). Annualized savings for capital investments are based on the equivalent annual cost assuming a 1.7% discount rate. Transmission assets are assumed to have a 40-year asset life; all other technologies are assumed to have a 20-year asset life.

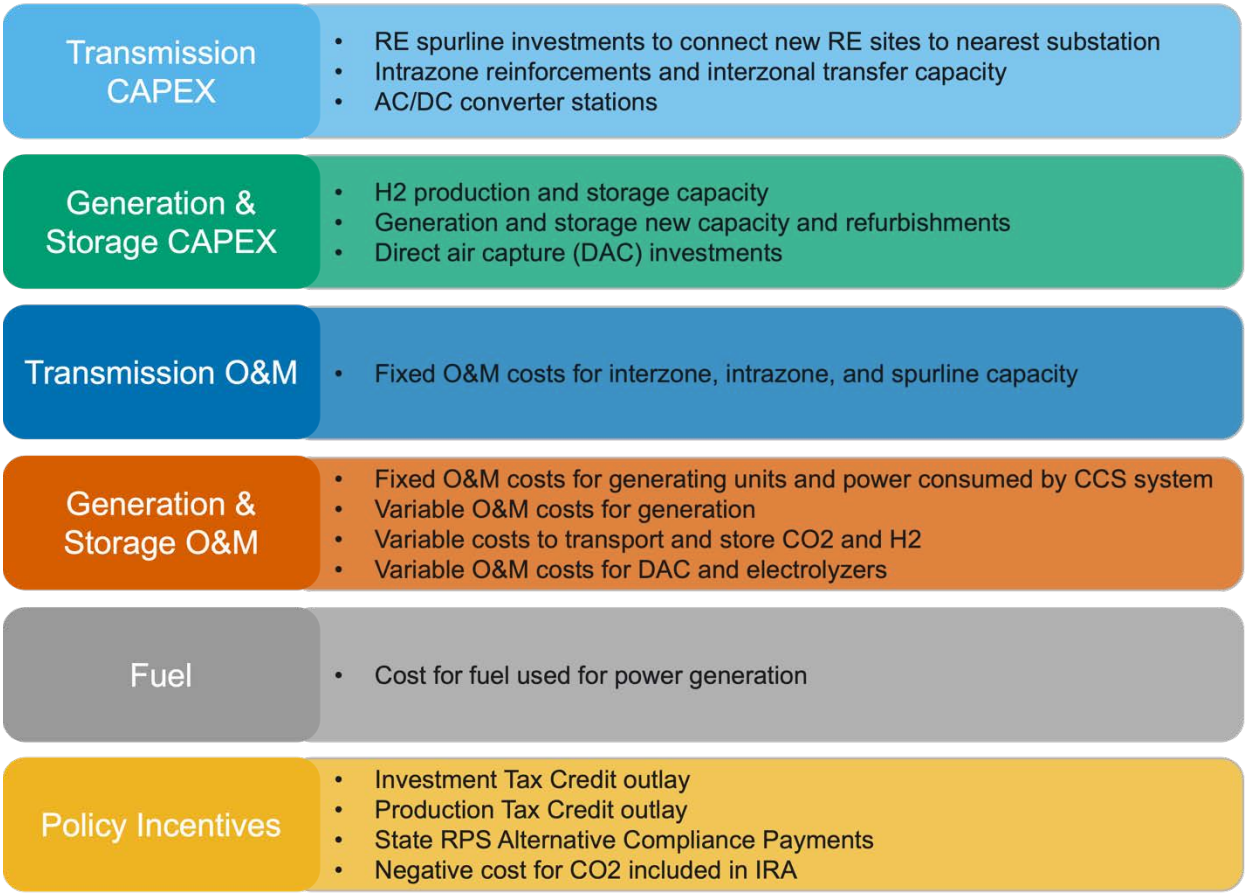


Figure E-1. System costs included in transmission valuation. Many benefits are correlated and not mutually exclusive.

E.2 System Perspective

The NTP Study evaluates transmission investments and operations across the entire contiguous United States. The economic analysis evaluates the value of transmission across this entire system as well as to a given region (e.g., ISONE, NYISO, CAISO). The analysis does not disaggregate the benefits experienced by different types of network users within each region (e.g., generators, consumers). In addition, no assumptions about how transmission cost recovery is allocated within a region or among customer classes are made.

E.3 Project Scope

This analysis evaluates the net benefits for the portfolio of transmission investments identified in NTP Study accelerated transmission frameworks rather than evaluating individual projects or transmission corridors. This approach reflects planning processes in place, such as MISO's multivalue project process that evaluates bundles of projects. It also aligns with the NTP Study approach, in which transmission investments and system operations are optimized on a multiregion scale. To isolate the impact of specific types of transmission development, the reference scenario (Limited) is compared with alternative "change" cases (AC, P2P, MT) that represent different types of transmission development.

E.4 Planning Horizon

The analysis considers an almost 30-year planning horizon, covering the period 2022–2050.[53] This extended planning horizon will inform how the benefits of transmission change over time as the underlying power system changes. It is also aligned with guidance under consideration by FERC to consider system needs and changes 20+ years in the future for transmission planning.

E.5 Uncertainty

The transmission valuation captures a range of possible future outcomes, drawing from the broad set of NTP Study sensitivity cases including macroeconomic drivers such as technology prices and availability as well as a range of system states such as different weather conditions. This analysis uses scenario-based comparisons to capture uncertainty system costs across a range of system futures.

E.6 Regional Disaggregation: Adjusted Production Cost

As interregional transmission enables more coordinated operation of low-cost generation resources, the distribution of operating costs within each region changes. For systemwide analysis, operating costs comprise variable operation and maintenance, fuel, and startup and shutdown. These metrics are sufficient to evaluate the change in operating costs for the entire system but, when evaluating the benefit distribution among regions, a further consideration is needed to capture the

[53] 2030 is the first year in which new interregional transmission can be commissioned in the NTP Study modeling.

transmission benefits of interregional trade to each region. The adjusted production cost (APC) metric is used to evaluate these benefits. The APC is the difference in total production costs adjusted for import costs and export revenues with and without a proposed transmission upgrade. This metric is used among independent system operators/regional transmission operators in the United States for transmission valuation and cost allocation including SPP, MISO, and PJM and is defined as follows:

$$\text{APC} = \text{Production Cost} + \text{Purchase Costs} - \text{Generator Revenue}$$

where

$$\text{Purchase Costs} = (\text{Hourly Consumer Load} + \text{Storage Charging} + \text{Imports}) \times \text{Locational Marginal Price}$$

$$\text{Generator Revenue} = \text{Hourly Generation} \times \text{Locational Marginal Price}$$

A key benefit of the APC when trying to disaggregate transmission benefits is that it does not strictly rely on the physical location where costs are incurred to estimate costs and benefits. As a simple example, a new transmission upgrade may enable the development of low-cost generation capacity in one region (Region A) that can serve additional load in a neighboring region (Region B). Strictly looking at where costs are occurring, the new transmission line will increase capital and operating costs in Region A because it is building more capacity and generating more. By contrast, capital and operating costs will decrease in Region B because it is building less capacity and relying on imports to meet its load. However, Region A is also benefiting through increased sales of power to its neighbors. In addition, Region B is not getting these imports for free; it incurs some cost to purchase imported energy. By including an adjustment for import costs and export revenues, the APC can capture these benefits. Figure E-1 shows the production cost adjustment (change in purchase cost – generator revenue) added to the transmission value for each region and topology for the core Mid-Demand 90% by 2035 scenarios.[54]

[54] For this study, the adjusted production cost is based on zonal marginal prices from the capacity expansion model based on the marginal price of meeting capacity, energy, and policy requirements in each balancing area. The capacity expansion model represents each modeled year with 33 representative days at 4-hr resolution, for a total of 198 modeled hours. Further study with full 8,760 hourly resolution at a nodal resolution can be used to refine the estimated adjusted production cost for each region.

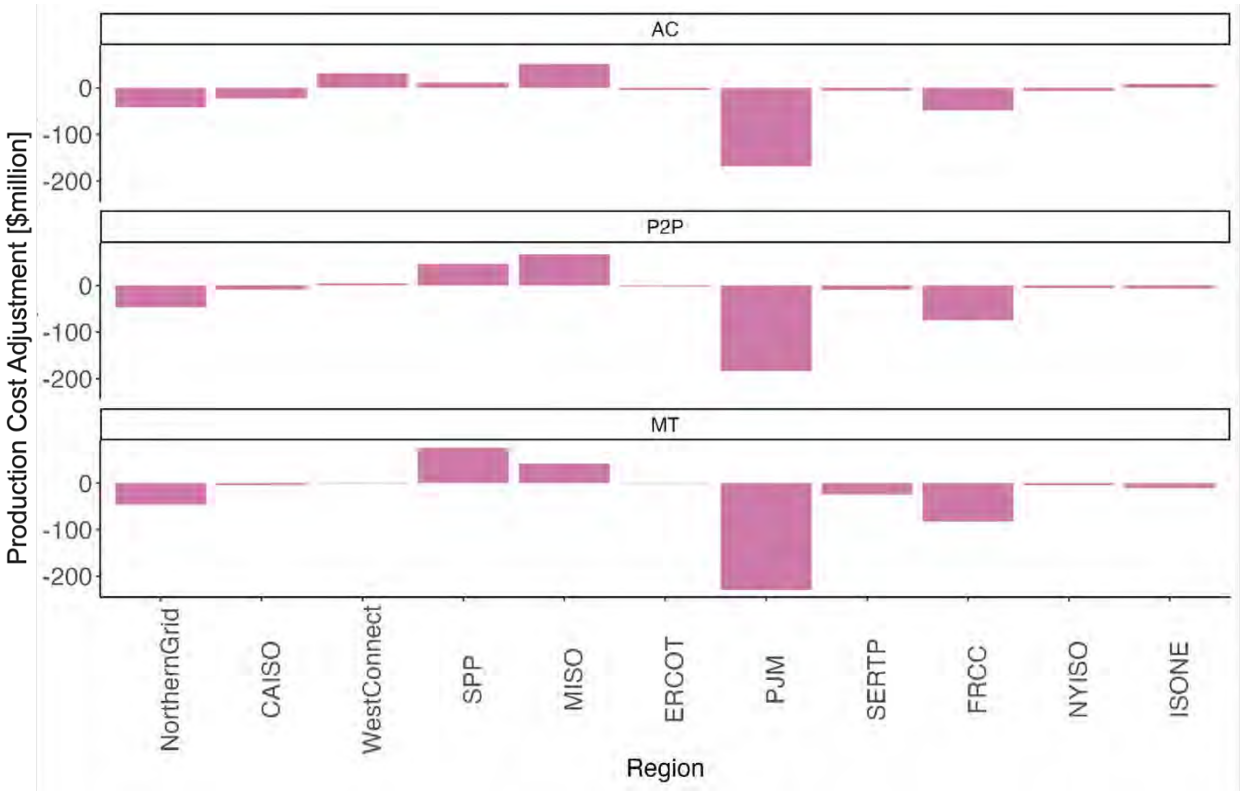


Figure E-2. Production cost adjustment for each transmission planning region and network topology for the core Mid-Demand 90% by 2035 scenarios ($million)

Appendix F. High Opportunity Transmission Interfaces: Regional Detail

The High Opportunity Transmission (HOT) analysis highlights robustly chosen transmission expansion opportunities for each of the 11 planning regions and each of the AC, P2P, MT transmission frameworks. The following maps show the interfaces with nearby planning regions and the 25th percentile of new transmission capacity built across those interfaces in the 16 sensitivity cases. These are the same data as shown in the national maps in the Text Box in Section 3.3 but provide a more granular view of transmission expansion in that planning region. The tables accompanying the maps show the 25th percentile as well as the 50th and 75th percentile results to inform more ambitious transmission development opportunities. Also included in the tables is the amount of existing transmission capacity across that interface. The interfaces are color coordinated to identify them in the table and map and across the other transmission framework maps. Three maps and associated tables are shown for each region showing the AC, P2P, and MT frameworks in that order. Some regions are grouped together when they have common borders (e.g., SERTP and FRCC; NYISO and ISONE).



CAISO

AC Framework

Interface Capacity (GW)

REGION	EXISTING	Percentile of New Capacity 25TH	50TH	75TH
Northern Grid S.	11	0.1	0.7	1.4
West Connect S.	5.3	3.6	4.0	4.7



P2P Framework

Interface Capacity (GW)

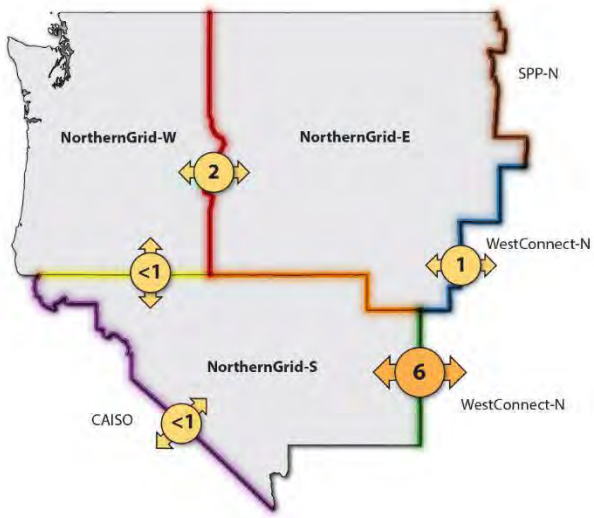
REGION	EXISTING	Percentile of New Capacity 25TH	50TH	75TH
Northern Grid S.	11	0	0.1	0.4
West Connect S.	5.3	3.0	4.1	4.9



MT Framework

Interface Capacity (GW)

REGION	EXISTING	Percentile of New Capacity 25TH	50TH	75TH
Northern Grid S.	11	0	0.4	0.6
West Connect S.	5.3	6.2	6.8	9.1

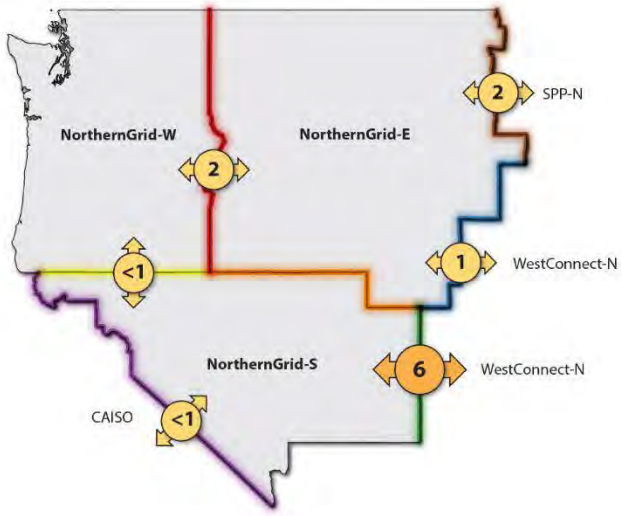


NorthernGrid

AC Framework

Interface Capacity (GW)

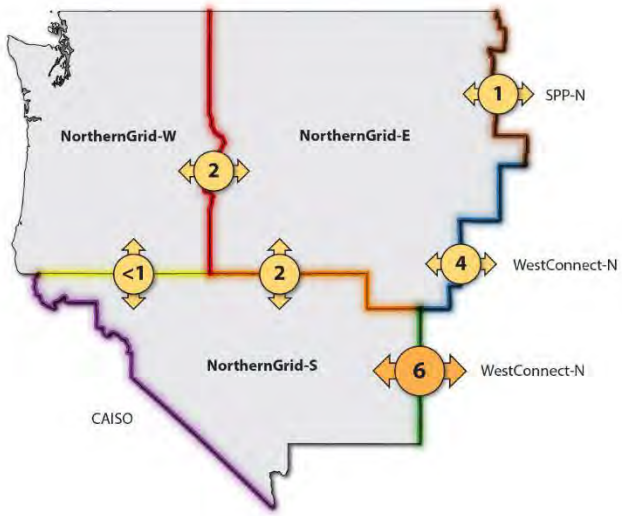
REGION	EXISTING	Percentile of New Capacity 25TH	50TH	75TH
NG-W, NG-E	13.2	1.7	1.7	1.7
NG-E, SPP-N	0.2	0	0	0
NG-E, WC-N	4.0	1.1	1.2	1.8
NG-E, NG-S	3.1	0	0	0.6
NG-W, NG-S	0.5	0.1	0.4	1.2
NG-S, WC-N	2.4	6.3	7.1	7.2
NG-S, CAISO	11	0.1	0.7	1.4



P2P Framework

Interface Capacity (GW)

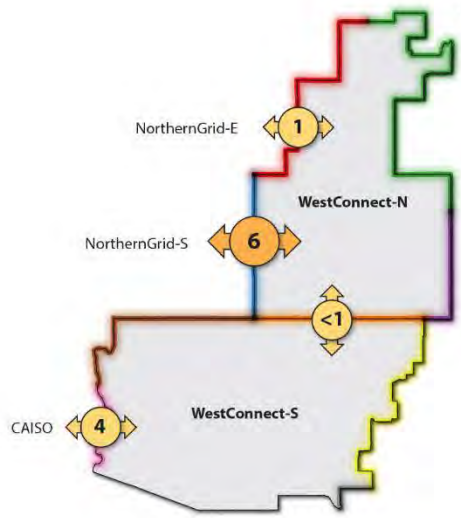
REGION	EXISTING	Percentile of New Capacity 25TH	50TH	75TH
NG-W, NG-E	13.2	1.7	1.7	1.7
NG-E, SPP-N	0.2	1.8	2.2	2.5
NG-E, WC-N	4.0	1.4	2.1	2.5
NG-E, NG-S	3.1	0	0	0
NG-W, NG-S	0.5	0.1	0.3	0.5
NG-S, WC-N	2.4	5.8	7.0	7.9
NG-S, CAISO	11	0.1	0.4	0.3



MT Framework

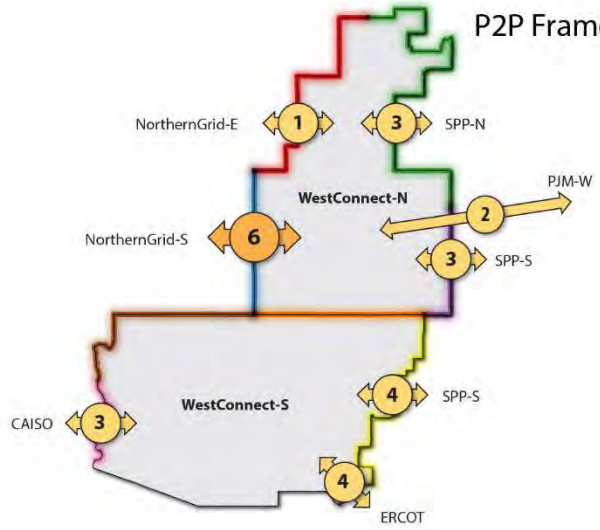
Interface Capacity (GW)

REGION	EXISTING	Percentile of New Capacity 25TH	50TH	75TH
NG-W, NG-E	13.2	1.7	1.7	1.7
NG-E, SPP-N	0.2	1.2	1.8	2.1
NG-E, WC-N	4.0	3.9	5.0	5.7
NG-E, NG-S	3.1	2.0	2.6	3.9
NG-W, NG-S	0.5	0.2	0.5	1.2
NG-S, WC-N	2.4	6.0	6.4	6.7
NG-S, CAISO	11	0	0.4	0.6



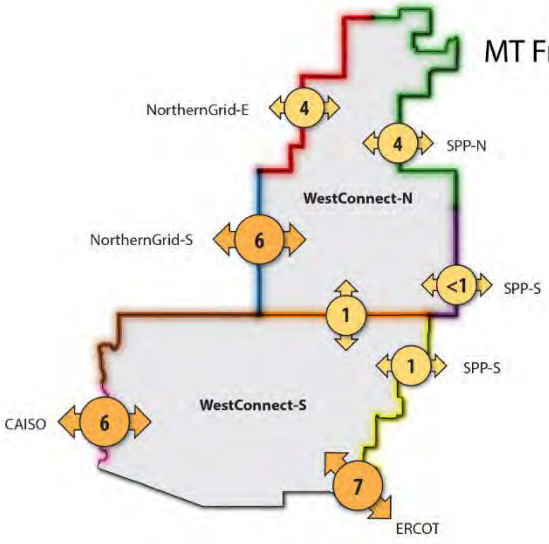
Interface Capacity (GW)

REGION	EXISTING	Percentile of New Capacity 25TH	50TH	75TH
WC-N, NG-E	4.0	1.1	1.2	1.8
WC-N, NG-S	2.4	6.3	7.1	7.2
WC-N, SPP-N	0.5	0	0	0
WC-N, SPP-S	0.2	0	0	0
WC-N, WC-S	1.4	0.1	0.7	0.8
WC-S, NG-S	7.3	0	0	0
WC-S, SPP-S	0.4	0	0	0
WC-S, ERCOT	0	0	0	0
WC-S, CAISO	5.3	3.6	4.0	4.7



Interface Capacity (GW)

REGION	EXISTING	Percentile of New Capacity 25TH	50TH	75TH
WC-N, NG-E	4.0	1.4	2.1	2.5
WC-N, NG-S	2.4	5.8	7.0	7.9
WC-N, SPP-N	0.5	2.6	3.1	3.9
WC-N, SPP-S	0.2	2.7	3.1	3.9
WC-N, WC-S	1.4	0	0.1	0.3
WC-S, NG-S	7.3	0	0	0
WC-S, SPP-S	0.4	4.2	5.7	6.5
WC-S, ERCOT	0	4.1	5.7	7.3
WC-S, CAISO	5.3	3.0	4.1	4.9

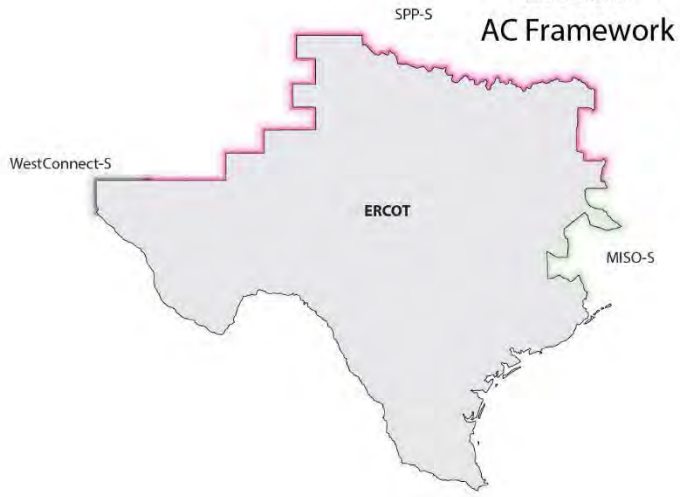


Interface Capacity (GW)

REGION	EXISTING	Percentile of New Capacity 25TH	50TH	75TH
WC-N, NG-E	4.0	3.9	5.0	5.7
WC-N, NG-S	2.4	6.0	6.4	6.7
WC-N, SPP-N	0.5	3.9	5.4	6.6
WC-N, SPP-S	0.2	0.5	0.9	1.5
WC-N, WC-S	1.4	1.0	1.6	2.4
WC-S, NG-S	7.3	0	0	0
WC-S, SPP-S	0.4	1.4	1.9	3.7
WC-S, ERCOT	0	6.5	7.1	9.5
WC-S, CAISO	5.3	6.2	6.8	9.1

ERCOT

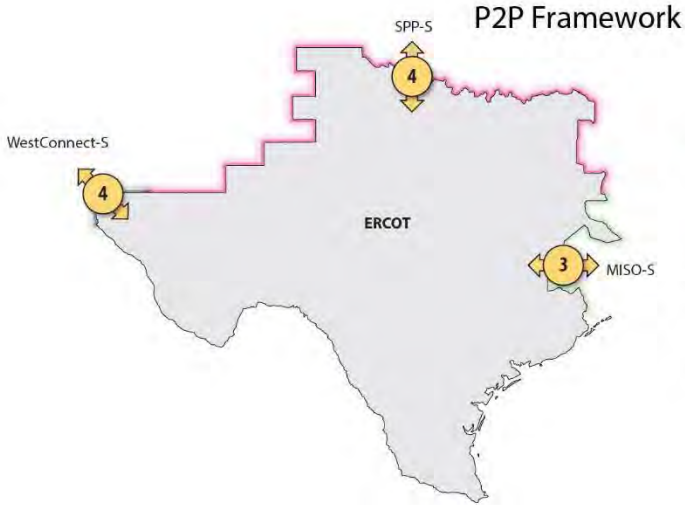
AC Framework



Interface Capacity (GW)

REGION	EXISTING	Percentile of New Capacity 25TH	50TH	75TH
ERCOT, SPP-S	0.8	**0**	0	0
ERCOT, WC-S	0	**0**	0	0
ERCOT, MISO-S	0	**0**	0	0

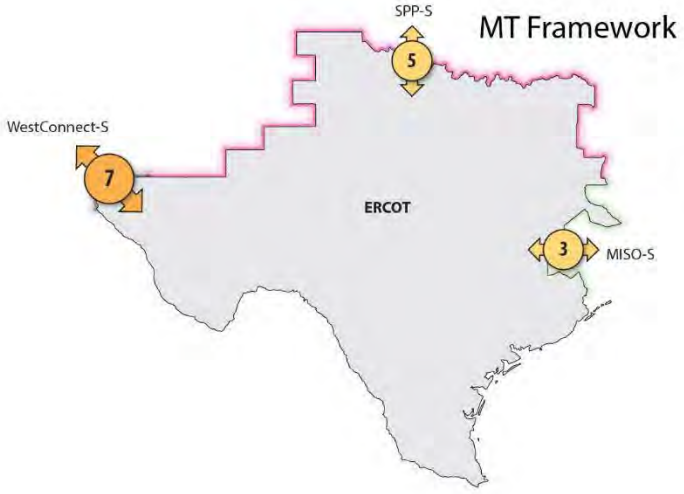
P2P Framework



Interface Capacity (GW)

REGION	EXISTING	Percentile of New Capacity 25TH	50TH	75TH
ERCOT, SPP-S	0.8	**4.1**	5.1	5.7
ERCOT, WC-S	0	**4.1**	5.7	7.3
ERCOT, MISO-S	0	**3.3**	4.4	4.9
Nonadjacent Region Interfaces				
ERCOT, MISO-N	0	**0**	0.2	1.3
ERCOT, NG-S	0	**0**	0	0.4
ERCOT, SPP-N	0	**0**	0	0.2
ERCOT, WC-N	0	**0**	0	0.3

MT Framework

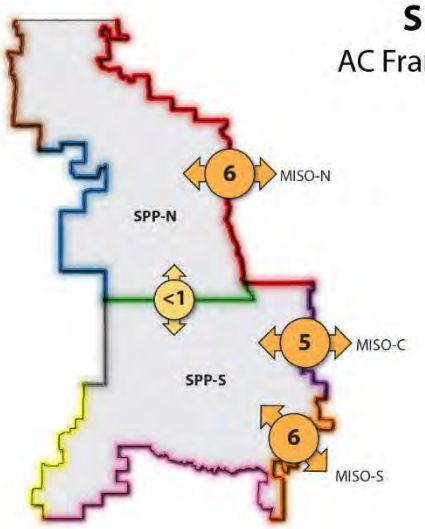


Interface Capacity (GW)

REGION	EXISTING	Percentile of New Capacity 25TH	50TH	75TH
ERCOT, SPP-S	0.8	**4.9**	6.3	12
ERCOT, WC-S	0	**6.5**	7.1	9.5
ERCOT, MISO-S	0	**2.6**	3.7	4.6

SPP

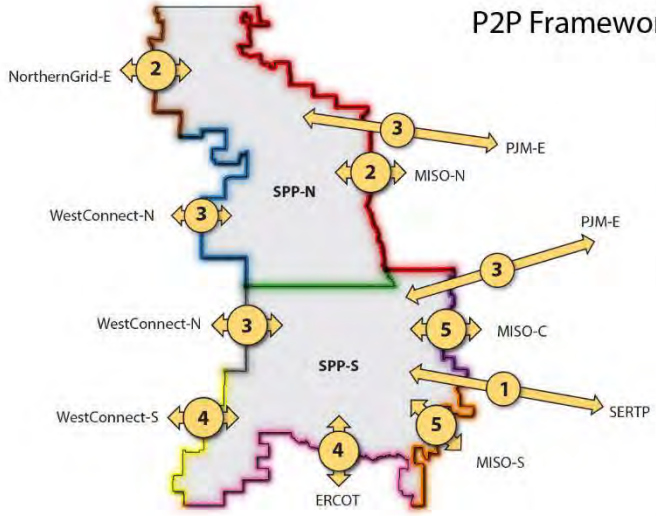
AC Framework



Interface Capacity (GW)

REGION	EXISTING	Percentile of New Capacity 25TH	50TH	75TH
SPP-N, NG-E	0.2	0	0	0
SPP-N, MISO-N	10.0	6.0	7.6	9.4
SPP-N, WC-N	0.5	0	0	0
SPP-N, SPP-S	5.4	0.2	0.3	0.4
SPP-S, MISO-C	2.0	4.7	6.0	6.0
SPP-S, MISO-S	3.3	5.8	6.4	7.0
SPP-S, WC-N	0.2	0	0	0
SPP-S, WC-S	0.4	0	0	0
SPP-S, ERCOT	0.8	0	0	0

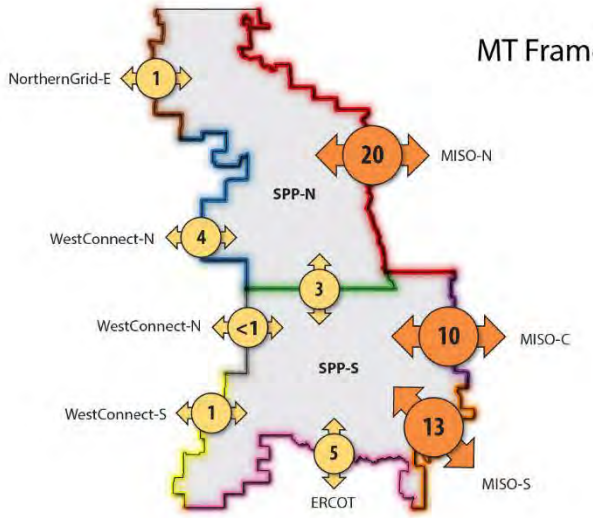
P2P Framework



Interface Capacity (GW)

REGION	EXISTING	Percentile of New Capacity 25TH	50TH	75TH
SPP-N, NG-E	0.2	1.8	2.2	2.5
SPP-N, MISO-N	10.0	1.7	2.6	3.8
SPP-N, WC-N	0.5	2.6	3.1	3.9
SPP-N, SPP-S	5.4	0	0.2	0.7
SPP-S, MISO-C	2.0	4.8	5.6	5.8
SPP-S, MISO-S	3.3	4.5	5.5	6.3
SPP-S, WC-N	0.2	2.7	3.1	3.9
SPP-S, WC-S	0.4	4.2	5.7	6.5
SPP-S, ERCOT	0.8	4.1	5.1	5.7
Nonadjacent Region Interfaces				
SPP-N, PJM-E	0	3.4	5.2	10
SPP-S, PJM-E	0	3.3	4.7	7.1
SPP-S, SRTP	0	1.0	2.5	4.6

MT Framework

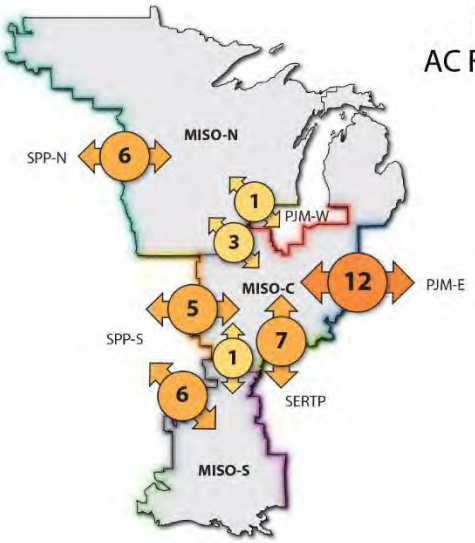


Interface Capacity (GW)

REGION	EXISTING	Percentile of New Capacity 25TH	50TH	75TH
SPP-N, NG-E	0.2	1.2	1.8	2.1
SPP-N, MISO-N	10.0	20.3	24.8	27.8
SPP-N, WC-N	0.5	3.9	5.4	6.6
SPP-N, SPP-S	5.4	3.4	5.8	7.5
SPP-S, MISO-C	2.0	9.9	13.8	16.8
SPP-S, MISO-S	3.3	12.6	16.5	18.1
SPP-S, WC-N	0.2	0.5	0.9	1.5
SPP-S, WC-S	0.4	1.4	1.9	3.7
SPP-S, ERCOT	0.8	4.9	6.3	12.0

MISO

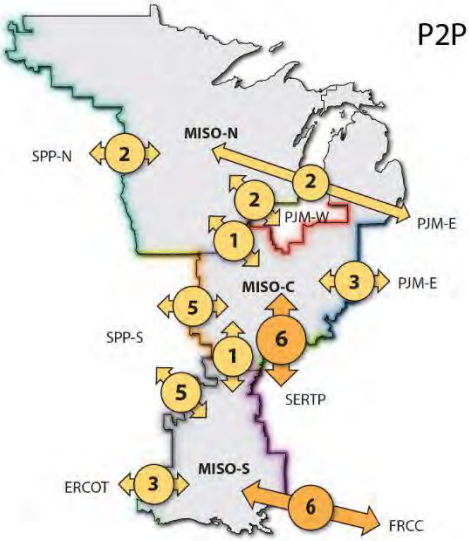
AC Framework



Interface Capacity (GW)

REGION	EXISTING	Percentile of New Capacity 25TH	50TH	75TH
MISO-N, SPP-N	10.0	6.0	7.6	9.4
MISO-N, PJM-W	5.0	1.4	2.9	4.9
MISO-N, MISO-C	5.5	2.6	4.3	5.1
MISO-C, PJM-W	15.1	0	0.7	1.0
MISO-N, SPP-S	1.1	0	0	0
MISO-C, PJM-E	28.3	11.7	14.4	16.1
MISO-C, SPP-S	2.0	4.7	6.0	6.0
MISO-C, SERTP	4.1	7.5	10.1	12.2
MISO-C, MISO-S	2.1	1.4	1.8	2.3
MISO-S, SPP-S	3.3	5.8	6.4	7.0
MISO-S, SERTP	11.0	0	0	0.1
MISO-S, ERCOT	0	0	0	0

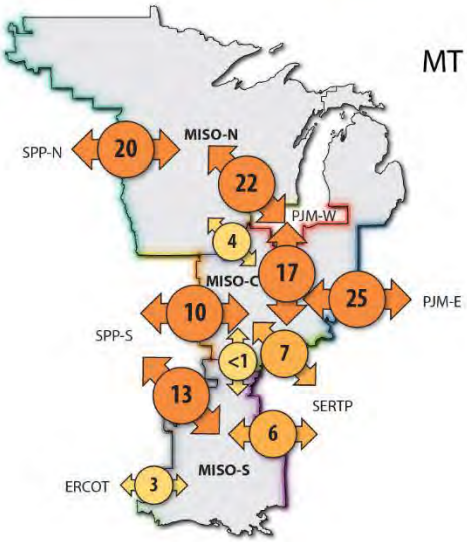
P2P Framework



Interface Capacity (GW)

REGION	EXISTING	Percentile of New Capacity 25TH	50TH	75TH
MISO-N, SPP-N	10.0	1.7	2.6	3.8
MISO-N, PJM-W	5.0	1.5	2.0	3.4
MISO-N, MISO-C	5.5	1.0	1.8	4.3
MISO-C, PJM-W	15.1	0	0	0
MISO-N, SPP-S	1.1	0	0	0
MISO-C, PJM-E	28.3	2.6	4.7	7.9
MISO-C, SPP-S	2.0	4.8	5.6	5.8
MISO-C, SERTP	4.1	5.6	6.8	7.7
MISO-C, MISO-S	2.1	1.2	1.8	2.7
MISO-S, SPP-S	3.3	4.5	5.5	6.3
MISO-S, SERTP	11.0	0	0	0
MISO-S, ERCOT	0	3.3	4.4	4.9
Nonadjacent Region Interfaces MISO-N, PJM-E	0	2.0	4.4	7.1
Nonadjacent Region Interfaces MISO-S, FRCC	0	6.2	7.3	8.6

MT Framework

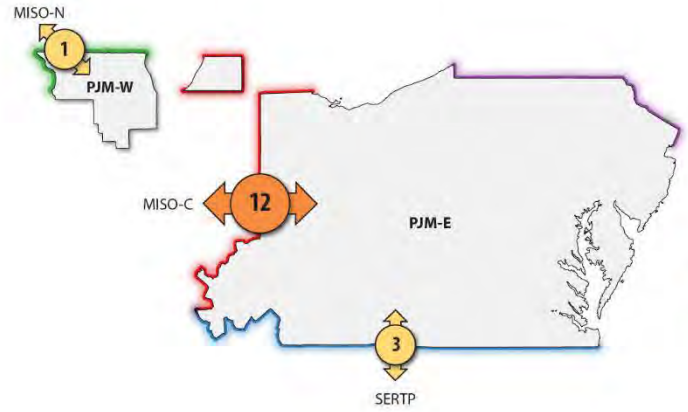


Interface Capacity (GW)

REGION	EXISTING	Percentile of New Capacity 25TH	50TH	75TH
MISO-N, SPP-N	10.0	20.3	24.8	27.8
MISO-N, PJM-W	5.0	21.8	23.4	27.5
MISO-N, MISO-C	5.5	3.8	5.0	5.5
MISO-C, PJM-W	15.1	16.5	19.7	22.8
MISO-N, SPP-S	1.1	0	0	0.1
MISO-C, PJM-E	28.3	24.7	28.0	32.6
MISO-C, SPP-S	2.0	9.9	13.8	16.8
MISO-C, SERTP	4.1	7.2	9.3	12.5
MISO-C, MISO-S	2.1	0.7	1.3	2.3
MISO-S, SPP-S	3.3	12.6	16.5	18.1
MISO-S, SERTP	11.0	5.8	9.7	11.1
MISO-S, ERCOT	0	2.6	3.7	4.6

PJM

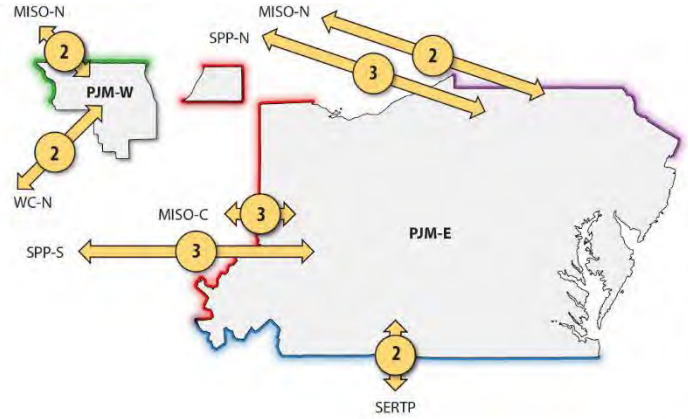
AC Framework



Interface Capacity (GW)

REGION	EXISTING	Percentile of New Capacity 25TH	50TH	75TH
PJM-W, MISO-N	5.0	1.4	2.9	4.9
PJM-E, MISO-C	28.3	11.7	14.4	16.1
PJM-E, SERTP	10.9	3.2	6.8	7.4
PJM-E, NYISO	6.6	0	0	0

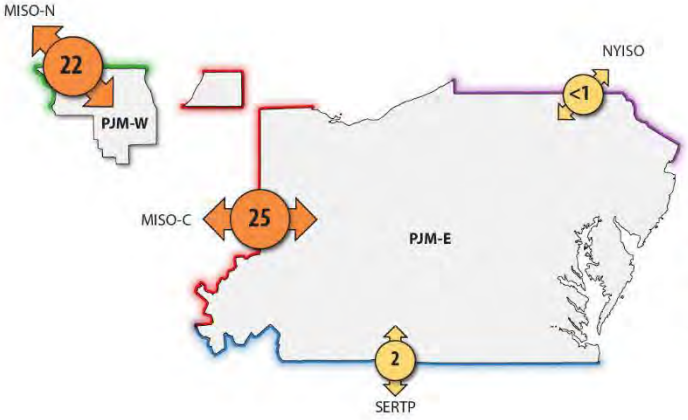
P2P Framework



Interface Capacity (GW)

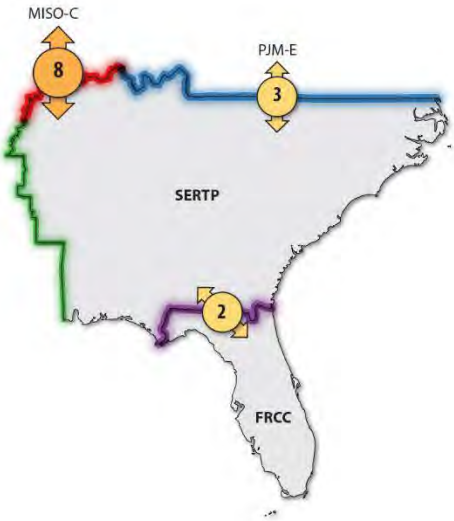
REGION	EXISTING	Percentile of New Capacity 25TH	50TH	75TH
PJM-W, MISO-N	5.0	1.5	2.0	3.4
PJM-E, MISO-C	28.3	2.6	4.7	7.9
PJM-E, SERTP	10.9	2.2	5.0	6.3
PJM-E, NYISO	6.6	0	0	0
Nonadjacent Region Interfaces				
PJM-E, MISO-N	0	2.0	4.4	7.1
PJM-E, SPP-N	0	3.4	5.2	10.0
PJM-E, SPP-S	0	3.3	4.7	7.1
PJM-W, WC-N	0	2.2	3.1	4.9

MT Framework



Interface Capacity (GW)

REGION	EXISTING	Percentile of New Capacity 25TH	50TH	75TH
PJM-W, MISO-N	5.0	21.8	23.4	27.5
PJM-E, MISO-C	28.3	24.7	28.0	32.6
PJM-E, SERTP	10.9	1.6	3.8	5.7
PJM-E, NYISO	6.6	0.9	2.4	3.7

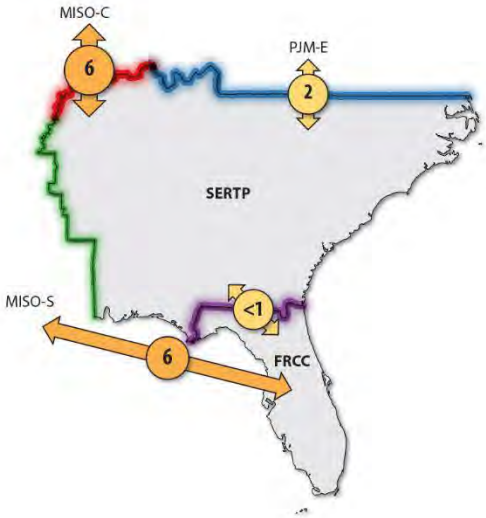


SERTP & FRCC

AC Framework

Interface Capacity (GW)

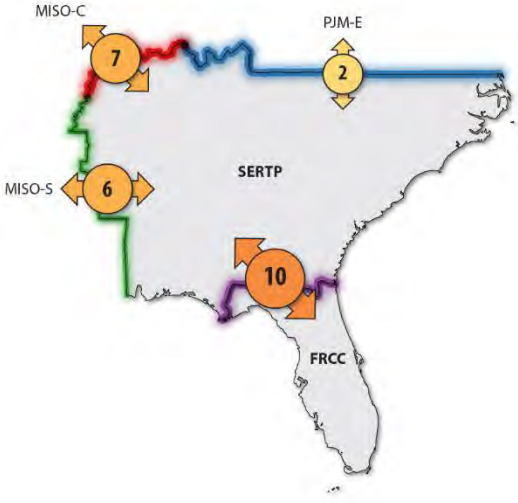
REGION	EXISTING	Percentile of New Capacity 25TH	50TH	75TH
SERTP, MISO-C	4.1	7.5	10.1	12.2
SERTP, PJM-E	10.9	3.2	6.8	7.4
SERTP, MISO-S	11.0	0	0	0.1
SERTP, FRCC	6.6	1.9	2.3	2.6



P2P Framework

Interface Capacity (GW)

REGION	EXISTING	Percentile of New Capacity 25TH	50TH	75TH
SERTP, MISO-C	4.1	5.6	6.8	7.7
SERTP, PJM-E	10.9	2.2	5.0	6.3
SERTP, MISO-S	11.0	0	0	0
SERTP, FRCC	6.6	0.1	0.8	1.7
Nonadjacent Region Interfaces				
FRCC, MISO-S	6.9	6.2	7.3	8.6



MT Framework

Interface Capacity (GW)

REGION	EXISTING	Percentile of New Capacity 25TH	50TH	75TH
SERTP, MISO-C	4.1	7.2	9.3	12.5
SERTP, PJM-E	10.9	1.6	3.8	5.7
SERTP, MISO-S	11.0	5.8	9.7	11.1
SERTP, FRCC	6.6	10.1	11.7	12.4

NYISO & ISONE

AC Framework



Interface Capacity (GW)

REGION	EXISTING	Percentile of New Capacity 25TH	50TH	75TH
NYISO, ISONE	3.5	**1.7**	1.8	2.5
NYISO, PJM-E	6.6	**0**	0	0

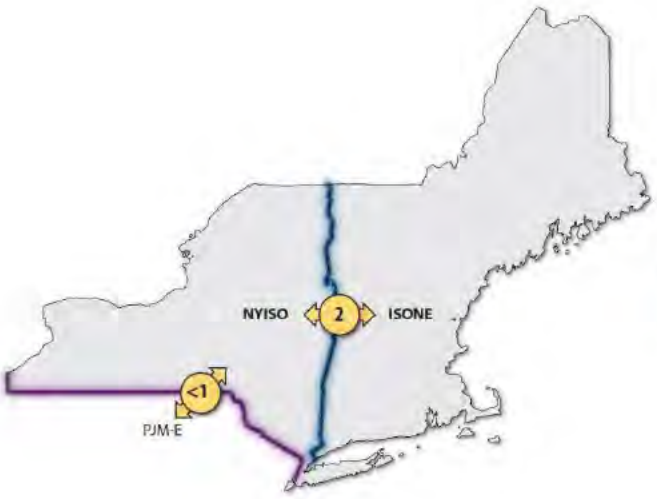
P2P Framework



Interface Capacity (GW)

REGION	EXISTING	Percentile of New Capacity 25TH	50TH	75TH
NYISO, ISONE	3.5	**1.4**	1.9	2.4
NYISO, PJM-E	6.6	**0**	0	0

MT Framework



Interface Capacity (GW)

REGION	EXISTING	Percentile of New Capacity 25TH	50TH	75TH
NYISO, ISONE	3.5	**1.6**	2.2	2.9
NYISO, PJM-E	6.6	**0.9**	2.4	3.7







GDO
GRID DEPLOYMENT OFFICE

DOE/GO-102024-6258 | October 2024

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-26-46
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	)))))	Order No. 202-26-47

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 66
NERC 2024 Interregional Transfer Capability Study, Part 1

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Interregional Transfer Capability Study (ITCS)

Strengthening Reliability Through the Energy Transformation

Transfer Capability Analysis (Part 1)

August 2024

RELIABILITY | RESILIENCE | SECURITY






3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

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Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of NERC and the six Regional Entities, is a highly reliable, resilient, and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security

Because nearly 400 million citizens in North America are counting on us

The North American BPS is made up of six Regional Entities as shown on the map and in the corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Regional Entity while associated Transmission Owners/Operators participate in another.



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

Statement of Purpose

Congress enacted legislation requiring an Interregional Transfer Capability Study (ITCS) to inform the potential need for more electric transmission capacity between regions for reliability. Signed into law in June 2023, section 322 of the Fiscal Responsibility Act of 2023[1] directs NERC, as the ERO under section 215 of the Federal Power Act[2] to conduct the ITCS:

> *The Electric Reliability Organization…in consultation with each regional entity…and each transmitting utility (as that term is defined in section 3(23) of such Act) that has facilities interconnected with a transmitting utility in a neighboring transmission planning region, shall conduct a study of total transfer capability as defined in section 37.6(b)(1)(vi) of title 18, Code of Federal Regulations, between transmission planning regions that contains the following:*
>
> *(1) Current total transfer capability, between each pair of neighboring transmission planning regions.*
> *(2) A recommendation of prudent additions to total transfer capability between each pair of neighboring transmission planning regions that would demonstrably strengthen reliability within and among such neighboring transmission planning regions.*
> *(3) Recommendations to meet and maintain total transfer capability together with such recommended prudent additions to total transfer capability between each pair of neighboring transmission planning regions.*

This congressional directive falls within the scope of NERC's obligation under section 215 to "conduct periodic assessments of the reliability and adequacy of the bulk power system in North America."[3] NERC and the six Regional Entities,[4] collectively called the ERO Enterprise, developed and executed the ITCS in collaboration with industry to address the congressional directive. The study must be filed with the Federal Energy Regulatory Commission (FERC) by December 2, 2024,[5] with a FERC public comment period to follow. This report, which builds on the *Overview of Study Need and Approach* (ITCS Overview) published in June 2024,[6] communicates the Part 1 study process details and the transfer capability analysis.

[1] H.R.3746 - 118th Congress (2023–2024): Fiscal Responsibility Act of 2023 | Congress.gov | Library of Congress
[2] 16 U.S.C. § 824o [hereafter section 215]
[3] Section 215(g). Such reliability assessments include the Long-Term Reliability Assessment, Summer Assessment, Winter Assessment, and special assessments.
[4] NERC's work with the Regional Entities is governed by Regional Delegation Agreements (RDA) on file with FERC and posted on NERC's website. See also section 215(e)(4).
[5] See Fiscal Responsibility Act (adding that, "Not later than 12 months after the end of the public comment period in subsection (b), the Federal Energy Regulatory Commission shall submit a report on its conclusions to Congress and include recommendations, if any, for statutory changes.").
[6] Readers are encouraged to review the ITCS Overview of Study Need and Approach, found here, for a more complete understanding of this Part 1 report.

Executive Summary

A Complex Grid

The North American grid is a complex machine that integrates a network of generation, transmission, and distribution systems across vast geographic areas that has evolved over many years.[7] A strong, flexible, and resilient transmission system is critical for the reliable delivery of electricity and is an essential component of grid reliability. As the ERO, NERC remains focused on assuring reliability throughout the ongoing energy transformation. Recent operational events[8] on the BPS show that more needs to be done to support energy adequacy to continuously meet customer demand. Ensuring sufficient transfer capability[9] of the transmission system to support energy adequacy[10] is the reliability gap that the ITCS seeks to address.

Study Need

NERC assessments[11] have identified the need for more transmission capacity to support the energy transformation and the ongoing electrification of the economy, including transportation, industry, and data centers. The situation is further compounded by more frequent extreme weather events. While always important, the need for reliable energy supply – in the interest of public health, safety, and security – becomes most pronounced under these conditions. The combination of these factors emphasizes the criticality of adequate and informed planning that will support future grid reliability. Transmission assessments, like the ITCS, are crucial to managing and mitigating future reliability risks. The ITCS will examine the extent of transfer capability, any prudent recommendations for additional transfer capability to strengthen reliability, and how to meet and maintain such capability as enhanced by any additions. Consistent with the ERO's mission, the ITCS focuses on reliability and will not include economic justification for new and/or upgraded transmission facilities.

KEY OBSERVATIONS

- Transfer capability varies seasonally and under different system conditions that limit transmission loading – it cannot be represented by a single number.
- Transfer capability varies widely across North America, with total import capability varying between 1% and 92% of peak load.
- Observed transfer capabilities are generally higher in the West Coast, Great Lakes, and mid-Atlantic areas, but relatively lower in the Mountain States, Great Plains, Southeast, and the Northeast regions. There is limited transfer capability between Interconnections.
- The magnitude of transfer capability is not itself a measure of energy adequacy. This will be evaluated in Part 2 of the study, which will recommend prudent additions where needed based on a holistic view of transmission and resource availability.

[7] An explanation of the electric power grid can be found here (Source: *Electricity Explained – U.S. Energy Information Administration, April 2024*).

[8] The ITCS Overview of Study Need and Approach includes examples of the critical role of transfer capability during the Western Interconnection Heatwave (2020), Winter Storm Uri (2021), and Winter Storm Elliott (2022).

[9] Transfer capability is the measure of the ability of interconnected electric systems to reliably move or transfer electric power from one area to another area by way of all transmission lines (or paths) between those areas under specific system conditions.

[10] Energy adequacy is the ability of the BPS to meet customer demand at all times.

[11] NERC's assessments can be found here.

The first ITCS document – *Overview of Study Need and Approach*[12] – was released in June 2024. It provides background and context on the study, including details regarding transfer capability calculations and the approach for recommending prudent additions, laying the foundation for the ITCS as a whole and its associated methods. As discussed therein, while an essential component of reliability is ensuring that a planned resource portfolio can deliver an adequate amount of energy at all hours of the year, the interconnected nature of the North American grid often results in energy transfers between neighboring regions. The fundamental question assessed by the ITCS is the ability of the BPS to reliably support these energy transfers.

This report – *Transfer Capability Analysis (Part 1)* – addresses the first part of the congressional directive, which mandated a transfer capability analysis between each pair of neighboring Transmission Planning Regions (TPR).[13] The results from this Part 1 analysis will be applied to Parts 2 and 3 of the study. Prudent Additions Recommendations (Part 2) of the ITCS will suggest increases to the transfer capability between neighboring TPRs to improve reliability during, for example, an extreme weather event. Meet and Maintain Recommendations (Part 3) will discuss how to meet and maintain transfer capability as enhanced by these prudent additions. Parts 2 and 3 will be issued together, and the final consolidated report will be submitted to FERC on or before December 2, 2024.

Significance of Transfer Capability

Adequate transfer capability is fundamental to the reliable operation of the BPS. Balancing Authorities may rely on their neighbors to supply energy for various purposes, including economic or policy reasons. Transfer capability is also essential under stressed operating conditions, allowing Balancing Authorities to maintain reliability by importing needed energy from their neighbors. As the resource mix becomes increasingly dependent on just-in-time and weather-dependent fuels, such as wind and solar, the ability to transfer electrical energy from areas of fuel adequacy to areas experiencing fuel constraints has become essential to maintaining reliable delivery of electricity to end-use customers. **Chapter 1** contains additional details regarding the calculation of transfer capability.

Recognizing the importance of transfer capability, there have been calls for industry regulators to require plans for a minimum transfer capability as a certain percentage of load. While the ITCS considered this approach, in practice, each TPR faces unique challenges such as its resource mix, each neighbor's resource mix, and probable weather impacts, each of which require careful consideration. As a result, a TPR with relatively low transfer capability may not experience resource deficiencies, while another TPR with relatively high transfer capability may experience resource deficiencies. A deliberate and holistic approach to coordinated resource and transmission planning will optimize the reliability provided by increased transfer capability. The recommendations for prudent additions in the Part 2 report will reflect a TPR-specific approach to transfer capability rather than a percentage-based minimum requirement.

Holistic Approach to Transfer Capability

A holistic view of the interconnected system and a thorough understanding of its behavior are essential when calculating or increasing transfer capability. When neighboring TPRs transfer energy over a highly interconnected system, the energy flows over many different lines based on the difficulty, or resistance, of traveling each route, unless there is specific equipment used to control flows. As a result, energy typically flows not only across the tie lines that directly connect the exporting (source) TPR to the importing (sink) TPR, but over many routes, some of which may be running through third-party systems. The way electrical energy flows has broad implications for calculating and using transfer capability in an interconnected system, especially when traveling over long distances. For example, maintaining and increasing transfer capability may be highly dependent on the system conditions within the source and sink TPRs as well as surrounding areas. Likewise, transfer capability does not correlate one-to-one with the rating of new or upgraded transmission facilities.

[12] The ITCS Overview of Study Need and Approach further explains transfer capability, calculation method, study assumptions, and other important study information.

[13] This is not a defined term in the NERC Glossary of Terms, but for the purposes of the ITCS, this term refers to the study regions that are described in the ITCS Overview and in **Chapter 1** of this report.

While the ITCS examines transfer capability as one side of the reliability equation, resource availability must also be considered. When extreme conditions challenge the BPS, they often impact a large geographic area. As a result, when one system is running short on resources, its neighboring systems may be facing the same dilemma simultaneously. System planners must consider various weather conditions impacting not only their own systems but also the neighboring systems they might rely on to transfer energy. Building transfer capability between systems that need more resources simultaneously will not enhance reliability during those extreme conditions. Only coordinated resource and transmission planning can ensure that the risks to the BPS are well understood and appropriately managed.

> The magnitude of transfer capability is not itself a measure of energy adequacy. This will be evaluated in Part 2 of the study, which will recommend prudent additions where needed based on a holistic view of transmission and resources.

Limitations of Transfer Capability

Planners must also carefully evaluate potential impacts of increased transfer capability. Increased transfers of energy between TPRs can benefit reliability in some situations, but large transfers also have reliability implications that must be considered. When a large amount of energy is transferred, certain aspects of reliable system operations, such as system stability, voltage control, and minimizing the potential for cascading outages, must also be considered, including the ability to withstand unplanned facility outages. This evaluation is crucial as an increased transfer capability may benefit neighboring TPRs under stressed conditions, but it can also potentially create some reliability issues that must be carefully considered in the planning process.

Finally, the transfer capability results in this report reflect the conditions studied and are not an exhaustive evaluation of the potential for energy transfers. The results are highly dependent on the assumptions, including load levels and dispatch of resources, both of which can vary significantly between seasons. For the same reasons, transfer capability can be different during non-peak periods than the peak conditions studied. This study used a set of cases representative of stressed system conditions most relevant for the Part 2 analysis. As such, the study did not attempt to maximize transfer capability values for each interface through optimal generation re-dispatch, system topology changes, or other operational measures. Consequently, higher transfer capabilities may be available under different conditions. Changes to future resource additions, resource retirements, load forecast changes, and/or transmission expansion plans have the potential to significantly alter the study results.

> Transfer capability varies seasonally and under different system conditions that limit transmission loading – it cannot be represented by a single number.

Transfer Capability Analysis (Part 1) Summary

The Part 1 transfer capability analysis between each pair of neighboring TPRs focused on two different base cases:[14]

- 2024 Summer
- 2024/25 Winter

These base cases were chosen from readily available seasonal peak load models and updated by industry to reflect future conditions. Further details regarding base case development can be found in **Chapter 1**. All electrically connected neighboring systems were evaluated, and results are presented by Interconnection proceeding from west to east as follows:

Transfer capability varies widely across North America, with total import capability varying between 1% and 92% of peak load.

- Western Interconnection (**Chapter 2**)
- Ties between the Western and Eastern Interconnections (**Chapter 3**)
- Ties between the Electric Reliability Council of Texas (ERCOT) and Eastern Interconnections (**Chapter 4**)
- Eastern Interconnection (**Chapter 5**)
- Ties between the Québec and Eastern Interconnections (**Chapter 6**)

Figure ES.1 depicts the calculated transfer capabilities for the 2024 Summer case. **Figure ES.2** similarly depicts the results from the 2024/25 Winter case.

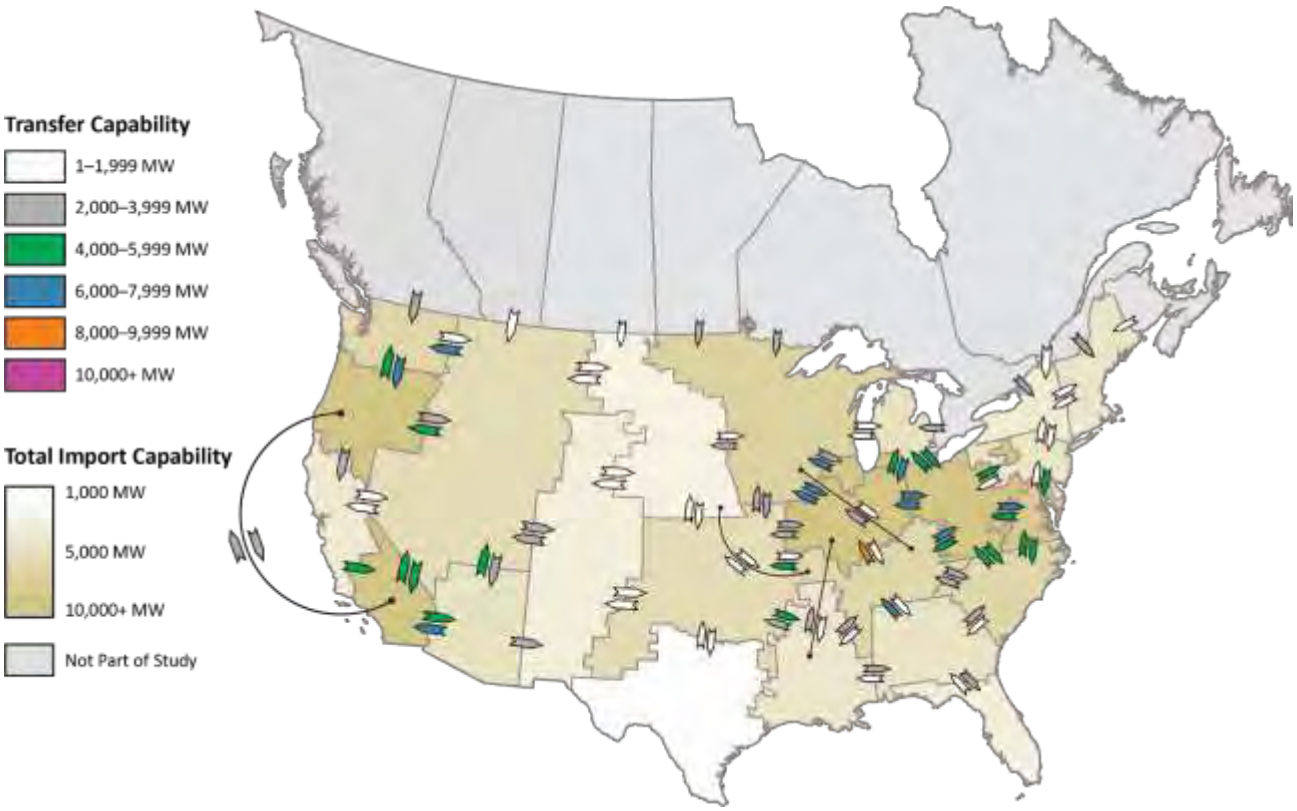


Figure ES.1: Transfer Capabilities (Summer)

[14] Base cases are computer models that simulate the behavior of the electrical system under various conditions.

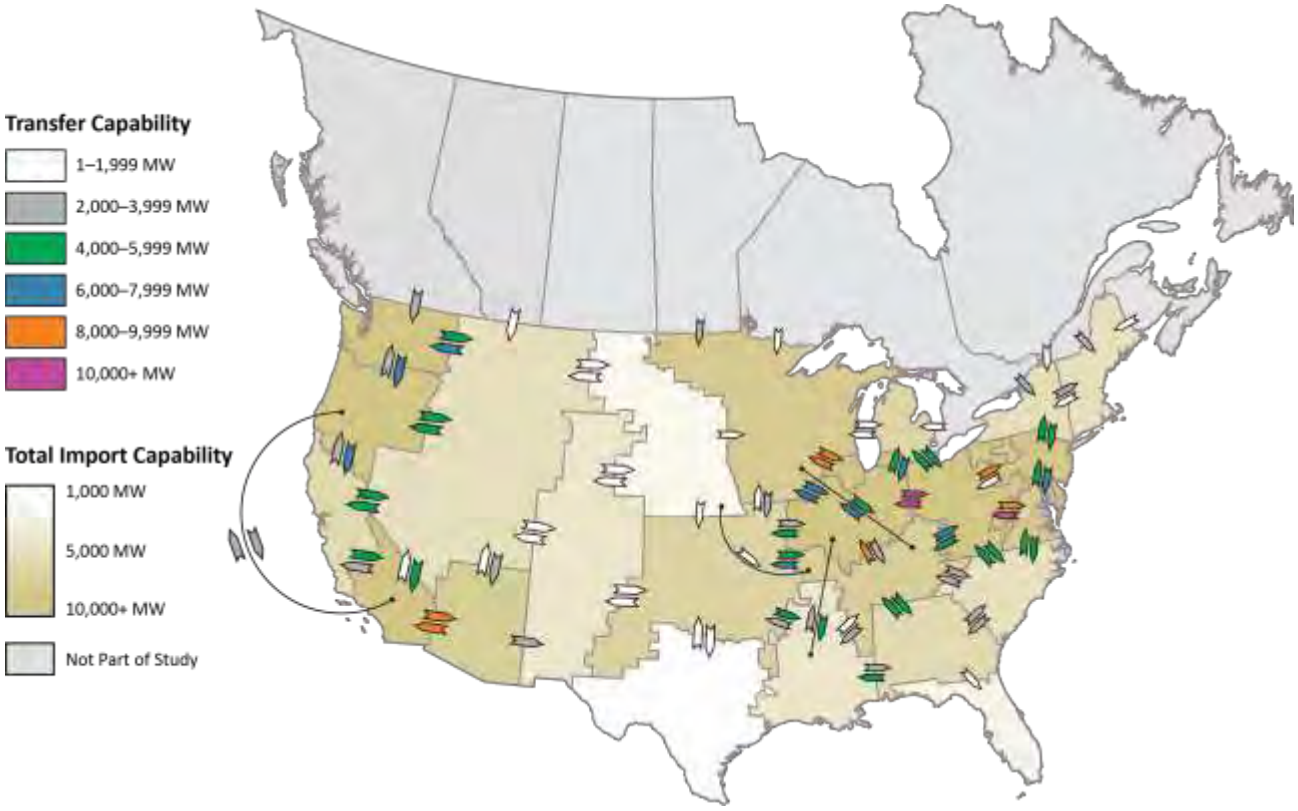


Figure ES.2: Transfer Capabilities (Winter)

Part 1 analysis also includes transfer capability between planning areas as defined by FERC's Order No. 1000.[15] Since the ITCS is being conducted under NERC's authority from section 215 and provides a more detailed reliability focus, these larger geographic areas will not be used to determine prudent additions.[16] Nonetheless, the current transfer capability results between these areas are provided for completeness in **Chapter 7**.

To more accurately reflect the ability of a TPR to simultaneously import energy from multiple neighbors, Part 1 also analyzed total import interfaces, which are provided in **Chapter 8** of this report. The use of these total import interfaces, while not part of the mandated evaluation of transfer capability between pairs of neighboring TPRs, is technically necessary to increase the accuracy of the Part 2 results by reducing the likelihood of overstating import capability.

This study is unique in terms of its geographic magnitude and overall approach to evaluating energy adequacy under extreme conditions. It revealed several challenges and highlighted associated opportunities to improve processes, data collection, and coordination for future studies. These key study opportunities are listed in **Appendix A**.

[15] More information can be found on FERC's website at www.ferc.gov.

[16] Order No. 1000 was issued by FERC in relation to Transmission Planning and Cost Allocation under FERC's authority under section 206 of the Federal Power Act. As a result, the Order No. 1000 planning regions do not, for example, include Texas.

Stakeholder Engagement and Reporting

To ensure a comprehensive and inclusive study, an ITCS Advisory Group of stakeholders was formed, including transmitting utilities across North America. Throughout the ITCS process, industry and stakeholders have been kept informed through regular updates posted on the ITCS web page, and through open project and Advisory Group meetings. To provide further opportunities for stakeholder engagement and consultation, the project has been divided into several stages, each with an accompanying report. In addition to this *Transfer Capability Analysis (Part 1)* report, the other documents are:

- ***Overview of Study Need and Approach***[17] **(completed)**: Provides background and context regarding transfer capability calculations and the approach for recommending prudent additions, laying the foundation for the ITCS as a whole and its associated methods. (published in June 2024)
- **Prudent Additions Recommendations (Part 2) and Meet and Maintain Recommendations (Part 3):** Identification of prudent additions to transfer capability between neighboring areas (Part 2) and the recommendations to meet and maintain transfer capability (Part 3). (November 2024)
- **Canadian Analysis:** A study of transfer capabilities from the United States to Canada and between Canadian provinces. While this part is outside the specific congressional directive,[18] the interconnectedness of the North American BPS[19] warrants analysis of Canada. (Q1 2025)

[17] The ITCS Overview of Study Need and Approach can be found here.

[18] H.R.3746 - 118th Congress (2023-2024): Fiscal Responsibility Act of 2023 | Congress.gov | Library of Congress

[19] The Western Interconnection includes the Canadian provinces of Alberta and British Columbia. Similarly, the Eastern Interconnection contains numerous transmission lines between the United States and Manitoba, New Brunswick, Ontario, and Saskatchewan, plus direct current (dc) connections with Québec.

Chapter 1: Part 1 Study Process Details

This section details the study design, tools, case development, and analysis parameters for calculating current transfer capability. The study details were reviewed by various industry groups, including the ITCS Advisory Group and Regional Entities' technical groups and committees.

Transmission Planning Regions

A set of interfaces was identified that included all pairs of neighboring TPRs so that transfer analysis from source (exporting) TPR to sink (importing) TPR and vice versa could be performed. In this context, only electrically connected neighboring systems were evaluated.

In general, this study's scope is interregional transfer capability analysis between source/sink TPRs.[20] As described in the ITCS Overview, during the process of defining TPRs for the purposes of this study, some areas defined in FERC's Order No. 1000,[21] which generally do not follow state boundaries, were sub-divided to provide more granular analysis of potential transfer capability limitations. The Canadian TPRs largely follow provincial boundaries. These TPRs, shown in **Figure 1.1**, have been carefully selected to identify key constraints to interregional transfer capability.

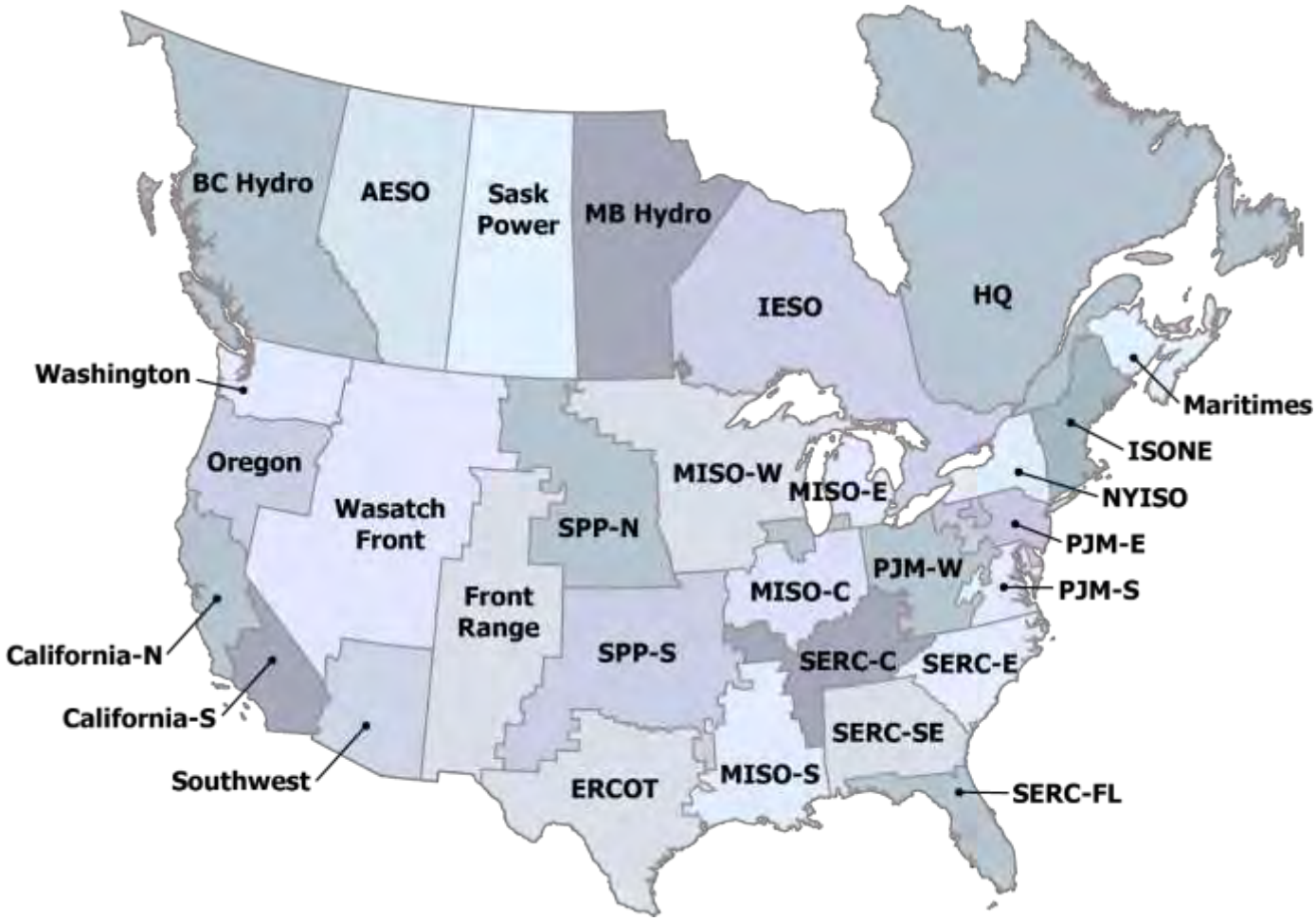


Figure 1.1: Transmission Planning Regions

[20] While the congressional directive applies to the United States, any analysis would be incomplete without a thorough understanding of the Canadian limits and available resources.

[21] More information can be found on FERC's website at www.ferc.gov.

Results for areas defined in FERC's Order No. 1000 are provided in **Chapter 7** of this report. These areas will not be part of the Part 2 Prudent Additions analysis, as the selected TPRs will provide more precise and meaningful recommendations for increases to transfer capability. While the Los Angeles Department of Water & Power (LADWP) is part of WestConnect, for the purposes of this study, LADWP was included as part of CAISO due to its geographic location within California.

To more accurately reflect the ability of a TPR to simultaneously import energy from multiple neighbors, Part 1 also analyzed total import capabilities of each TPR. Though not part of the mandate, which directed evaluation of transfer capability between neighboring TPRs, this evaluation is technically necessary to appropriately model system capability in Part 2 of the ITCS. Total import interface transfer capability results are reported in **Chapter 8**.

Canadian systems were included in this analysis to perform the transfer capability calculations from Canada to the United States. Analysis of transfer capability from the United States to Canada and between provinces will be performed subsequently, with the associated report expected to be published in the first quarter of 2025.

Total Transfer Capability

As described further in the ITCS Overview, Total Transfer Capability (TTC) is calculated as the sum of the Base Transfer Level (BTL) and First Contingency Incremental Transfer Capability (FCITC). In other words, **TTC = BTL + FCITC**. This enables a consistent calculation method across the entire study area, although TTC calculations are different than path limits which are used by some entities.

The BTL for each interface was derived, where available, from the scheduled interchange tables provided with each of the study cases. This was compared to the desired interchange for each area provided in the study cases to cross-check. Where required, adjustments were made to account for additional schedules and market re-dispatch based on load ratio where a Balancing Authority spanned multiple TPRs. For each area in the study cases where the detailed scheduled interchange tables were unavailable, BTL was approximated using the actual line flow across each interface and cross-checked against the scheduled interchange. This approach was endorsed by the ITCS Advisory Group.

The transfer analysis, which calculates the FCITC, involves simulating an incremental increase in transfers from source to sink while applying relevant contingencies and monitoring criteria (both described later), until a criteria violation is found. PowerGEM's Transmission Adequacy and Reliability Assessment (TARA) software was used for this transfer analysis. The last incremental step prior to finding a criteria violation is reported as the FCITC. A voltage screening was performed for each transfer analysis to validate the FCITC limit found. Models reflecting this transfer amount were created and screened for voltage violations using applicable contingencies. If a voltage violation was found, the FCITC was reduced, and the process repeated until the voltage violation was resolved. All results were vetted by the Regional Entities through the respective Planning Coordinators.

Base Case Development

The current transfer capability calculation was performed using relevant Eastern Interconnection and Western Interconnection base cases with consistent criteria and assumptions. Base cases are not required for the ERCOT and Québec Interconnections for this study, as they are only tied with the Eastern Interconnection via dc ties. Also, the dc ties from the Electric Reliability Council of Texas (ERCOT) to Mexico are treated as static, and the ERCOT-Mexico interface is not included in the scope of this analysis. More information can be found in the Part 1 scoping document.[22]

[22] ITCS Transfer Study Scope Part 1 (nerc.com)

System models representing Eastern and Western Interconnections were created to perform the analysis via base cases created through the MOD-032[23] process as a starting point for the following seasons:

- 2024 Summer
- 2024/25 Winter

Planning Coordinators and Transmission Planners were requested to review these cases and to supply updates, including:

- New generation – At a minimum, generation with a signed Interconnection Service Agreement was included in the applicable cases.
- Planned retirements – Generation that has retired or has announced retirement was removed from the applicable cases.
- Load forecast adjustments – Cases were updated to use the most current load forecasts.
- Resource dispatch – Changes to reflect the most current resource plans were included.
- Facility ratings – Rating changes received, including enhancements since the cases were built, were included in the cases.
- Expected long-term facility outages – Facilities expected to be out of service were removed from the applicable cases.
- Transmission system topology updates – Changes to topology, including new facility construction, were included in the cases.
- Base transfers (interchange) – New or updated firm transfers were accounted for in the cases.

Contingencies

The transfer analysis simulated contingencies, namely the unplanned outage of system elements, to ensure that the system would remain reliable during the energy transfer. The following NERC Reliability Standard TPL-001-5.1[24] category P1 contingencies (100kV and above) were used for the transfer studies, namely:

- P1-1: Loss of individual generators,
- P1-2: Loss of a single transmission line operating at 100 kV or above, and
- P1-3: Loss of a single transformer with a low-side voltage of 100 kV or above

All contingencies meeting the above criteria within the source and sink TPRs were included in each transfer study, along with all contingencies within five buses from either the source or sink TPR.

Monitored Facilities and Thresholds

Facility monitoring criteria and thresholds were established to prevent undue limitation of transfer capability results based on heavily loaded, electrically distant elements. These practices followed industry-accepted methods to ensure that transmission facilities only minimally participating in an interregional transfer do not artificially constrain the transfer limits. Additional detail regarding these criteria can be found in the Part 1 scoping document.[25] Some entities performed additional studies while monitoring lower voltage facilities to ensure there were no significant differences.

[23] MOD-032-1 (nerc.com)
[24] TPL-001-5.1 (nerc.com)
[25] ITCS Transfer Study Scope Part 1 (nerc.com)

Modeling of Transfer Participation

Transfers were simulated by scaling up the available generation in the source TPR in proportion to each unit's remaining availability, namely the difference between maximum generating capacity (P_{MAX}) and its modeled output (P_{GEN}), while scaling down the generation in the sink TPR proportional to its modeled output. Each transfer was simulated until a valid thermal limit was reached while enforcing the source system's maximum generation capacity. If the transfer did not report any transfer limits, meaning that the source TPR was resource-limited, the transfer was repeated without enforcing the source TPR's maximum generation capacity. Invalid limits, such as overloads on generating plant outlets due to not respecting these P_{MAX} values, were ignored.

Special Interface Considerations

Several interfaces have known operating procedures or other special circumstances. In many cases, these are remedial action schemes and/or flow control devices, e.g., phase angle regulators (PAR) or dc lines. The project team worked closely with industry subject matter experts to ensure that these situations were fully understood and properly reflected in the study results.

Power flows over dc lines do not change during transfer analysis; however, these lines are typically designed to carry large quantities of energy over long distances and across asynchronous Interconnections. Where an interface consists solely of dc tie lines, the TTC was calculated as the sum of the dc tie line ratings except where limitations on the ac system near the dc terminals are known to be more restrictive. Where an interface includes one or more dc tie lines as well as ac tie lines, the transfer analysis was conducted with the dc lines at the flow levels in the base cases.

Similarly, many interfaces include one or more PARs. For example, the PJM East to New York Interface is partially controlled by several PARs. Operating manuals describe how transfers across this interface are controlled, including the target percentage of flows across each line. This flow distribution was modeled in the base case development and transfer analysis to reflect the operating agreements between PJM and the New York Independent System Operator (NYISO).

Finally, there are several situations where one or more units at a power plant can connect to two different Interconnections. These units were modeled as provided in the base cases. The associated capacity was not added to the interface TTC, as this could lead to an overstatement of transfer capability, such as when the units are offline.

Study Results

As noted earlier, the TTC values below will be used in Parts 2 and 3 of the ITCS. Part 2 will recommend prudent additions to the amount of energy that can be moved or transferred between neighboring TPRs, while Part 3 will provide recommendations on how to meet and maintain transfer capability as enhanced by any prudent additions.

TTC results are highly dependent on the precise operating conditions, including dispatch, topology, load patterns, and facility ratings. This study did not attempt to optimize dispatch or topology to maximize TTC values. Observed transfer capability may be higher or lower depending on the operational conditions.

Results are presented by Interconnection for each season, proceeding from west to east as follows:

- Western Interconnection
- Ties between the Western and Eastern Interconnections
- Ties between the ERCOT and Eastern Interconnections
- Eastern Interconnection
- Ties between the Québec and Eastern Interconnections

Within the Western and Eastern Interconnections, results are generally presented from west to east, then north to south. A list of the interfaces and their ordering is included at the outset of each section.

Chapter 2: Western Interconnection Results

TTC results for the following interfaces are presented in this section:

- W1: British Columbia -> Washington
- W2: Washington <-> Oregon
- W3: Washington <-> Wasatch Front
- W4: Oregon <-> California North
- W5: Oregon <-> Wasatch Front
- W6: California North <-> California South
- W7: California North <-> Wasatch Front
- W8: California South <-> Wasatch Front
- W9: California South <-> Southwest
- W10: Alberta -> Wasatch Front
- W11: Wasatch Front <-> Southwest
- W12: Wasatch Front <-> Front Range
- W13: Southwest <-> Front Range
- W14: Oregon <-> Southern California (dc)

The interface between British Columbia and Saskatchewan will be covered in the Canadian Analysis.

Figure 2.1 depicts the calculated transfer capabilities for the 2024 Summer case. **Figure 2.2** similarly depicts the results from the 2024/25 Winter case.



Figure 2.1: Transfer Capabilities for Western Interconnection Interfaces (Summer)

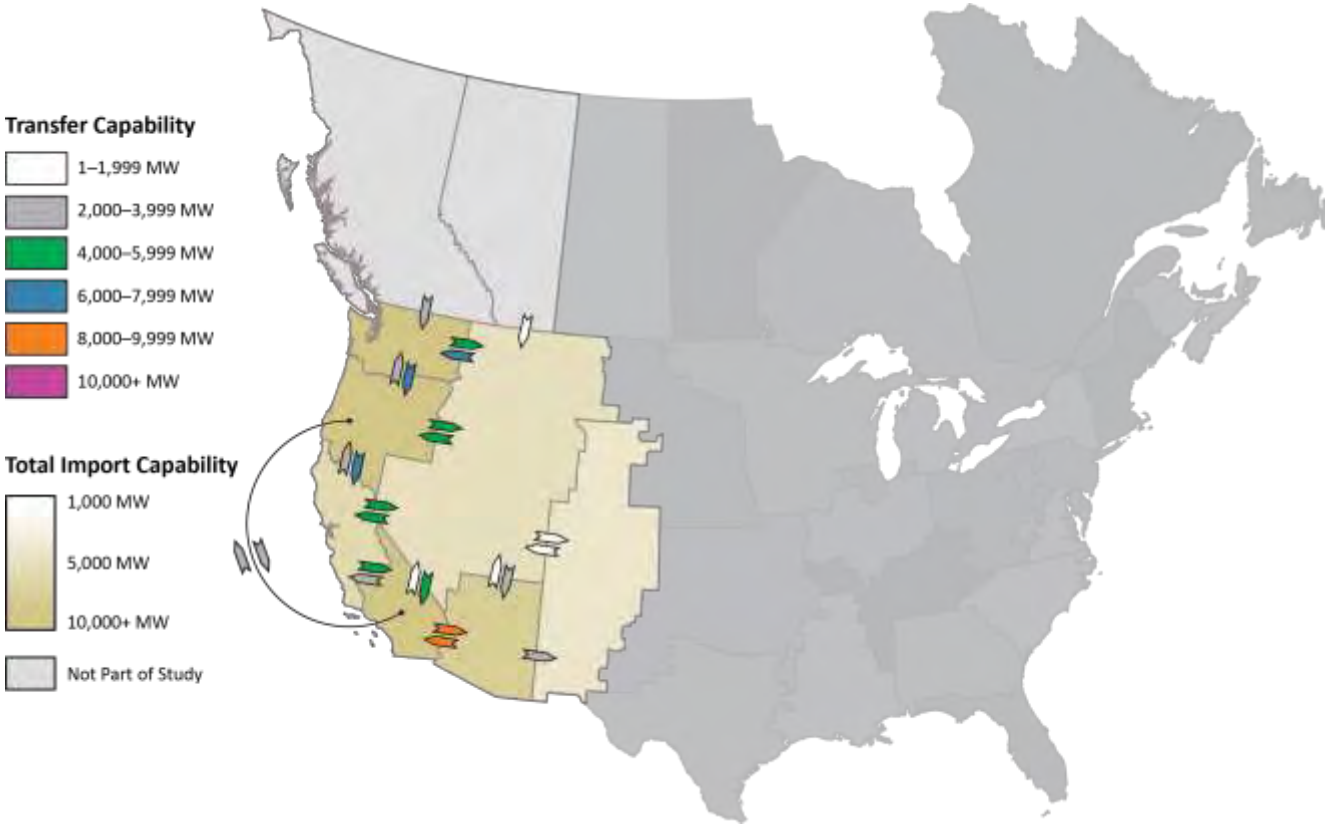


Figure 2.2: Transfer Capabilities for Western Interconnection Interfaces (Winter)

Interface W1: British Columbia -> Washington



Interface Direction	2024 Summer	2024/25 Winter
British Columbia -> Washington	2,358 MW	2,170 MW

Interface W2: Washington <-> Oregon



Interface Direction	2024 Summer	2024/25 Winter
Washington -> Oregon	7,085 MW	7,496 MW
Oregon -> Washington	4,103 MW	2,713 MW

Interface W3: Washington <-> Wasatch Front



Interface Direction	2024 Summer	2024/25 Winter
Washington -> Wasatch Front	1,925 MW	4,498 MW
Wasatch Front -> Washington	7,377 MW	7,030 MW

Interface W4: Oregon <-> California North



Interface Direction	2024 Summer	2024/25 Winter
Oregon -> California North	3,972 MW	6,175 MW
California North -> Oregon	0 MW	2,548 MW

Explanatory Note: Flows from south to north (California North to Oregon) are not typical under summer peak conditions, and generation dispatch optimization would be required to reverse the flows. Previous studies have shown a south to north transfer of ~3,675 MW.

Interface W5: Oregon <-> Wasatch Front



Interface Direction	2024 Summer	2024/25 Winter
Oregon -> Wasatch Front	2,525 MW	5,339 MW
Wasatch Front -> Oregon	4,748 MW	5,079 MW

Interface W6: California North <-> California South



Interface Direction	2024 Summer	2024/25 Winter
California North -> California South	4,647 MW	5,676 MW
California South -> California North	0 MW	3,861 MW

Explanatory Note: Flows from south to north (California South to California North) are not typical under summer peak conditions, and generation dispatch optimization would be required to reverse the flows. Previous studies have shown a south to north transfer of ~3,000 MW.

Interface W7: California North <-> Wasatch Front



Interface Direction	2024 Summer	2024/25 Winter
California North -> Wasatch Front	1,961 MW	4,980 MW
Wasatch Front -> California North	116 MW	5,388 MW

Interface W8: California South <-> Wasatch Front



Interface Direction	2024 Summer	2024/25 Winter
California South -> Wasatch Front	5,965 MW	984 MW
Wasatch Front -> California South	5,419 MW	5,568 MW

Interface W9: California South <-> Southwest



Interface Direction	2024 Summer	2024/25 Winter
California South -> Southwest	5,247 MW	8,470 MW
Southwest -> California South	7,667 MW	8,752 MW

Interface W10: Alberta -> Wasatch Front



Interface Direction	2024 Summer	2024/25 Winter
Alberta -> Wasatch Front	957 MW	1,280 MW

Interface W11: Wasatch Front <-> Southwest



Interface Direction	2024 Summer	2024/25 Winter
Wasatch Front -> Southwest	2,351 MW	2,095 MW
Southwest -> Wasatch Front	5,821 MW	1,295 MW

Interface W12: Wasatch Front <-> Front Range



Interface Direction	2024 Summer	2024/25 Winter
Wasatch Front -> Front Range	2,032 MW	1,984 MW
Front Range -> Wasatch Front	2,437 MW	477 MW

Interface W13: Southwest <-> Front Range



Interface Direction	2024 Summer	2024/25 Winter
Southwest -> Front Range	3,284 MW	3,751 MW
Front Range -> Southwest	0 MW	0 MW

Interface W14: Oregon <-> California South



Special Information: dc-only interface

Interface Direction	2024 Summer	2024/25 Winter
Oregon -> California South	3,220 MW	3,220 MW
California South -> Oregon	3,100 MW	3,100 MW

Chapter 3: Western – Eastern Interconnection Results

TTC results for the following interfaces are presented in this section:

- WE1: Wasatch Front <-> SPP North (dc)
- WE2: Front Range <-> SPP North (dc)
- WE3: Front Range <-> SPP South (dc)

The interface between Alberta and Saskatchewan will be covered in the Canadian Analysis.

Figure 3.1 depicts the calculated transfer capabilities for the 2024 Summer case. **Figure 3.2** similarly depicts the results from the 2024/25 Winter case.



Figure 3.1: Transfer Capability Between Western and Eastern Interconnections (Summer)



Figure 3.2: Transfer Capability Between Western and Eastern Interconnections (Winter)

Interface WE1: Wasatch Front <-> SPP North



Special Information: dc-only interface

Interface Direction	2024 Summer	2024/25 Winter
Wasatch Front -> SPP North	150 MW	150 MW
SPP North -> Wasatch Front	200 MW	200 MW

Interface WE2: Front Range <-> SPP North



Special Information: dc-only interface

Interface Direction	2024 Summer	2024/25 Winter
Front Range -> SPP North	510 MW	510 MW
SPP North -> Front Range	510 MW	510 MW

Interface WE3: Front Range <-> SPP South



Special Information: dc-only interface

Interface Direction	2024 Summer	2024/25 Winter
Front Range -> SPP South	410 MW	410 MW
SPP South -> Front Range	410 MW	410 MW

Chapter 4: ERCOT – Eastern Interconnection Results

TTC results for the following interfaces are presented in this section:

- TE1: ERCOT <-> SPP South (dc)

Figure 4.1 depicts the calculated transfer capabilities for the 2024 Summer case. **Figure 4.2** similarly depicts the results from the 2024/25 Winter case.



Figure 4.1: Transfer Capability Between ERCOT and Eastern Interconnections (Summer)

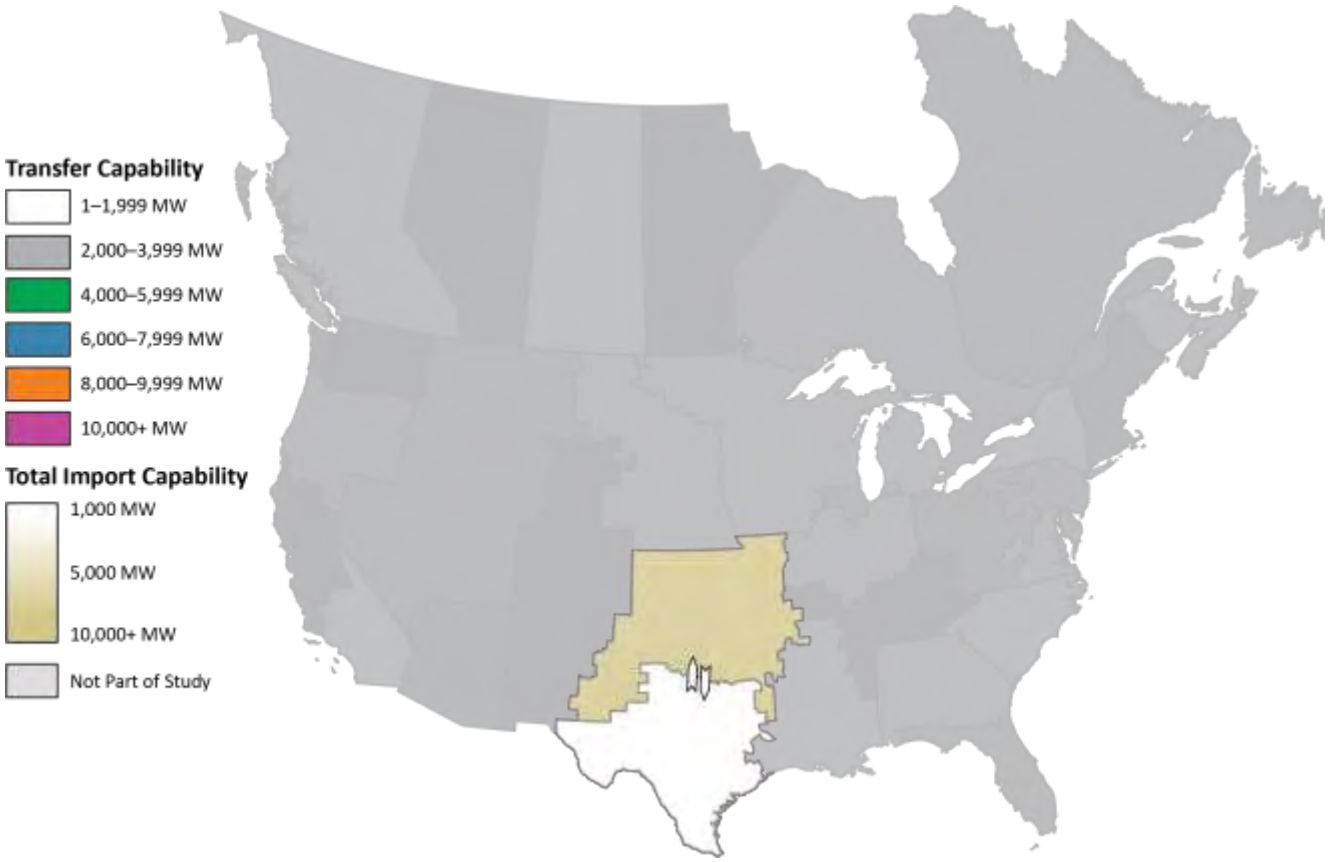


Figure 4.2: Transfer Capability Between ERCOT and Eastern Interconnections (Winter)

Interface TE1: ERCOT <-> SPP South



Special Information: dc-only interface

Interface Direction	2024 Summer	2024/25 Winter
ERCOT -> SPP South	820 MW	820 MW
SPP South -> ERCOT	820 MW	820 MW

Chapter 5: Eastern Interconnection Results

TTC results for the following interfaces are presented in this section:

- E1: Saskatchewan -> SPP North
- E2: SPP North <-> SPP South
- E3: SPP North <-> SERC Central
- E4: SPP North <-> MISO West
- E5: SPP South <-> MISO West
- E6: SPP South <-> MISO Central
- E7: SPP South <-> SERC Central
- E8: SPP South <-> MISO South
- E9: Manitoba -> MISO West
- E10: Ontario -> MISO West
- E11: MISO West <-> MISO East (dc)
- E12: MISO West <-> PJM West
- E13: MISO West <-> MISO Central
- E14: MISO West <-> SERC Central
- E15: MISO Central <-> MISO East
- E16: MISO Central <-> PJM West
- E17: MISO Central <-> SERC Central
- E18: MISO Central <-> MISO South
- E19: MISO South <-> SERC Central
- E20: MISO South <-> SERC Southeast
- E21: Ontario -> MISO East
- E22: MISO East <-> PJM West
- E23: SERC Central <-> PJM West
- E24: SERC Central <-> SERC East
- E25: SERC-Central <-> SERC Southeast
- E26: SERC Southeast <-> SERC Florida
- E27: SERC Southeast <-> SERC East
- E28: SERC East <-> PJM West
- E29: SERC East <-> PJM South
- E30: PJM West <-> PJM East
- E31: PJM West <-> PJM South
- E32: PJM East <-> PJM South
- E33: PJM East <-> New York
- E34: Ontario -> New York
- E35: New York <-> New England
- E36: Maritimes -> New England

Interfaces between Saskatchewan and Manitoba, and between Manitoba and Ontario will be covered in the Canadian Analysis.

Figure 5.1 depicts the calculated transfer capabilities for the 2024 Summer case. **Figure 5.2** similarly depicts the results from the 2024/25 Winter case.

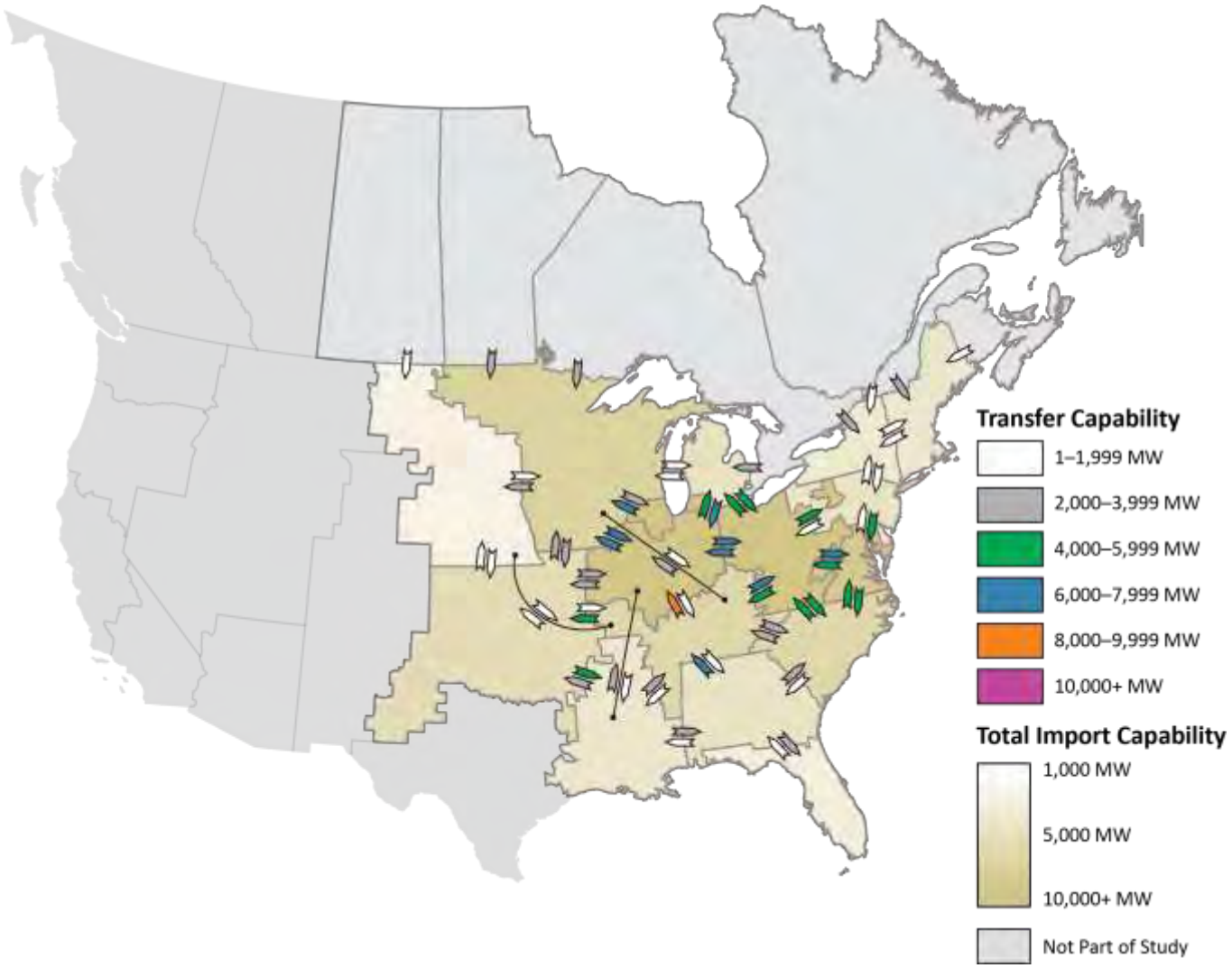


Figure 5.1: Transfer Capabilities of Eastern Interconnection Interfaces (Summer)

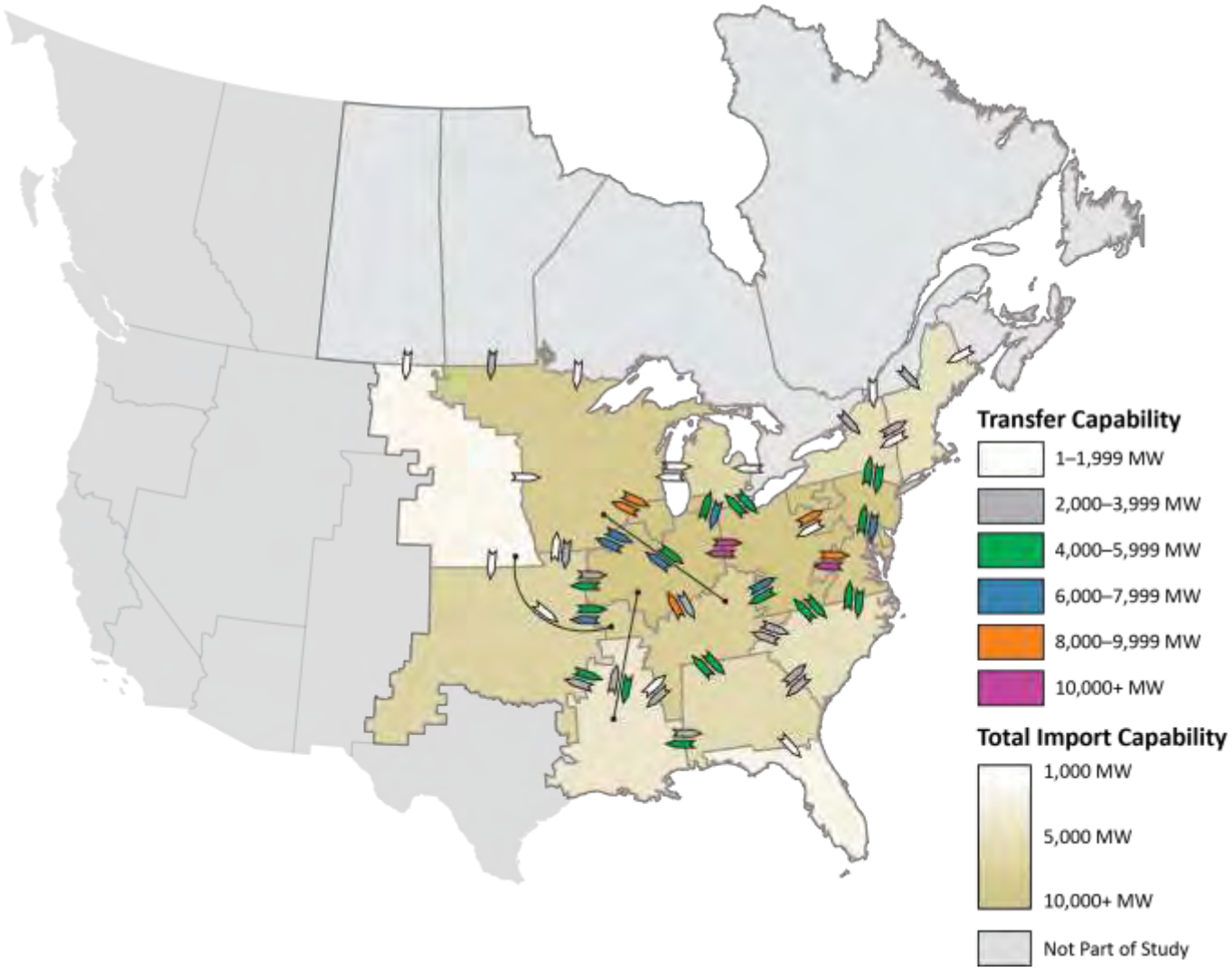


Figure 5.2: Transfer Capabilities of Eastern Interconnection Interfaces (Winter)

Interface E1: Saskatchewan -> SPP North



Interface Direction	2024 Summer	2024/25 Winter
Saskatchewan -> SPP North	165 MW	663 MW

Interface E2: SPP North <-> SPP South



Interface Direction	2024 Summer	2024/25 Winter
SPP North -> SPP South	1,501 MW	1,785 MW
SPP South -> SPP North	1,705 MW	0 MW

Explanatory Note: Under the studied winter peak conditions, transfers from SPP South to SPP North were limited by a constraint that will be relieved by a new construction project expected to be in-service in late 2024 or early 2025.

Interface E3: SPP North <-> SERC Central



Interface Direction	2024 Summer	2024/25 Winter
SPP North -> SERC Central	128 MW	1,102 MW
SERC Central -> SPP North	1,183 MW	0 MW

Explanatory Note: Under the studied winter peak conditions, transfers from SERC Central to SPP North were limited by a constraint that will be relieved by a new construction project expected to be in-service in late 2024 or early 2025.

Interface E4: SPP North <-> MISO West



Interface Direction	2024 Summer	2024/25 Winter
SPP North -> MISO West	623 MW	778 MW
MISO West -> SPP North	2,209 MW	0 MW

Explanatory Note: Under the studied winter peak conditions, transfers from MISO West to SPP North were limited by a constraint that will be relieved by a new construction project expected to be in-service in late 2024 or early 2025.

Interface E5: SPP South <-> MISO West



Interface Direction	2024 Summer	2024/25 Winter
SPP South -> MISO West	3,323 MW	1,196 MW
MISO West -> SPP South	2,086 MW	3,801 MW

Interface E6: SPP South <-> MISO Central



Interface Direction	2024 Summer	2024/25 Winter
SPP South -> MISO Central	2,481 MW	2,420 MW
MISO Central -> SPP South	3,873 MW	5,635 MW

Interface E7: SPP South <-> SERC Central



Interface Direction	2024 Summer	2024/25 Winter
SPP South -> SERC Central	859 MW	5,591 MW
SERC Central -> SPP South	5,042 MW	6,445 MW

Interface E8: SPP South <-> MISO South



Interface Direction	2024 Summer	2024/25 Winter
SPP South -> MISO South	4,295 MW	4,336 MW
MISO South -> SPP South	3,033 MW	3,878 MW

Interface E9: Manitoba -> MISO West



Interface Direction	2024 Summer	2024/25 Winter
Manitoba -> MISO West	3,772 MW	3,633 MW

Interface E10: Ontario -> MISO West



Interface Direction	2024 Summer	2024/25 Winter
Ontario -> MISO West	2,424 MW	1,862 MW

Interface E11: MISO West <-> MISO East



Special Information: dc-only interface

Interface Direction	2024 Summer	2024/25 Winter
MISO West -> MISO East	160 MW	160 MW
MISO East -> MISO West	160 MW	160 MW

Interface E12: MISO West <-> PJM West



Interface Direction	2024 Summer	2024/25 Winter
MISO West -> PJM West	2,518 MW	8,011 MW
PJM West -> MISO West	7,791 MW	9,086 MW

Interface E13: MISO West <-> MISO Central



Interface Direction	2024 Summer	2024/25 Winter
MISO West -> MISO Central	6,199 MW	7,306 MW
MISO Central -> MISO West	7,602 MW	7,341 MW

Interface E14: MISO West <-> SERC Central



Interface Direction	2024 Summer	2024/25 Winter
MISO West -> SERC Central	150 MW	4,141 MW
SERC Central -> MISO West	3,671 MW	6,877 MW

Interface E15: MISO Central <-> MISO East



Interface Direction	2024 Summer	2024/25 Winter
MISO Central -> MISO East	4,864 MW	5,585 MW
MISO East -> MISO Central	6,344 MW	6,531 MW

Interface E16: MISO Central <-> PJM West



Interface Direction	2024 Summer	2024/25 Winter
MISO Central -> PJM West	6,572 MW	10,790 MW
PJM West -> MISO Central	6,986 MW	20,449 MW

Interface E17: MISO Central <-> SERC Central



Interface Direction	2024 Summer	2024/25 Winter
MISO Central -> SERC Central	235 MW	3,903 MW
SERC Central -> MISO Central	8,288 MW	8,441 MW

Interface E18: MISO Central <-> MISO South



Interface Direction	2024 Summer	2024/25 Winter
MISO Central -> MISO South	1,797 MW	4,067 MW
MISO South -> MISO Central	2,117 MW	1,093 MW

Interface E19: MISO South <-> SERC Central



Interface Direction	2024 Summer	2024/25 Winter
MISO South -> SERC Central	2,468 MW	1,361 MW
SERC Central -> MISO South	1,457 MW	3,342 MW

Interface E20: MISO South <-> SERC Southeast



Interface Direction	2024 Summer	2024/25 Winter
MISO South -> SERC Southeast	3,600 MW	3,392 MW
SERC Southeast -> MISO South	1,638 MW	4,028 MW

Interface E21: Ontario -> MISO East



Interface Direction	2024 Summer	2024/25 Winter
Ontario -> MISO East	2,348 MW	1,649 MW

Interface E22: MISO East <-> PJM West



Interface Direction	2024 Summer	2024/25 Winter
MISO East -> PJM West	5,603 MW	5,940 MW
PJM West -> MISO East	4,345 MW	5,608 MW

Interface E23: SERC Central <-> PJM West



Interface Direction	2024 Summer	2024/25 Winter
SERC Central -> PJM West	6,646 MW	6,710 MW
PJM West -> SERC Central	5,444 MW	5,786 MW

Interface E24: SERC Central <-> SERC East



Interface Direction	2024 Summer	2024/25 Winter
SERC Central -> SERC East	2,419 MW	3,311 MW
SERC East -> SERC Central	3,257 MW	2,675 MW

Interface E25: SERC Central <-> SERC Southeast



Interface Direction	2024 Summer	2024/25 Winter
SERC Central -> SERC Southeast	1,095 MW	5,387 MW
SERC Southeast -> SERC Central	6,579 MW	4,639 MW

Interface E26: SERC Southeast <-> SERC Florida



Interface Direction	2024 Summer	2024/25 Winter
SERC Southeast -> SERC Florida	2,958 MW	1,807 MW
SERC Florida -> SERC Southeast	1,322 MW	0 MW

Explanatory Note: Flows from South to North (SERC Florida to SERC Southeast) are not typical under winter peak conditions.

Interface E27: SERC Southeast <-> SERC East



Interface Direction	2024 Summer	2024/25 Winter
SERC Southeast -> SERC East	2,397 MW	3,669 MW
SERC East -> SERC Southeast	1,703 MW	3,536 MW

Interface E28: SERC East <-> PJM West



Interface Direction	2024 Summer	2024/25 Winter
SERC East -> PJM West	5,185 MW	4,448 MW
PJM West -> SERC East	5,318 MW	4,286 MW

Interface E29: SERC East <-> PJM South



Interface Direction	2024 Summer	2024/25 Winter
SERC East -> PJM South	4,596 MW	4,963 MW
PJM South -> SERC East	4,665 MW	5,463 MW

Interface E30: PJM West <-> PJM East



Interface Direction	2024 Summer	2024/25 Winter
PJM West -> PJM East	4,762 MW	9,815 MW
PJM East -> PJM West	1,443 MW	166 MW

Interface E31: PJM West <-> PJM South



Interface Direction	2024 Summer	2024/25 Winter
PJM West -> PJM South	7,041 MW	9,035 MW
PJM South -> PJM West	5,347 MW	10,942 MW

Interface E32: PJM East <-> PJM South



Interface Direction	2024 Summer	2024/25 Winter
PJM East -> PJM South	5,094 MW	6,770 MW
PJM South -> PJM East	1,605 MW	4,166 MW

Interface E33: PJM East <-> New York



Interface Direction	2024 Summer	2024/25 Winter
PJM East -> New York	1,356 MW	4,814 MW
New York -> PJM East	913 MW	4,019 MW

Interface E34: Ontario -> New York



Interface Direction	2024 Summer	2024/25 Winter
Ontario -> New York	2,286 MW	2,719 MW

Interface E35: New York <-> New England



Interface Direction	2024 Summer	2024/25 Winter
New York -> New England	1,303 MW	2,432 MW
New England -> New York	1,660 MW	1,359 MW

Interface E36: Maritimes -> New England



Interface Direction	2024 Summer	2024/25 Winter
Maritimes -> New England	1,127 MW	1,265 MW

Chapter 6: Québec – Eastern Interconnection Results

TTC results for the following interfaces are presented in this section:

- QE1: Québec -> New York (dc)
- QE2: Québec -> New England (dc)

Interfaces between Québec and Ontario and between Québec and the Maritimes will be covered in the Canadian Analysis.

Figure 6.1 depicts the calculated transfer capabilities for the 2024 Summer case. **Figure 6.2** similarly depicts the results from the 2024/25 Winter case.



Figure 6.1: Transfer Capability Between Québec and Eastern Interconnections (Summer)



Figure 6.2: Transfer Capability Between Québec and Eastern Interconnections (Winter)

Interface QE1: Québec -> New York



Special Information: dc-only interface

Interface Direction	2024 Summer	2024/25 Winter
Québec -> New York	1,000 MW	1,000 MW

Interface QE2: Québec -> New England



Special Information: dc-only interface

Interface Direction	2024 Summer	2024/25 Winter
Québec -> New England	2,225 MW	2,225 MW

Chapter 7: Supplemental Results Between Order 1000 Areas

The ITCS analyzed an additional set of transfers between areas defined in FERC's Order 1000 (see **Figure 7.1**). While these larger geographic areas will not be used for the purpose of determining prudent additions, the current transfer capability results are provided for completeness. Where results were previously presented, they are not repeated here. TTC results for the following interfaces are presented in this section:

- W1001: British Columbia -> Northern Grid
- W1002: Alberta -> Northern Grid
- W1003: Northern Grid <-> California ISO
- W1004: Northern Grid <-> West Connect
- W1005: California ISO <-> West Connect
- E1001: Saskatchewan -> SPP
- E1002: SPP <-> MISO
- E1003: SPP <-> SERTP
- E1004: Manitoba -> MISO
- E1005: Ontario -> MISO
- E1006: MISO <-> PJM
- E1007: MISO <-> SERTP
- E1008: SERTP <-> PJM
- E1009: SERTP <-> SCRTP
- E1010: SERTP <-> FRCC
- E1011: PJM <-> New York

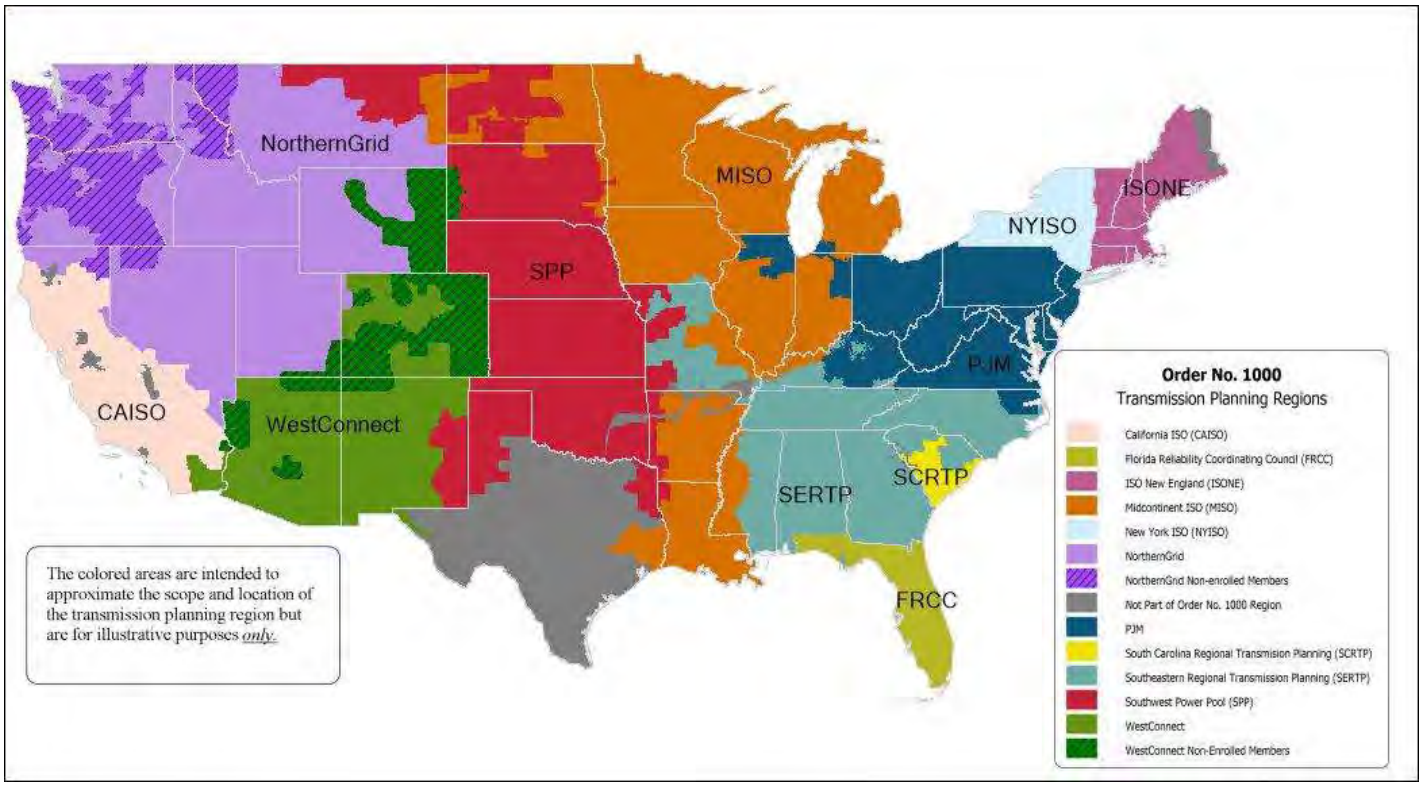


Figure 7.1: Areas Defined in FERC Order 1000

Interface W1001: British Columbia -> Northern Grid

Interface Direction	2024 Summer	2024/25 Winter
British Columbia -> Northern Grid	2,435 MW	2,164 MW

Interface W1002: Alberta -> Northern Grid

Interface Direction	2024 Summer	2024/25 Winter
Alberta -> Northern Grid	981 MW	1,286 MW

Interface W1003: Northern Grid <-> California ISO

Interface Direction	2024 Summer	2024/25 Winter
Northern Grid -> California ISO	4,140 MW	8,705 MW
California ISO -> Northern Grid	1,985 MW	5,208 MW

Interface W1004: Northern Grid <-> West Connect

Interface Direction	2024 Summer	2024/25 Winter
Northern Grid -> West Connect	2,842 MW	3,326 MW
West Connect -> Northern Grid	5,710 MW	1,865 MW

Interface W1005: California ISO <-> West Connect

Interface Direction	2024 Summer	2024/25 Winter
California ISO -> West Connect	2,534 MW	2,375 MW
West Connect -> California ISO	2,967 MW	3,912 MW

Interface E1001: Saskatchewan -> SPP

Interface Direction	2024 Summer	2024/25 Winter
Saskatchewan -> SPP	0 MW	665 MW

Interface E1002: SPP <-> MISO

Interface Direction	2024 Summer	2024/25 Winter
SPP -> MISO	7,058 MW	1,513 MW
MISO -> SPP	5,308 MW	6,403 MW

Interface E1003: SPP <-> SERTP

Interface Direction	2024 Summer	2024/25 Winter
SPP -> SERTP	4,857 MW	2,814 MW
SERTP -> SPP	2,822 MW	6,324 MW

Interface E1004: Manitoba -> MISO

Interface Direction	2024 Summer	2024/25 Winter
Manitoba -> MISO	3,058 MW	3,058 MW

Interface E1005: Ontario -> MISO

Interface Direction	2024 Summer	2024/25 Winter
Ontario -> MISO	2,419 MW	1,834 MW

Interface E1006: MISO <-> PJM

Interface Direction	2024 Summer	2024/25 Winter
MISO -> PJM	5,593 MW	12,552 MW
PJM -> MISO	9,146 MW	10,771 MW

Interface E1007: MISO <-> SERTP

Interface Direction	2024 Summer	2024/25 Winter
MISO -> SERTP	6,976 MW	9,543 MW
SERTP -> MISO	0 MW	9,801 MW

Interface E1008: SERTP <-> PJM

Interface Direction	2024 Summer	2024/25 Winter
SERTP -> PJM	8,609 MW	9,782 MW
PJM -> SERTP	7,704 MW	7,905 MW

Interface E1009: SERTP <-> SCRTP

Interface Direction	2024 Summer	2024/25 Winter
SERTP -> SCRTP	1,767 MW	1,948 MW
SCRTP -> SERTP	2,415 MW	2,335 MW

Interface E1010: SERTP <-> FRCC

Interface Direction	2024 Summer	2024/25 Winter
SERTP -> FRCC	2,918 MW	1,803 MW
FRCC -> SERTP	1,058 MW	0 MW

Interface E1011: PJM <-> New York

Interface Direction	2024 Summer	2024/25 Winter
PJM -> New York	635 MW	858 MW
New York -> PJM	3,136 MW	3,394 MW

Chapter 8: Supplemental Total Import Interface Limits

The ITCS also analyzed an additional set of transfers into each TPR. These total import interfaces analyze the simultaneous transfers into a TPR from all its neighbors. In instances where the calculated total import interface transfer capability was lower than that from any neighboring TPR, the highest neighbor-to-neighbor results were reported to avoid understating the total import capability. The definitions of these interfaces exclude connections via dc-only interfaces, which can typically be scheduled independently. TTC results for the following interfaces are presented in this section:

- WTI01: Into Washington
- WTI02: Into Oregon
- WTI03: Into California North
- WTI04: Into California South
- WTI05: Into Wasatch Front
- WTI06: Into Southwest
- WTI07: Into Front Range
- ETI01: Into SPP North
- ETI02: Into SPP South
- ETI03: Into MISO West
- ETI04: Into MISO Central
- ETI05: Into MISO South
- ETI06: Into MISO East
- ETI07: Into SERC Central
- ETI08: Into SERC Southeast
- ETI09: Into SERC Florida
- ETI10: Into SERC East
- ETI11: Into PJM West
- ETI12: Into PJM East
- ETI13: Into PJM South
- ETI14: Into New York
- ETI15: Into New England

Interface WTI01: Into Washington



Interface Direction	2024 Summer	2024/25 Winter
Into Washington TTC	7,377 MW[26]	10,297 MW
Percentage of Peak Load	43%	50%

Interface WTI02: Into Oregon



Interface Direction	2024 Summer	2024/25 Winter
Into Oregon TTC	8,004 MW	7,534 MW
dc-only interfaces	3,100 MW	3,100 MW
Total of TTC and dc-only interfaces	11,104 MW	10,634 MW
Percentage of Peak Load	92%	89%

[26] Value is from the Wasatch Front to Washington interface, as the total import interface calculation was more limiting.

Interface WTI03: Into California North



Interface Direction	2024 Summer	2024/25 Winter
Into California North TTC	3,972 MW[27]	6,631 MW
Percentage of Peak Load	14%	29%

Interface WTI04: Into California South



Interface Direction	2024 Summer	2024/25 Winter
Into California South TTC	7,829 MW	11,288 MW
dc-only interfaces	3,220 MW	3,220 MW
Total of TTC and dc-only interfaces	11,049 MW	14,508 MW
Percentage of Peak Load	28%	69%

[27] Value is from the Oregon to California North interface, as the total import interface calculation was more limiting.

Interface WTI05: Into Wasatch Front



Interface Direction	2024 Summer	2024/25 Winter
Into Wasatch Front TTC	5,965 MW[28]	5,558 MW
dc-only interfaces	200 MW	200 MW
Total of TTC and dc-only interfaces	6,165 MW	5,758 MW
Percentage of Peak Load	23%	35%

Interface WTI06: Into Southwest



Interface Direction	2024 Summer	2024/25 Winter
Into Southwest TTC	5,247 MW[29]	8,470 MW[30]
Percentage of Peak Load	22%	66%

[28] Value is from the California South to Wasatch Front interface, as the total import interface calculation was more limiting.
[29] Value is from the California South to Southwest interface, as the total import interface calculation was more limiting.
[30] Value is from the California South to Southwest interface, as the total import interface calculation was more limiting.

Interface WTI07: Into Front Range



Interface Direction	2024 Summer	2024/25 Winter
Into Front Range TTC	3,284 MW[31]	3,751 MW[32]
dc-only interfaces	920 MW	920 MW
Total of TTC and dc-only interfaces	4,204 MW	4,671 MW
Percentage of Peak Load	21%	30%

[31] Value is from the Southwest to Front Range interface, as the total import interface calculation was more limiting.
[32] Value is from the Southwest to Front Range interface, as the total import interface calculation was more limiting.

Interface ETI01: Into SPP North



Interface Direction	2024 Summer	2024/25 Winter
Into SPP North TTC	2,209 MW[33]	663 MW[34]
dc-only interfaces	660 MW	660 MW
Total of TTC and dc-only interfaces	2,869 MW	1,323 MW
Percentage of Peak Load	21%	11%

[33] Value is from the MISO West to SPP North interface, as the total import interface calculation was more limiting.
[34] Value is from the Saskatchewan to SPP North interface, as the total import interface calculation was more limiting.

Interface ETI02: Into SPP South



Interface Direction	2024 Summer	2024/25 Winter
Into SPP South TTC	5,042 MW[35]	6,445 MW[36]
dc-only interfaces	1,230 MW	1,230 MW
Total of TTC and dc-only interfaces	6,272 MW	7,675 MW
Percentage of Peak Load	13%	20%

[35] Value is from the SERC Central to SPP South interface, as the total import interface calculation was more limiting.
[36] Value is from the SERC Central to SPP South interface, as the total import interface calculation was more limiting.

Interface ETI03: Into MISO West



Interface Direction	2024 Summer	2024/25 Winter
Into MISO West TTC	7,791 MW[37]	9,086 MW[38]
dc-only interfaces	160 MW	160 MW
Total of TTC and dc-only interfaces	7,951 MW	9,246 MW
Percentage of Peak Load	19%	26%

Interface ETI04: Into MISO Central



Interface Direction	2024 Summer	2024/25 Winter
Into MISO Central TTC	12,714 MW	20,449 MW[39]
Percentage of Peak Load	35%	63%

[37] Value is from the PJM West to MISO West interface, as the total import interface calculation was more limiting.
[38] Value is from the PJM West to MISO West interface, as the total import interface calculation was more limiting.
[39] Value is from the PJM West to MISO Central interface, as the total import interface calculation was more limiting.

Interface ETI05: Into MISO South



Interface Direction	2024 Summer	2024/25 Winter
Into MISO South TTC	4,295 MW[40]	4,336 MW[41]
Percentage of Peak Load	12%	13%

Interface ETI06: Into MISO East



Interface Direction	2024 Summer	2024/25 Winter
Into MISO East TTC	5,139 MW	7,019 MW
dc-only interfaces	160 MW	160 MW
Total of TTC and dc-only interfaces	5,299 MW	7,179 MW
Percentage of Peak Load	25%	44%

[40] Value is from the SPP South to MISO South interface, as the total import interface calculation was more limiting.
[41] Value is from the SPP South to MISO South interface, as the total import interface calculation was more limiting.

Interface ETI07: Into SERC Central



Interface Direction	2024 Summer	2024/25 Winter
Into SERC Central TTC	6,878 MW	8,443 MW
Percentage of Peak Load	15%	18%

Interface ETI08: Into SERC Southeast



Interface Direction	2024 Summer	2024/25 Winter
Into SERC Southeast TTC	4,900 MW	6,525 MW
Percentage of Peak Load	11%	15%

Interface ETI09: Into SERC Florida



Interface Direction	2024 Summer	2024/25 Winter
Into SERC Florida TTC	2,958 MW	1,807 MW
Percentage of Peak Load	6%	4%

Interface ETI10: Into SERC East



Interface Direction	2024 Summer	2024/25 Winter
Into SERC East TTC	6,959 MW	5,463 MW[42]
Percentage of Peak Load	16%	12%

[42] Value is from PJM South to SERC East interface, as the total import interface calculation was more limiting.

Interface ETI11: Into PJM West



Interface Direction	2024 Summer	2024/25 Winter
Into PJM West TTC	21,773 MW	10,942 MW[43]
Percentage of Peak Load	28%	16%

Interface ETI12: Into PJM East



Interface Direction	2024 Summer	2024/25 Winter
Into PJM East TTC	4,762 MW[44]	9,815 MW[45]
Percentage of Peak Load	11%	28%

[43] Value is from the PJM South to PJM West interface, as the total import interface calculation was more limiting.
[44] Value is from the PJM West to PJM East interface, as the total import interface calculation was more limiting.
[45] Value is from the PJM West to PJM East interface, as the total import interface calculation was more limiting.

Interface ETI13: Into PJM South



Interface Direction	2024 Summer	2024/25 Winter
Into PJM South TTC	9,578 MW	9,035 MW[46]
Percentage of Peak Load	28%	27%

Interface ETI14: Into New York



Interface Direction	2024 Summer	2024/25 Winter
Into New York TTC	2,802 MW	4,814 MW[47]
dc-only interfaces	1,000 MW	1,000 MW
Total of TTC and dc-only interfaces	3,802 MW	5,814 MW
Percentage of Peak Load	12%	24%

[46] Value is from the PJM West to PJM South interface, as the total import interface calculation was more limiting.
[47] Value is from the PJM East to New York interface, as the total import interface calculation was more limiting.

Interface ETI15: Into New England



Interface Direction	2024 Summer	2024/25 Winter
Into New England TTC	2,313 MW	3,033 MW
dc-only interfaces	2,225 MW	2,225 MW
Total of TTC and dc-only interfaces	4,538 MW	5,258 MW
Percentage of Peak Load	19%	25%

Chapter 9: Acknowledgements

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Appendix A: Key Study Opportunities

Observation 1: There is an opportunity to develop guidance for subdividing large areas and standardizing data sources for future studies.
One challenge was selecting appropriately sized and electrically connected TPRs. It is essential to strike the right balance to identify significant limitations of interregional transfers. As the BPS evolves, these TPRs should be reviewed and modified as appropriate. In a few instances where Balancing Authorities are split into multiple TPRs, there are opportunities to enhance available data to more efficiently account for each TPR, improving the data quality in future studies.

Observation 2: There is an opportunity to improve coordination with NERC's Long-Term Reliability Assessment (LTRA) process.
Some differences in load forecasts and resource assumptions were noted when comparing study cases to LTRA data. Standardizing case-building processes and associated content could ensure consistency and improve the efficiency of future studies.

Observation 3: Future studies may need special cases to study additional conditions.
This transfer analysis used cases designed for transmission planning assessments.[48] This study revealed a potential need to develop additional cases, such as to study heavy transfers in both directions of an interface.

Observation 4: Future studies should include stability analysis.
Part 1 studies included power flow analysis, voltage screening, and known stability limits. Future studies should include more expansive stability analysis to identify potentially more restrictive limits, especially because stability limitations can become more prominent when there is increased reliance on heavy transfers across large areas.

Observation 5: A future study evaluation schedule is needed.
The study results are highly dependent on the point-in-time information used to develop the cases. Since generation construction and retirement, transmission expansion plans, and load forecasts are constantly evolving, it would be beneficial to repeat this transfer analysis on a regular basis. Further, given the long lead time required for transmission additions, consideration should be given to future study horizons.[49]

[48] For example, TPL-001-5 (nerc.com)
[49] The study horizon for ITCS Part 2 is 2024 and 2033.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-26-46
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	)))))	Order No. 202-26-47

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 68
Grid Strategies September Report

A Review of DOE's Second 202(c) Order for the Campbell Coal Plant

Michael Goggin

September 2025

This report responds to DOE's August 2025 order[1] mandating that the Campbell coal plant in Michigan be kept online, overriding decisions to retire the plant by the utility, Michigan utility regulators, and the regional grid operator. Our June report, *A Review of DOE's 202(c) Order for the Campbell Coal Plant,* responded to DOE's first order[2] for the Campbell plant, which was issued in May. This report reaffirms and incorporates the June report. As explained there, utility, state, regional, and national regulatory requirements already ensure Michigan and MISO have enough power plant capacity to keep the lights on. This report focuses on rebutting new arguments in DOE's August 2025 order.

1. There is no evidence MISO needs Campbell this fall.

DOE's May order for Campbell argues that "NERC anticipates that the near-term period of highest capacity shortfall for MISO will occur in August,"[3] and repeatedly claims that summer was the primary risk period. DOE's new order now proposes to keep the plant online for 90 more days, through almost the entire fall season.

To support this new order, DOE cites, among other sources, to a theoretical modeling report MISO published in 2023, the *Attributes Roadmap*. That report actually found minimal fall risk under both MISO's current generation mix and expected 2032 generation mix, and only identified potential fall risk under another theoretical future generation mix, for 2027.[4] The potential future generation mix that generates equivalent fall and summer risk includes 22 GW of coal capacity, 49 GW of wind, and 44 GW of solar.[5] As of June 2025, MISO has around 47 GW of coal capacity, 32 GW of wind, and 18 GW of solar, close to the current generation mix that

[1] U.S. Dep't of Energy ("DOE"), *Order No. 202-25-7* (Aug. 2025), *available at* https://www.energy.gov/sites/default/files/2025-08/MISO%20Order%20No.%20202-25-7.pdf (*hereinafter* "*Order No. 202-25-7*").
[2] DOE, *Order No. 202-25-3* (May 2025), *available at* https://www.energy.gov/sites/default/files/2025-05/Midcontinent%20Independent%20System%20Operator%20%28MISO%29%20202%28c%29%20Order_1.pdf (*hereinafter* "*Order No. 202-25-3*").
[3] *Id.* at 1.
[4] Midcontinent Indep. Sys. Operator, Inc. ("MISO"), *Attributes Roadmap: A Reliability Imperative Report* (Dec. 2023), at 11, *available at* https://cdn.misoenergy.org/2023%20Attributes%20Roadmap631174.pdf.
[5] MISO, *MISO Futures Report: Series 1A* (Nov. 1, 2023), at 75, *available at* https://cdn.misoenergy.org/Series1A_Futures_Report630735.pdf.

MISO's report found did not have fall risk.[6] Thus, the MISO report cited by DOE actually confirms there is minimal fall risk associated with today's generation mix.

Contrary to DOE's unsupported claim of fall resource adequacy risk, MISO's data show it has surplus generating capacity this fall. MISO uses detailed probabilistic resource adequacy modeling, described in more detail in my June report, to confirm that it has sufficient resources to meet electricity demand in all seasons. The June report explains that MISO uses the industry standard criteria of a 1-day-in-10-year Loss of Load Expectation ("LOLE") to determine the optimal amount of capacity needed to meet demand without burdening ratepayers with the cost of surplus capacity. MISO explains that it ensures that:

> [T]he annual LOLE is at 1 day in 10 years, or 0.1 LOLE for the Summer season, and for the off seasons, values of LOLH [Loss of Load Hours] and EUE [Expected Unserved Energy] are calculated at the point where the seasonal LOLE is at 1 day in 100 years, or 0.01 LOLE.[7]

In other words, for this fall, MISO targeted a reserve margin that meets a level of reliability that is 10 times more stringent than the industry standard.

Moreover, MISO's capacity auction for this fall produced a large capacity surplus above even the level needed for the unduly stringent 1-day-in-100 years target. Without Campbell, MISO's capacity auction for this fall cleared at a reserve margin of 17.5%, well above the 14.9% target needed to meet the 1-day-in-100-years target.[8] Retaining Campbell only further adds to that capacity surplus, burdening MISO ratepayers with the cost of retaining capacity that is not needed.

The zonal results from MISO's 2025/26 capacity auction also confirm there is no resource adequacy shortfall this fall in Zone 7, which is the MISO footprint in Michigan's Lower Peninsula. Without Campbell, Zone 7 has 337.5 MW of supplies above the Local Clearing Requirement, which is the amount of capacity that MISO has concluded must come from within Zone 7 after accounting for transmission constraints.[9] And MISO also studied Campbell's retirement and determined that it could retire without causing a reliability concern on the local (sub-Zone 7) transmission system. If MISO had identified an unmet reliability need, it could have retained Campbell under a System Support Resource designation.

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[6] MISO, *Fact Sheet* (July 2025) (last visited Sept. 4, 2025), https://www misoenergy.org/meet-miso/media-center/corporate-fact-sheet/.
[7] MISO, *Planning Year 2025-2026 Loss of Load Expectation Study Report* (2025), at 9, *available at* https://cdn.misoenergy.org/PY%202025-2026%20LOLE%20Study%20Report685316.pdf?v=20250313114401 (*hereinafter* "PY 2025−2026 LOLE Study Report").
[8] MISO, *Planning Resource Auction: Results for Planning Year 2025-26 (Corrections)* (May 29, 2025), at 4−5, https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250529_Corrections694160.pdf.
[9] *Id.* at 19.

2. There is no evidence Campbell was needed during this year's summer heat wave.

DOE claims that there are "[c]ontinuing [e]mergency [c]onditions" and that Campbell will "continue to be a critical asset to maintain reliability in MISO this summer" because MISO issued one Max Generation Warning on July 29, Max Generation Alerts on July 28 and 29, and reached a Maximum Generation Event Step 1b on June 23.[10] All of these events are operating practices well within MISO's established processes for periods of high electricity demand, and do not indicate that Campbell was actually needed to maintain reliability. In fact, Step 1b is part of Event Step 1, which is only the first step out of five in MISO's toolkit for addressing maximum generation events,[11] as shown below. The July Max Generation Alerts and Warning that DOE highlights did not even reach that first step in MISO's event hierarchy.

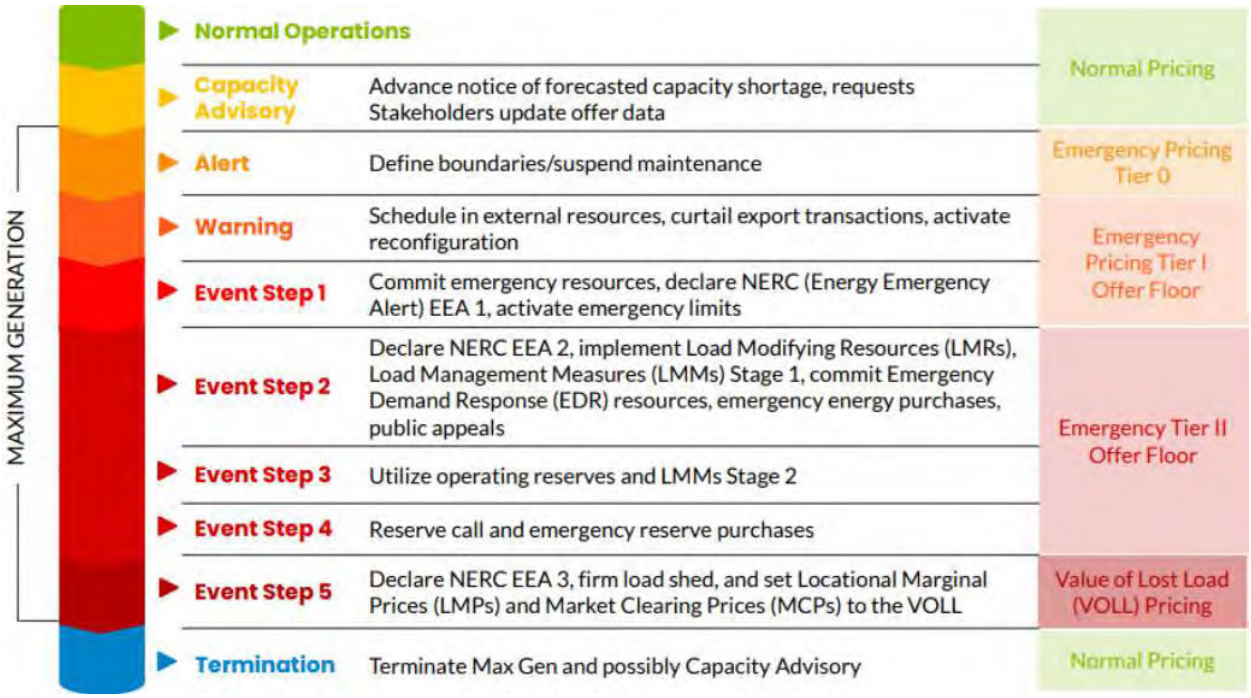


Figure 1: MISO chart showing its steps for Maximum Generation Events

Our June report documented these and other tools MISO has available and uses when electricity demand is high. As the June report explained, the additional tools MISO can deploy if an event progresses past Step 1b include "activating additional tiers of demand response resources, issuing public conservation requests, procuring emergency energy, and directing resources with environmental de-rates to request waivers, all before load is shed."[12] As additional indication that

[10] *Order No. 202-25-7*, *supra* note 1, at 2–3.
[11] MISO, *Maximum Generation Emergency Declarations through June 2024* (updated Aug. 30, 2024), at 2, *available at* https://www.oasis.oati.com/woa/docs/MISO/MISOdocs/Capacity_Emergency_Historical_Information.pdf (*hereinafter* "MISO Capacity Emergency Historical Information").
[12] *Motion to Intervene and Request for Rehearing and Stay of Public Interest Organizations: Exhibit 2, Grid Strategies Report* (June 18, 2025), at 38–39.

1b events are routine, MISO North/Central experienced one 2a event, one step beyond 1b, in each of 2021, 2022, and 2023.

MISO North/Central experienced seven Maximum Generation warnings or full events from 2020 through June 2024: three during the summer, three during the winter, and one during the spring.[13] None were in the fall, confirming that fall is not a period of significant loss of load risk for MISO. And none of those warnings or events resulted in a loss of load in MISO North/Central.[14]

Federal government data show that the Campbell plant had poor availability this summer, including during these seven MISO peak demand events in 2020−2024, and the June 2025 Step 1b event that DOE's order highlights.[15] In the majority of those events, at least one of the three generating units at Campbell was offline, as shown in Table 1 below. On average, only two of three Campbell units were available during these seven events, reducing the plant's output during the events by 30% on average. For comparison, on average MISO coal plants have an outage rate of less than 8% for smaller units and less than 10% for larger units.[16]

Table 1: Campbell Availability During Recent MISO North/Central Maximum Generation Events

Event	Units offline	Maximum output (MW)	Plant availability
July 6-7, 2020, 1a	2	334	22%
Feb 16, 2021, 1b	0	1,426	94%
June 10, 2021, 2a	0	1,514	100%
Jan 7, 2022, warning	2	902	60%
May 12-13, 2022, warning	0	1,434	95%
Dec 23, 2022, 2a	1	1,203	79%
Aug 23-24, 2023, 2a	1	898	59%
June 23, 2025, 1b	2	760	50%
Average	**1**	**1,059**	**70%**

[13] MISO Capacity Emergency Historical Information, *supra* note 11, at 2 (details on MISO's designation of warning, 1a, 1b, and 2a events).
[14] MISO did shed 700 MW of firm load in MISO South during Winter Storm Uri, but none in MISO North/Central. *See* Fed. Energy Regulatory Comm'n ("FERC"), et al., *The February 2021 Cold Weather Outages in Texas and the South Central United States* (last updated Dec. 8, 2021), at 151, *available at* https://ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and.
[15] U.S. Environmental Protection Agency ("EPA"), *Continuous Emission Monitoring Systems (CEMS) Data* (last visited Sept. 4, 2025), https://campd.epa.gov/data/custom-data-download. Data for Campbell plant output during the July 2025 MISO max gen warning event are not yet available. EPA Continuous Emission Monitoring Systems data report gross generation before subtracting plant consumption and losses, so all figures here are gross generation. The "maximum output" column reports the maximum gross generation of the plant during the event, and the "plant availability" column reports this maximum output as a percent of the maximum gross generation of 1,514 MW during the event on June 10, 2021.
[16] PY 2025−2026 LOLE Study Report, *supra* note 7, at 26.

During the peak demand period of the June 23, 2025, Step 1b event that DOE's order highlights, Campbell Units 1 and 2 provided zero output. As shown in Figure 2 below, Unit 2 had been offline for more than a month at that point, while Unit 1's output abruptly dropped to zero midday on June 23, before peak demand that evening.

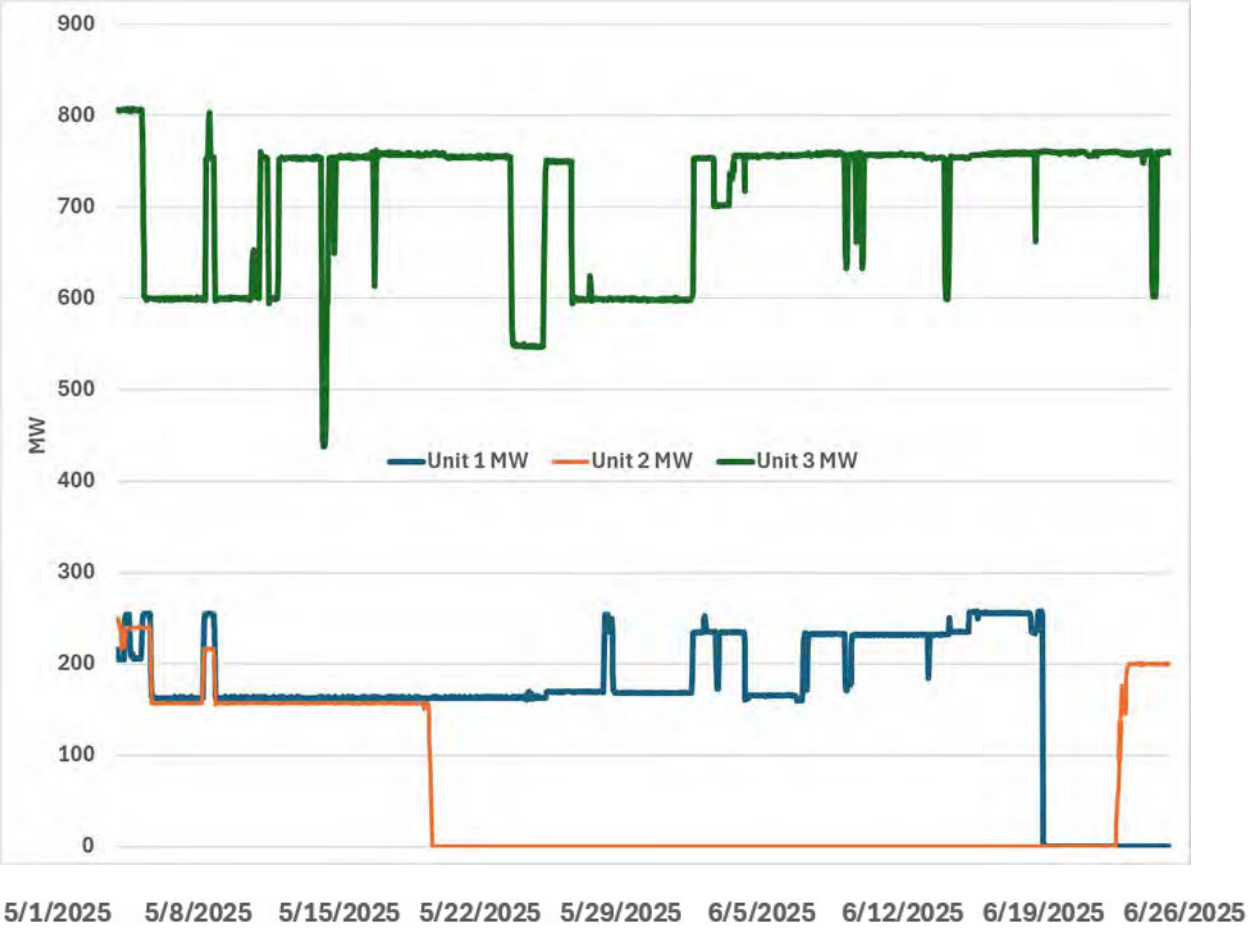


Figure 2: Campbell unit output over May and June 2025, from EPA CEMS dataset

3. Campbell's high costs make it uneconomic even during high demand periods

Public data indicate that Campbell's fuel and operating and maintenance costs exceed $40/MWh, which makes it an uneconomic source of generation. Specifically, DOE's Energy Information Administration ("EIA") data show Campbell paid an average of $3.36 per million British thermal units ("MMBtu") for coal purchased in June 2025, representing a more than 25% cost increase from the previous month; this translates into a cost of $34.15/MWh based on Campbell's fuel consumption and electricity generation in June.[17] Data filed with the Federal Energy Regulatory Commission ("FERC") show that Campbell incurred over $54 million in non-fuel operations and

[17] Energy Info. Admin. ("EIA"), *Form EIA-923 detailed data with previous form data* (Aug. 2025, last visited Sept. 4, 2025), (data for June 2025), https://www.eia.gov/electricity/data/eia923/xls/f923_2025.zip.

maintenance ("O&M") costs in 2024,[18] which corresponds to an additional $6.59/MWh in average cost per MWh generated in 2024, for total operating costs of $40.74/MWh.[19]

These costs are higher than average prices in the MISO market during a typical year, and even during high demand periods like MISO experienced in June 2025. Over the one-year period from July 2024 through June 2025, the MISO Day-Ahead price at the Campbell market node exceeded $40.74/MWh in only 21% of hours.[20] Thus, in 79% of hours, Campbell could not earn enough to cover its operational costs.

Campbell's operating costs exceeded the market price at the Campbell node over 70% of the time from May 24−June 30, 2025;[21] during those hours, the plant clearly operated at a loss. Combining this MISO price data with the Campbell hourly generation data presented above confirms that the plant operated at a net loss in the MISO market over those 38 days, with losses from the plant operating during periods of low prices more than offsetting profits during higher-priced hours. This indicates that the plant operated at an overall loss even during a high-demand summer period that included the June 23 event, which is consistent with Consumers Energy reporting that it incurred net costs of $29 million over that time period due to DOE's Campbell order.[22]

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[18] *Consumers Energy Company submits FERC Form 1 report for 2024/Q4*, Docket No. EL25-90 (Mar. 20, 2025), Accession No. 20250320-8006, at 402, *available at* https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20250320-8006. Fuel costs in row 20 were subtracted from total production expenses in row 34 to arrive at non-fuel O&M costs. The non-fuel O&M costs for Unit 3 were then divided by .9331 to calculate the total non-fuel O&M costs for Unit 3, reflecting that the cost figures in Form 1 only report Consumers Energy's costs for its 93.31% share of Unit 3.

[19] Form 1 does not distinguish between variable O&M costs that are incurred as a function of generating MWh and fixed O&M costs that are incurred simply by keeping the plant open. However, given that both types of costs will be incurred as a result of DOE mandating that the Campbell plant remain open, and the plant's ongoing capacity factor is unlikely to drastically change from its capacity factor in 2024, expressing O&M costs in $/MWh accurately reflects the ongoing costs of operating the plant. Dollar-per-MWh costs were calculated based on EIA Form 923 generation for 2024.

[20] MISO, *Historical Annual Day-Ahead LMPs* (July 3, 2025) (last visited Sept. 4, 2025), https://www misoenergy.org/markets-and-operations/real-time--market-data/market-reports/#nt=%2FMarketReportType%3AHistorical%20LMP%2FMarketReportName%3AHistorical%20Annual%20Day-Ahead%20LMPs%20(zip)&t=10&p=0&s=MarketReportPublished&sd=desc. Coal plants typically sell their output in the Day-Ahead market instead of the Real-Time market due to their inflexibility, so this analysis is based on Day-Ahead market prices.

[21] This period was chosen because DOE issued the 202c order late on May 23, and EPA data showing the hourly generation of Campbell is currently only available through the end of June 2025.

[22] U.S. Sec. and Exch. Comm'n ("SEC"), *Form 10-Q* (July 31, 2025), (report for Consumers Energy for the second quarter of 2025, filed July 2025), *available at* https://d18rn0p25nwr6d.cloudfront net/CIK-0000201533/10a900b7-263b-4ccd-82a0-4162ba7ae5f2.pdf.

4. DOE's July 2025 Resource Adequacy report is based on flawed inputs

DOE's order briefly mentions a report it issued on July 7, 2025,[23] entitled *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid*. That report has been widely criticized,[24] including for vastly overstating the need for resources by using assumptions for nationwide generator retirements, capacity additions, and load growth that are drastically higher than other data and projections from EIA, the DOE entity tasked with "independent statistics and analysis." As summarized in Table 2 below, in total DOE's report overstates the need for resources by around 200 GW relative to other DOE sources. If those inputs were used instead, the report would not even have found a 2030 need because 109 GW of resource additions would more than meet the 92 GW of need created by 40 GW of load growth plus 52 GW of retirements.

Table 2: Assumptions in DOE's July 2025 report vs other DOE data, GW by 2030

	DOE July 2025 report	Other DOE data/projections	Overstatement of need for resources
Capacity retirements	104 GW firm	52 GW nameplate[25]	52 GW
Resource additions	22 GW firm	109 GW[26]	87 GW
Load growth	101 GW	40 GW in high growth case[27]	61 GW
Total overstatement of need for resources			**200 GW**

5. Conclusion

This report builds on the points made in our June report. DOE's two Campbell orders are both unnecessary and costly market interventions.

6. Qualifications of Michael Goggin

Michael Goggin has worked on electricity market and reliability issues for over 20 years. At Grid Strategies he serves as an expert on those topics for a range of clients including state utility

[23] DOE, *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid*, (July 7, 2025), at 1, *available at* https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf.

[24] For example, *see* Ric O'Connell, *GridLab Analysis: Department of Energy Resource Adequacy Report* (July 11, 2025), *available at* https://gridlab.org/gridlab-analysis-department-of-energy-resource-adequacy-report/; *see also* Jennifer Danis, et al., *Enough Energy: A Review of DOE's Resource Adequacy Methodology* (July 2025), *available at* https://policyintegrity.org/files/publications/IPI_EnoughEnergy_FinalReport.pdf.

[25] EIA, *EIA-860M* (June 2025), (data for May 2025), https://www.eia.gov/electricity/data/eia860m/.

[26] *Id.* To be conservative, the tally of 109 GW of planned resource additions includes only thermal and battery resources and does not account for the significant resource adequacy contributions from planned wind and solar resources. The 22 GW figure for the July 2025 DOE report is based on the statement on page 1 that for capacity additions by 2030, "only 22 GW would come from firm baseload generation sources."

[27] EIA Annual Energy Outlook high growth case assumes 6% growth through 2030, versus 15% assumed in DOE's July 2025 report.

regulators, grid operators, and non-profit organizations. He has testified as an expert in dozens of proceedings before state utility commissions in Arizona, Colorado, Georgia, Iowa, Illinois, Indiana, Wisconsin, Louisiana, Michigan, Minnesota, Missouri, Montana, Nevada, New Mexico, North Carolina, Ohio, Oklahoma, South Carolina, Virginia, Washington, and Wisconsin, as well as before FERC.

For the preceding ten years Michael worked at the American Wind Energy Association (now known as the American Clean Power Association), where he provided technical analysis regarding renewable energy, transmission, and wholesale electricity markets, including directing the organization's research and analysis team from 2014-2018. Prior to the American Wind Energy Association, he worked at a firm serving as a consultant to DOE, and at two environmental groups.

7. Sources

The principal documents I relied on in preparing this report include the materials listed below and in footnotes. To the extent feasible, relevant documents are included in the Appendix of the Request for Rehearing.

-DOE, *Order No. 202-25-7* (Aug. 2025), *available at* https://www.energy.gov/sites/default/files/2025-08/MISO%20Order%20No.%20202-25-7.pdf

-DOE, *Order No. 202-25-3* (May 2025), *available at* https://www.energy.gov/sites/default/files/2025-05/Midcontinent%20Independent%20System%20Operator%20%28MISO%29%20202%28c%29%20Order_1.pdf

-MISO, *Planning Year 2025-2026 Loss of Load Expectation Study Report*, *available at* https://cdn.misoenergy.org/PY%202025-2026%20LOLE%20Study%20Report685316.pdf?v=20250313114401

-MISO, *Planning Resource Auction Results for Planning Year 2025-26 (Corrections, reposted May 29, 2025)*, *available at* https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250529_Corrections694160.pdf

-MISO, *Attributes Roadmap* (Dec. 2023), *available at* https://cdn.misoenergy.org/2023%20Attributes%20Roadmap631174.pdf

-MISO, *MISO Market Capacity Emergency*, *available at* https://cdn.misoenergy.org/SO-P-EOP-11-002%20Rev%2021%20MISO%20Market%20Capacity%20Emergency683501.pdf

MISO, *Historical Annual Day-Ahead LMPs*, *available at* https://www.misoenergy.org/markets-and-operations/real-time--market-data/market-reports/#nt=%2FMarketReportType%3AHistorical%20LMP%2FMarketReportName%3AHistori

cal%20Annual%20Day-Ahead%20LMPs%20(zip)&t=10&p=0&s=MarketReportPublished&sd=desc

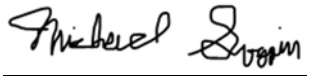
-FERC, *Consumers Energy Company submits FERC Form 1 report for 2024/Q4* (Mar. 2025), *available at* https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20250320-8006

-U.S. EPA, *Continuous Emission Monitoring Systems: Custom Data Download*, *available at* https://campd.epa.gov/data/custom-data-download

-U.S. DOE, *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid* (July 2025), *available at* https://www.energy.gov/sites/default/files/202507/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf

-DOE Energy Information Administration, *Form EIA-923 June 2025* (Aug. 2025), *available at* https://www.eia.gov/electricity/data/eia923/

-DOE Energy Information Administration, *Form EIA-860M*, (data for May 2025, published June 2025), *available at* https://www.eia.gov/electricity/data/eia860m/



Michael Goggin
Vice President
Grid Strategies, L.L.C.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-26-46
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	)))))	Order No. 202-26-47

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 69
IN Haze SIP Responses to Public Comments

Appendix V

RH SIP Responses to Public Comments

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RESPONSES TO PUBLIC COMMENTS ON INDIANA'S REGIONAL HAZE STATE IMPLEMENTATION PLAN

United States Environmental Protection Agency (email from Pamela Blakely received on November 15, 2021)

Comment 1
The State should also include the summarized FLM comments and responses in the SIP narrative rather than just an appendix in accordance with 40 CFR51.308(i)(3)

Response 1
The Federal Land Manager's comments are summarized in Appendix U to allow for a more concise document. Since the Appendix is a part of the SIP, IDEM would prefer not to incorporate all of the same language in the body of the document.

Comment 2
As a general matter, EPA expects states to select their largest in-state contributors to visibility impairment for four-factor analysis. See July 8, 2021, Clarification Memo at 4. In Indiana's case, many of these largest contributors appear to be EGUs that have been screened in through the Q/d analysis. In some instances, IDEM may find it appropriate to not select such a source, even if it is one of the largest sources in the state. For instance, IDEM may decline to not select a particular source based on a demonstration that the source is operating existing effective controls. See August 2019 Guidance 22-25: July 8, 2021, Clarification Memo 5.

Comment 3
IDEM suggests that recent emission reductions owing to other control measures are a basis for not conducting a four-factor analysis for the selected EGUs. However, it is generally inappropriate to not select a source simply because it was part of an emissions sector that is the subject of numerous industry-wide EGU control programs and downward emissions trends for the first planning period. As a general matter, once a source is screened in based on visibility impacts, a state should not forgo four-factor analysis merely because of other emission reductions (at the source or other sources) or because of recent improvements in visibility. Therefore, IDEM should explain in greater detail how not selecting EGUs for a four-factor analysis still ensures reasonable progress towards natural visibility. If the various control measures and shutdowns listed in this section are necessary for reasonable progress and therefore part of IDEM's Long-Term Strategy, those must be federally enforceable and in the SIP.

Responses 2 and 3
Indiana received numerous comments related to the state's decision to evaluate all of the electric generating unit (EGU) sources that met Indiana's criteria for selecting sources for four-factor analysis using a reasonable progress analysis for the EGUs. This decision was made early in the State Implementation Plan (SIP) development process based on the EPA's "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period" document, dated August 20, 2019 (2019 EPA Guidance). According to the 2019 EPA Guidance, a key flexibility of the regional haze program is that a state is not required to evaluate all sources of emissions in each implementation period; an analysis of control measures is not required for every source in each implementation period; and for the sources that are not selected for an analysis of control measures for purposes of the second implementation period, it may be appropriate for a state to consider whether measures for such sources are necessary to make reasonable progress in later implementation periods.

Indiana chose to wait until the third planning period to require four-factor analyses from its EGU sources due to the fact that the landscape for the EGU sector has changed so dramatically since the last planning period, resulting in large emission reductions. The EGU sector continues to change rapidly, with a number of additional shut-downs being announced just within the past year. The implementation of new control programs designed to target nitrogen oxides (NO_x) and sulfur dioxide (SO_2) emissions from the EGU sector have resulted in various upgrades to existing emissions control equipment, several installations of new add-on control devices, a number of conversions to natural gas and numerous EGU retirements with more scheduled shutdowns to come over the second implementation period. In addition, fuel costs have upended the order in which resources are dispatched by the Midcontinent Independent System Operator (MISO) to meet the region's power generation needs and maintain adequate power grid management in the future. Coal fired units that were previously dispatched first are now dispatched last. This change in economic driven dispatching is expected to result in less reliance on the remaining coal fired EGUs and accelerated retirement. As such, Indiana believes that conducting four-factor analyses for EGUs during the next planning period would result in a better use of resources because much of what the state would require based on four-factor analyses conducted for the EGUs would become moot as the EGU sector remains in flux as sources continue to shutdown units, convert to natural gas, and rely more on renewable energy. In fact, allowing the EGU sector to stabilize over the course of the next implementation period would provide more definitive information for better decision-making during the third planning period and produce more feasible and meaningful analyses. Especially in light of the fact that a detailed reliability study would need to be conducted in order to understand the impact that additional shutdowns of coal fired units would have on delivering electricity reliably, dependably, and cost-effectively to the grid.

The RH Rule is purposefully intended to give states discretion and flexibility in meeting their statutory and regulatory requirements to reduce visibility impairment at Class I areas as directed through the RH program. The rule allows states to determine how to show reasonable progress and permits states to leverage emission reductions achieved through other CAA programs that will further improve visibility in protected areas. While the EGU source category was not chosen by IDEM to have four-factor analyses conducted for the second implementation period, these sources were not exempt from being evaluated. A reasonable progress analysis for these units was conducted in lieu of four-factor analyses. Indiana's reasonable progress analysis for these units consists of a quantitative analysis of statewide NO_x and SO_2 emission reductions from Indiana's EGU fleet for 2007-2019; photochemical modeling using 2016 NO_x and SO_2 base-year modeled emissions for all existing Indiana EGUs in 2016 to projected 2028 emissions; and source apportionment modeling to assess visibility impacts of all EGUs in Indiana.

EPA addresses visibility requirements in the preamble of the RH Rule as shown on page 35726 (Federal Register Vol 64, No. 126, Pg. 35726): "Since the national goal is expressed in terms of air quality (i.e., visibility) rather than emissions, we (EPA) believe that it is very important to require the quantitative tracking of visibility impairment as an integral element in measuring reasonable progress." Also, on page 35727, "Tracking "reasonable progress" should involve the tracking of both emissions and visibility improvement". IDEM has demonstrated the decrease of both emissions and visibility impairment by showing significant visibility improvement at Class I areas; and expects the emissions analyses, review of emission controls, current and expected retirements for coal-fired boilers with more renewable energy being utilized for future power generation, and modeled visibility impacts to adequately address Indiana's overall visibility impacts. Both factors (emissions and visibility impairment) are more than adequately addressed in Indiana's EGU reasonable progress analysis with future emission reductions anticipated.

Furthermore, the EGU sector has contributed its fair share of the visibility progress made over the last implementation period which has resulted in emission reductions below the glidepath in all of the Class I areas for which Indiana sources have been found to impact visibility. IDEM has determined existing emission controls are adequate to address regional haze for EGU sources throughout the state based on current "on-the-books" regulatory measures, such as the Cross State Air Pollution Rule (CSAPR) and the Mercury and Air Toxics Standards for the second implementation period. In addition, Indiana will continue to make progress towards the national goal of natural visibility by 2064 with the implementation of other CAA regulations, such as the Revised CSAPR Update Rule and new wastewater regulations for coal ash. The Revised CSAPR Update Rule reduces the 2021 NO_x Ozone Season budget for Indiana from 13,313 to 9,754 tons of NO_x by 2024 forcing optimization of existing controls; and more stringent federal wastewater guidelines have become more of a contributing factor in causing EGUs to move away from coal or shut down. The new wastewater regulations require power plants to clean coal ash and toxic heavy metals such as mercury, arsenic, and selenium from plant wastewater before it is dumped into streams and rivers. Additional emission control measures and potential future reductions will continue to be appropriately evaluated in upcoming implementation periods.

Comment 4
Please indicate which, if any, of the retirements are federally enforceable and planned for inclusion in the long-term strategy (LTS) and SIP. Please describe the regulatory mechanisms IDEM uses to ensure retirements and shutdowns are federally enforceable and permanent.

Comment 5
For these planned retirements, if IDEM chose to perform four-factor analyses on EGUs, IDEM could fully support its assertion that new emission control equipment is not cost-effective, if that is ultimately the case. A cost-effectiveness analysis within a four-factor analysis would provide actual data to support (or refute) this claim. If the State is relying on anticipated source shutdowns as part of its long-term strategy for making reasonable progress, IDEM must make these planned retirements enforceable in the SIP. This includes reliance on shutdowns both to forgo a four-factor analysis and to shorten the remaining useful life of a source in conducting a four-factor analysis. See EPA Clarifications Memo at 10; see also Guidance at 20 and 34. If IDEM does not include these retirements in its SIP, then the State should consider a four-factor analysis for these sources.

Without the four-factor analyses, the reference to "cost-effective method" on page 57 of the draft noted above offers no support for the argument that "additional emissions reductions through the use of new emission control equipment or emissions limitations is not desired". Further, decreasing emissions trends do not free the state from an obligation to meet the CAA and Regional Haze Rule requirements to consider what is necessary for reasonable progress, which may in fact be "new emission control equipment or emissions limitations."

Comment 7
There are various instances throughout the four-factor analyses where IDEM concludes that X (one of the sources) has "no reasonable set of NO_x emission control measures beyond what is currently installed and operated for these emission units" or "[X] already utilizes [Y] as an existing NO_x emission control measure." However, IDEM should take its analysis one step further and indicate whether those conclusions mean that they are determining that existing measures are necessary for reasonable progress. As a general matter, EPA believes that existing measures are necessary for reasonable progress and therefore must be incorporated into the regulatory portion of the SIP. However, the state may make a weight-of-evidence

demonstration that a particular existing measure is not necessary for reasonable progress. See July 8, 2021, Clarification Memo 8-10.

Comment 9
Is there an enforceable prohibition on coal burning at the source or is it now physically impossible to use coal as a fuel source in the future?

Responses 4, 5, 7, and 9
Indiana received numerous comments related to including permanent and enforceable emission limits for existing and new emission controls that are necessary to make reasonable progress in the SIP as part of the state's long-term strategy. IDEM doesn't agree that the state should require stricter enforceable limits through secondary (welfare) control programs than those required to address health-based primary standards unless needed to show visibility improvements. The implementation of health-based primary air quality standards, such as the 2008 1-hour SO_2, the 2012 fine particulate matter standard and the 2015 ozone standard have forced sources to meet new air quality targets that require them to maintain stricter control of NO_x and SO_2 emissions. Whether through source-specific limits that are permanent and federally enforceable, or though federally enforceable programs to address interstate transport, these emission reductions have contributed to the significant progress made over the course of the first implementation period.

It should be noted that to incorporate new emission limits into Indiana's SIP, a new rule must be developed and adopted. The state's rulemaking process takes three to four years to complete, including federal SIP approval. This process would be very resource intensive for what would amount to small visibility benefits for the non-EGUs and a limited amount of time before the units are no longer operated for the EGUs.

Indiana also received a number of comments concerning the weight of evidence demonstration for existing controls. The EPA and other commenters contend that if IDEM concludes that the existing controls at a selected source are necessary to make reasonable progress, a weight-of-evidence demonstration must be conducted to establish emission limits for the existing controls. As previously mentioned, the cost and use of resources and time required to evaluate selected sources for permanence of existing controls and emission limits compared to the visibility benefits realized to address transported NO_x and SO_2 emissions at this time is not warranted.

The RH Rule was designed to be implemented with respect to reasonable visibility progress to natural conditions by the year 2064 with several implementation periods to measure and assess reasonable progress towards the natural visibility conditions. The uniform rate of progress (URP) for each Class I area, especially in the eastern half of the country, shows the visibility progress made during the last implementation period represents another positive step towards attaining natural conditions at all Class I areas by 2064, if not much sooner. A comparison of visibility impairment values over time is an appropriate measure to determine if improvements or progress is made for Class I area visibility. The URP is adjusted to account for several different factors that make up visibility impairment. The fact that the most current monitored and modeled visibility values are below the uniform path to natural visibility conditions for eastern U.S. Class I areas must be considered in establishing Indiana's long-term strategy for the RH SIP second implementation period. Furthermore, the fact that monitored visibility data from the IMPROVE monitoring network has shown progress from 2000 to 2018 is considerable, indicating states have been responsive to reducing emissions through state and federal regulatory measures and as a result, visibility impairment is trending downward. Current 2018 monitored visibility data nearly match the projected modeled visibility values for 2028 at most

Class I areas throughout the eastern U.S. This clearly shows tremendous progress, ranging up to 10 years ahead of what is projected through visibility modeling. These visibility benefits are expected to continue with anticipated future reductions in emissions.

Some commenters provided additional information on individual EGUs and/or information that could be used in a four-factor review that IDEM cannot agree or disagree with because no four-factor review for EGUs was conducted. Many controls are already in place for EGUs, and the RH SIP includes the level of efficiency obtained by each control (as shown in Appendix F of the RH SIP). Regional Haze does not require a specific level of control and many of the control efficiencies of controls on Indiana sources are considered at a high level of control.

Indiana has determined existing emission controls are adequate to address regional haze for sources throughout the state based on the tremendous visibility progress made to date along with current "on-the-books" regulatory measures. Both factors (emissions and visibility impairment) are addressed in Indiana's RH SIP with future emission reductions anticipated. These reductions will be appropriately evaluated in upcoming implementation periods as the natural visibility goals are realized by 2064.

Comment 6
IDEM should specifically address whether the cost-effectiveness of the $1679/ton control option for SNCR is reasonable and make a specific finding as to the Greencastle facility regarding whether new controls will be required for reasonable progress.

Comment 8
As with the other four-factor analyses, IDEM does not appear to make specific findings for each facility of whether the cost effectiveness of the controls evaluated is reasonable. Somewhere in the SIP document, such as Section 26.0 Decision on What Control Measures are Necessary to Make Reasonable Progress, IDEM should make specific findings for each facility regarding whether the cost effectiveness for a new control option within a certain range is reasonable and if it will be required for reasonable progress. As to the cost effectiveness of controls for the Burns Harbor emission units of $4,000/ton SO_2, IDEM would be expected to address the reasonableness of options in this range.

Comment 10
IDEM should specifically address cost-effectiveness estimates in this range and make a specific finding for the facility regarding whether these costs are reasonable and if they will be required for reasonable progress.

Comment 11
If IDEM determines that no additional (i.e., new) measures are necessary to make reasonable progress for a particular source, the State must then determine whether the source's existing measures are necessary to make reasonable progress. See section 4 (pages 8-12) of the Clarifications Memo for information on determining when a source's existing measures are necessary to make reasonable progress. Generally, a source's existing measures are needed to prevent future emission increases and are thus needed to make reasonable progress. If IDEM concludes that the existing controls at a selected source are necessary to make reasonable progress, IDEM must adopt emissions limits based on those controls as part of its long-term strategy for the second planning period and include those limits in its SIP (to the extent they do not already exist in the SIP).

Comment 12
Section 26.1 contains IDEM's conclusions regarding the State's decision not to require additional control measures. This is the heart of IDEM's main finding, although it doesn't appear until page 225. Therefore, it would be helpful if IDEM would provide conclusions specific to the selected sources indicating what, if any, additional control measures are determined to be necessary for reasonable progress. If no additional control measures are selected by Indiana, IDEM should further explain (1) if that determination means that existing measures are necessary for reasonable progress, and (2) how a determination of no additional control measures nonetheless ensures reasonable progress is made.

Responses 6, 8, 10, 11, and 12
Indiana received numerous comments regarding the state's decision not to require additional controls for some of the sources selected for four-factor analysis based on the cost effectiveness result for specific units. IDEM used the Q/d analyses to quantify and consider the visibility impacts of sources at Class I areas for the purpose of selecting sources to analyze for four-factor analysis. The four-factor analysis is used to evaluate potential controls for specific pollutants emitted from individual emission units at a source to determine what controls are cost effective for reducing that pollutant. The RH Rule requires states with Class I areas to consider these factors in establishing their reasonable progress goals for reducing the impact of emissions from sources within and outside the state on visibility impairment at each Class I area within the state. However, the use of the four-factor analysis and by extension the cost effectiveness evaluation for states that do not have Class I areas for the purpose of establishing a long-term strategy is not clearly defined.

IDEM did not make a determination on whether a specific dollars/ton cost for the affected sources is cost effective because subsequent source apportionment modeling results showed that these sources would not have a measurable impact on improving visibility at Class I areas. In other words, a low-cost effectiveness value at the unit level for sources with modeled insignificant visibility impacts to Class I areas outside the state does not necessarily mean reductions will provide a measurable visibility benefit. Although the cost effectiveness evaluation of the four-factor analysis for some sources shows a low-cost value to install some new control measures, the source apportionment modeling for their associated source sectors does not show that there will be appreciable differences in visibility benefits. This lack of appreciable difference in visibility benefits is due to the significant visibility progress realized so far based on emission reductions and the distance to a Class I area and/or the amount of emissions from the four-factor source. Moreover, the variables used in the cost estimates and cost effectiveness calculations vary depending on a variety of different circumstances and are not consistent across sources. The cost and use of resources and time required to evaluate selected sources for unit-specific emission control measures compared to the visibility benefits realized to address transported NO_x and SO_2 emissions at this time is not warranted. So, when evaluating the selected sources for additional controls, both monitored and modeled visibility benefits were strongly considered.

IDEM received numerous comments on the methods and accuracy of the four-factor analyses included in the draft SIP. IDEM appreciates the thoroughness and amount of detail that went into the review of the draft SIP. IDEM used acceptable methods to estimate costs with input and review from the subject sources. Therefore, IDEM is not updating the cost effectiveness numbers for the final SIP, unless instances of errata. Different decisions on assumptions made could change the cost per ton estimates but not in an appreciable way to change the outcome of reducing emissions enough to have a measurable impact on visibility values. Please see the four-factor analyses in Section 10, the cost estimates and cost effectiveness evaluations in

Appendices H and J, and the responses from affected sources to the Federal Land Managers comments in Appendices P-T for further detail on assumptions used in the analyses.

Indiana has determined existing emission controls are adequate to address regional haze for sources selected for four-factor analysis based on the tremendous visibility progress made to date along with current “on-the-books” state and federal regulatory measures. Both factors (emissions and visibility impairment) are addressed in Indiana’s RH SIP with future emission reductions anticipated. These reductions will be appropriately evaluated in upcoming implementation periods as the natural visibility goals are realized by 2064.

United State Department of Interior – National Parks Service (email from Anne M Thomas/ letter from Herbert C Frost received on November 9, 2021)

Comment 1
The NPS maintains that it is not reasonable for IDEM to exempt electric generating units (EGUs) from four-factor analyses. Regional modeling results show that Indiana EGUs contribute significantly to visibility impairment at multiple Class I areas, accounting for 7% of total visibility impact at Mammoth Cave NP. In fact, five of the top ten facilities impacting Mammoth Cave NP are Indiana EGUs. As previously shared, our analyses demonstrate there may be cost-effective controls available at several EGUs. We recommend IDEM conduct four-factor analyses for these facilities and include cost-effective controls in the regional haze SIP.

Response 1
See the “Responses 2 and 3” under the U. S. EPA summary of comments and responses section on page 1 of this document for this response.

Comment 2
Based on IDEM’s original and revised analyses, we maintain that there are cost-effective control options available at several facilities including Alcoa Warrick, Burns Harbor, and Greencastle Cement. We recommend that IDEM implement all cost-effective controls to reduce haze causing emissions.

Comment 3
Controls that we consider reasonable were rejected by IDEM as unnecessary “considering the significant progress already made towards achieving the national visibility goal.” In response, we note that the 2017 preamble to the Regional Haze Rule, the August 2019 Guidance, and the recent July 2021 clarification memorandum all clearly state that having made significant progress is not a "safe harbor" that can be used to dismiss otherwise reasonable controls (82 FR at 3099, EPA 2019 RH Guidance §II(5)(a), EPA 2021 Memo §5.4).

Comment 4
Finally, IDEM concluded that the contribution to visibility impairment from the state’s sources is not sufficient to justify additional controls. We note that the visibility benefit of emissions reductions from individual facilities is not one of the four statutory factors that should be considered to determine whether controls are reasonable and should not be used to reject reasonable controls (Clean Air Act §7491, 40 CFR 51.308(f)(2)(ii), EPA 2021 Memorandum §5.2).

Responses 2, 3, and 4
See “Responses 6, 8, 10, 11, and 12” under the U. S. EPA summary of comments and responses section on page 6 of this document for this response.

Visibility Improvement State and Tribal Association of the Southeast (VISTAS) Member States: Tennessee (email from James Johnston received on November 4, 2021) **and North Carolina** (email from Randy Strait received on November 10, 2021)

Comment
In Section 8.0 and Appendix D of the draft SIP, IDEM discussed the substantial decrease in EGU NO_x and SO_2 emissions from Indiana's EGUs, including specific information for Gibson and Rockport, between 2007 and 2019 and the additional projected decreases for 2028. Those sections of the RH SIP also indicate that IDEMs projected 2028 emissions for Gibson and Rockport are similar to VISTAS 2029 projections.

Since IDEM's projected 2028 emissions are similar to those provided by VISTAS and IDEM has not provided information to counter the NCDAQ's and VISTAS finding that Gibson and Rockport significantly impact visibility impairment at Great Smoky Mountains National Park and Joyce-Kilmer-Slickrock Wilderness Area, the NCDAQ requests that IDEM include four-factor analyses for both of these facilities in their final Regional Haze SIP for the second implementation period. Alternatively, IDEM could include an effectively controlled analysis or anticipated shutdown information for one or both of these facilities.

Response
IDEM has drafted a formal response to the VISTAS interstate consultation letter, which will be completed and sent to VISTAS and its member states and tribal organization after IDEM has completed its work on the draft Indiana RH SIP for the second implementation period. See IDEM's formal response to the VISTAS Inter-RPO Ask in Appendix AA of this document.

Mid-Atlantic/Northeast Visibility Union (MANE-VU) (email from Paul Miller received on November 5, 2021) **and Member State New Jersey** (email from Sharon Davis received on November 1, 2021)

MANE-VU Inter-Regional Planning Organization (RPO) Ask
MANE-VU's technical analysis identified visibility-impairing emissions from Indiana and other upwind states as reasonably anticipated to contribute to visibility impairment at MANE-VU Class I areas. Based on this analysis, MANE-VU developed a "MANE-VU Ask" that was sent to Indiana and the other identified states with five requests for consideration during the upwind states' second regional haze SIP planning effort. With this letter, MANE-VU is providing our overarching perspective on how well IDEM's draft addresses each of these requests. MANE-VU makes note of the past and future EGU retirements and emissions reductions described in Sections 8.1.1 and 8.3 of IDEM's draft. Nevertheless, MANE-VU respectfully requests that its Ask items be addressed in IDEM's regional haze SIP as described in the comments that follow.

Ask #1
EGUs ≥ 25 MW with installed controls, ensure that controls are run year-round. IDEM's draft SIP does not address MANE-VU Ask #1. As described in Section 7.4 of the IDEM draft, IDEM has elected to defer analysis of its EGU sector until the third implementation period. While the workload distribution of source category analysis to different implementation periods is allowed under EPA guidance, IDEM's approach of deferring analysis of its EGU sector is inconsistent with MANE-VU's Inter-RPO Ask for the second implementation period. To this end, MANE-VU notes the Indiana EGU emissions reductions that occurred between 2009 and 2019 as described in Section 8 of IDEM's draft. Nevertheless, MANE-VU reiterates its request that IDEM pursue enforceable mechanisms to ensure that EGUs ≥ 25 MW with installed controls run those controls year-round.

Ask #2
For emissions sources having a 3.0 Mm-1 impact or greater at MANE-VU Class I areas, perform a four-factor analysis. The IDEM draft does not address MANE-VU Ask #2. The Indiana Michigan Power Company (dba American Electric Power) Rockport Plant (Facility ID 6166) was identified by MANE-VU technical analysis as a facility with the potential for 3.0 Mm-1 impact or greater at one or more of MANE-VU's Class I areas. MANE-VU notes the emissions controls and reductions for the Rockport Plant discussed in Section 8.5 of the IDEM draft, including the continuous operation of SCRs and enhanced DSI systems. Nevertheless, MANE-VU respectfully requests that a four-factor analysis be performed for the Rockport Plant, consistent with MANE-VU's Ask #2, to determine the reasonableness of more stringent control efficiencies or stricter emissions limits.

Ask #3
Adopt an ultra-low sulfur fuel oil standard. The IDEM draft does not address the MANE-VU ultra-low sulfur fuel oil Ask. MANE-VU respectfully re-iterates its request that Indiana adopt ultra-low sulfur fuel oil standards as part of its long-term strategy or demonstrate in its SIP why it would not be feasible to do so. For distillate oil, this would be essentially the equivalent of on-road diesel, which is already widely 3 available. We note that all MANE-VU states have successfully adopted low sulfur fuel oil requirements.

Ask #4
For EGUs and other large sources, pursue enforceable mechanisms to lock in lower emission rates. MANE-VU notes the EGU emissions reductions described in Section 8 of the IDEM draft, including those that have come about via enforceable mechanisms, such as consent orders. However, IDEM does not directly address MANE-VU's Ask #4 in its draft SIP.

Ask #5
Encourage and promote energy efficiency and clean technologies. The IDEM draft does not address Ask #5. MANE-VU respectfully asks that IDEM consider, and report in its SIP, measures or programs in Indiana that reduce emissions by encouraging energy efficiency and promoting cleaner energy technologies. Rather than a focus on energy markets, this would be a discussion within IDEM's haze SIP of the energy efficiency measures and clean energy programs under consideration or currently operating in Indiana. Unlike MANE-VU's other Ask items, MANE-VU does not necessarily intend that these measures be enforceable or included as part of a state's long-term strategy. But because such programs can reduce emissions and therefore benefit visibility, MANE-VU is asking its upwind state partners to consider and report such measures in their haze SIPs.

Response to MANE-VU Inter-RPO Ask
IDEM has drafted a formal response to the MANE-VU Inter-RPO Ask, which will be finalized and sent to MANE-VU and its member states and tribal organizations after IDEM has completed its work on the draft Indiana RH SIP for the second implementation period. See IDEM's formal response to the MANE-VU Inter-RPO Ask in Appendix AA of this document.

MANE-VU Section-Specific Comments

Comment 1
7.3 Q/d Screening Analysis for Source Selection
MANE-VU respectfully asks IDEM to describe in its SIP the technical basis for selecting 5 as the Q/d screening threshold for screening sources.

Response 1
As described in Section 7.3 of the SIP, the Q/d threshold value of 5 was chosen due to the number of sources that met this criterion and the commitment among LADCO member states to be consistent in their decision making throughout the SIP development process. Indiana believed that evaluating the 20 highest emitting sources of NO_x and SO_2 pollution in the state would provide an adequate and representative number of sources to be evaluated and observed that most of the other LADCO states choose a similar number of sources for evaluation.

Comment 2
23.1 Class I Area Selection
At the bottom of page 199, below Table 23-2, the text states, "Results for all Class I areas analyzed show 2014-2018 baseline monitored values, as determined through the IMPROVE monitoring data, are lower than the modeled visibility impacts at each Class I area for 2028, based on the 2011 emissions[.]" Although this statement is true for some of the Class I areas shown in Table 23-2, it does not appear to be true for many others.

Response 2
This is correct; therefore, the sentence this comment refers to has been changed from all Class I areas to most Class I areas.

Comment 3
23.11 Brigantine Natural Wilderness Area, NJ; and Lye Brook National Wilderness Area, VT (MANE-VU)
This section asserts that "on-the-books" measures, along with federal measures, are such that the meeting of reasonable progress goals (RPGs) will not be impeded. This section concludes that, as a result, no further analysis for this SIP will be taken. MANE-VU does not challenge the assertion that the meeting of RPGs will not be impeded but re-iterates the fact that RPGs themselves are not enforceable and that the overarching goal of CAA 169A and the regional haze rule is to make progress towards the goal of natural visibility conditions by 2064. As emissions sources such as EGUs become better controlled, smaller additional emissions reductions from these sources, or emissions reductions from other source types, become necessary to make incremental improvements in visibility and to ensure that downward trends in monitored visibility metrics continue. Therefore, MANE-VU further re-iterates its request that IDEM do additional work and analysis to ensure that MANE-VU's Inter-RPO Ask is addressed in its SIP such that incremental progress is made at MANE-VU Class I areas affected by Indiana emissions.

Response 3
See "Response 2 and 3" under the U. S. EPA summary of comments and responses section on page 1 of this document for this response.

Comment 4
25.0 20% CLEAREST DAYS ANALYSIS
The first sentence in this section states, "Results for all Class I areas analyzed show 2014-2018 baseline monitored values, as determined through the IMPROVE monitoring data, are lower than the modeled visibility impacts at each Class I area for 2028, based on the 2011 emissions[.]" Although this statement is true for almost all of the Class I areas shown in Table 25-1, it does not appear to be true for Isle Royale, Brigantine, and Lye Brook.

Response 4
This is correct; therefore, the sentence this comment refers to has been changed from all Class I areas to most Class I areas.

New Jersey (email from Stella Oluwaseun-Apo received on November 1, 2021)

Response to New Jersey Specific Comments
New Jersey is a MANE-VU member state. Comments included in the state's correspondence are also included in the MANU-VU correspondence; therefore, responses to New Jersey specific comments can be found in IDEM's formal response to the MANE-VU Inter-RPO Ask. See IDEM's formal response to the MANE-VU Asks in Appendix AA of this document.

Duke Energy (email from Aaron Flynn received on November 15, 2021)

Comment 1
It is important to note that the units are subject to the Mercury and Air Toxics Rule Subpart UUUUU, which requires that the installed emission controls be operated at all times coal is burned and which uses SO_2 reductions as a surrogate for acid gases. The Draft SIP should reflect this.

Response 1
Comment 1 has been incorporated into the Draft SIP under Section 9.3.

All other comments in Duke Energy's comments document were found to be in line with the points IDEM already makes in one form or another for the EGU source sector in the Draft SIP. Therefore, these comments were not incorporated into the Draft SIP because IDEM prefers the existing language as it is throughout the document.

United States Steel Corporation (US Steel), Gary Works (email from Jacob Blahut received on November 15, 2021)

IDEM appreciates the comments submitted by US Steel in support of Indiana's draft RH SIP, which do not require a response from IDEM. A copy of the comments submitted can be found in Appendix Y.

Alcoa Warrick Operations (email from Thomas Shaw received on November 3, 2021)

Comment 1
Alcoa would like to correct the cost effectiveness numbers for the Flue Gas Desulfurization for Potlines 2-6 which is $16,800 per ton and the Anode Baking Ring Furnace which is $45,500 per ton as noted on page 2 of the August 13, 2021, report from Burns & McDonnell.

Response 1
The cost effectiveness numbers for Potlines 2-6 and the Anode Baking Ring Furnace were corrected in the Indiana RH SIP for the Second Implementation Period document and Appendix J.

Buzzi Unicem USA (Buzzi Unicem) (email from Michelle Ferguson received on November 15, 2021)

Comment 1
The comments submitted by Buzzi Unicem relate to the different pollution control measures chosen for four-factor analysis, the percentage of control attributed to those measures, and the feasibility of installing them on the cement kilns at the Greencastle facility. The Buzzi Unicem's comments also explain how the cost information in the cost estimate and cost effectiveness evaluation don't accurately represent the costs associated with installing the controls evaluated on the Greencastle cement kilns.

Response 1
IDEM requested cost information from Buzzi Unicem to assist with developing cost estimates for potential control measures evaluated for the Greencastle cement kilns. However, the source had not invested any resources or time into developing information related to upgrades to existing pollution control systems or the installation of new pollution control systems on the cement kilns that would be helpful to IDEM in developing the cost estimates for controls. Therefore, IDEM prepared a more general analysis of the potential controls and costs to install them for the Greencastle kilns using existing information available to the agency.

IDEM used the LADCO whitepaper procured for LADCO member states to use in developing their four-factor analyses for the second implementation period; the cement kiln control device information collected and shared by the Federal Land Managers; and the cost estimate information provide by Lehigh for SNCR and SCR control systems to develop the four-factor analyses for the cement kiln source category and the source-specific analysis for the Greencastle cement kilns. IDEM acknowledges that the information interpolated from the cost estimates are not precise estimates specific to the Greencastle kilns; however, the information provided in the Buzzi Unicem comments submitted do not provide enough source-specific information to develop more accurate cost estimate information or decisively determine the feasibility of the controls evaluated. Therefore, Buzzi Unicem's comments are appreciated and included in Appendix W; but no changes will be made to the cement kiln four-factor analysis as a result of the source's comments.

Lehigh Hanson, Inc. (Lehigh) (email from Adam N. Swercheck received November 12, 2021)

A four-factor analysis for the Lehigh Mitchell facility was not conducted due to the fact that the company was issued a Title V permit and is in the process of constructing a new state-of-the-art facility to replace the old facility. The details of Lehigh's plans for the new facility are included in the RH SIP, therefore the company's comments are appreciated and included in Appendix W; but no changes will be made to the cement kiln four-factor analysis as a result of the source's comments.

Indiana Energy Association (IEA) (email from Mindy Westrick Brown received on November 12, 2021)

IDEM appreciates the comments submitted by IEA in support of Indiana's draft RH SIP, which do not require a response from IDEM. A copy of the comments submitted can be found in Appendix Y.

National Parks Conservation Association (NPCA) (email from Colin Deverell received on October 28, 2021)

Comment 1
Fully analyze reasonable progress emission controls for all coal plants in the state in this planning period. It is commonplace for coal plants to have scrubbers that reduce upwards of 98% of SO_2 emissions and selective catalytic reduction systems to reduce 95% of emissions of NO_x. Indiana cannot disregard these controls or upgrades to those facilities that already have them installed with weak performance.

Response 1
See the "Responses 2 and 3" under the U. S. EPA summary of comments and responses section on page 1 of this document for this response.

Comment 2
Evaluate all applicable controls for non-power plant sources and correct the cost of controls calculations.

Response 2
See "Responses 6, 8, 10, 11, and 12" under the U. S. EPA summary of comments and responses section on page 6 of this document for this response.

Comment 3
Thoroughly assess environmental justice impacts.

Response 3
The impact of emission sources on regional haze occurs downwind and the Regional Haze Rule addresses visibility impacts on Class I areas. Therefore, Indiana's RH SIP is only addressing emissions and visibility impacts on surrounding Class I areas. As U.S. EPA continues to evaluate environmental justice issues and how states can consistently and equitably address these issues, Indiana will continue to base its regulatory and permitting decisions on existing federal and state regulations that are protective of all Indiana citizens in all areas of the state.

Comment 4
Set enforceable retirements for any sources being counted on for pollution reduction.

Response 4
See "Responses 4, 5, 7, and 9" under the U. S. EPA summary of comments and responses section on page 4 of this document for this response.

Sierra Club (email from Rebecca Dien-Johns received on October 28, 2021)

Comment 1
Require polluters to reduce harmful air pollution, more specifically sulfur dioxide and nitrogen oxides, to protect visibility at our national parks and the public health of Hoosiers.

Responses 1
Table 8-4 of Indiana's RH SIP details the projected emissions reductions anticipated for NO_x emissions of 59% and SO_2 emissions of 52% from EGUs. This is a result of retirements of EGU boilers and federal regulations that have already gone into effect. Overall, all anthropogenic emissions from Indiana are projected to decrease by 42% of NO_x from 2016 to 2028 while SO_2

emissions will decrease by 32%, as described in Indiana's RH SIP, Section 5.15. These reductions will continue to improve visibility impairment at Class I areas as well as keep air quality throughout Indiana well below health-based air quality standards.

Sierra Club, National Parks Conservation Association, The Coalition to Protect America's National Parks, Just Transition Northwest Indiana, Hoosier Environmental Council, Izaak Walton League, and Save the Dunes (email from Tony Mendoza received on November 15, 2021)

Comment 1
IDEM arbitrarily and unlawfully failed to conduct reasonable progress analyses or consider emissions reductions for many of the state's largest sources of visibility impairment, including the entire electric generation unit ("EGU") sector.

Comment 2
Rather than conduct four-factor analyses for Indiana's EGUs, as required by the Clean Air Act and the Regional Haze Rule, IDEM impermissibly relied on unenforceable and unverifiable emission reductions from planned retirements or reductions in utilization at Indiana EGUs.

Comment 3
IDEM impermissibly exempts EGUs from further control analysis based on the state's purported compliance with the Uniform Rate of Progress.

Comment 4
The proposed SIP fails to properly establish reasonable progress goals and fails to consider the statutory reasonable progress factors for EGUs, and instead relies on factors that Congress did not intend for states to consider to exempt those sources from reasonable, cost-effective controls.

Comment 6
IDEM's control evaluation for the state's EGU sector fails to satisfy the Regional Haze Rule's requirement that the state include the "robust" technical demonstration showing that no additional controls are reasonable.

Comment 7
As explained below and in the attached Kordzi Report, IDEM failed to evaluate cost-effective and achievable emission reductions for several of Indiana's largest sources, including Gibson, Rockport, Warrick, Clifty Creek, Petersburg, Cayuga, and A.B. Brown. If the state had conducted four-factor analyses for those sources, it is clear that cost-effective controls are available.
Responses 1, 2, 3, 4, 6, and 7
See "Responses 2 and 3" under the U. S. EPA summary of comments and responses section on page 1 of this document for this response.

Comment 5
IDEM improperly defers making any four-factor determinations based on purported emission reductions from existing Clean Air Act programs.

Comment 8
For the sources for which IDEM did include four-factor analyses, the agency cherry picked emitting units from the facilities and did not consider all
emitting units.

Comment 9
IDEM's analyses for control analyses for the following seven sources, Greencastle facility, Indiana Harbor East and West Steel Mills Burns Harbor Steel Mill, U.S. Steel Gary Facility, SABIC Plastics, Warrick Newco (formerly Alcoa Warrick) and Cokenergy, rely on inaccurate and missing information, inflated costs and shortened useful life factors and otherwise are woefully inadequate and fundamentally inconsistent with the Clean Air Act and the Regional Haze Rule.

Comment 10
IDEM failed to consider all emission control options for those sources evaluated, including the most stringent measures.

Comment 11
IDEM's proposed SIP fails to include documentation necessary to independently review the availability of cost-effective controls.

Response 5, 8, 9, 10, and 11
See "Responses 6, 8, 10, 11, and 12" under the U. S. EPA summary of comments and responses section on page 6 of this document for this response.

Comment 12
IDEM's interstate consultation is inconsistent with the requirements of the Regional Haze Rule.

Response 12
IDEM has acknowledged receipt of the asks received by other regional planning organizations and individual states. However, due to the delay in receiving the results from LADCO's source apportionment modeling until June of 2021, IDEM decided to complete development of Indiana's its RH SIP and then submit the interstate consultation responses along with the final SIP to EPA. IDEM's interstate consultation responses are included in Appendix AA of the final submittal.

Comment 13
IDEM must reevaluate, consider and incorporate the Federal Land Managers' comments.

Responses 13
IDEM summarized and addressed the Federal Land Managers comments in Appendix U and the agency's responses to issues raised by the Federal Land Managers are consistent with IDEM's responses to other similar comments received during the public comment period.

Comment 14
The proposed SIP fails to evaluate environmental justice or disproportionately impacted communities' impacts, resulting in a proposed SIP that does not reduce emissions and minimize harms to environmental justice and other disproportionately impacted communities, as strongly encouraged by the EPA's clarifying memo.

Response 14
While environmental justice (EJ) is an important issue and should be addressed on a case-by-case basis, regional haze addresses the formation of haze from secondary pollutants of which this formation occurs from photochemical reactions. These photochemical reactions can take place several if not hundreds of kilometers away from an emission source. Prevention of Significant Deterioration (PSD) and associated modeling tools are more appropriate regulatory mechanisms to address EJ. EJ should not be a consideration in determining long term strategy decisions for regional haze.

Clarification Responses to statements made in the Sierra Club Comments

1st Statement on Pg. 10, Section II
Based on 2016 emissions, IDEM established screening threshold Q/d value of 5 to screen out sources with either low emissions or located at far distances from Class I areas that would not have visibility impacts.

Clarification Response to 1st Statement
IDEM used 2018 emissions to conduct its Q/d screening, as stated in the draft RH SIP, page 43.

2nd Statement on Pg. 46, Section III.A
Only Missouri and Arkansas were consulted.

Clarification Response to 2nd Statement
IDEM consulted with VISTAS and MANE-VU over the course of the SIP document development period. IDEM has evaluated its visibility impacts on all Class I areas in the eastern half of the United States. Specific responses to each state and multi-jurisdiction organization areas, in which consultation occurred, are included in the final SIP.

3rd Statement on Pg. 46, Section III.A
IDEM must re-initiate consultation with Missouri since Graph 23-18 shows the modeled visibility impact at Mingo for 2028 appears on the unadjusted glidepath for 2028.

Clarification Response to 3rd Statement
The glidepath charts are graphical representations of modeled and monitored results for each Class I area. The URP is the uniform rate of visibility progress in which 2000-2004 represents the baseline period of the URP and 2064 represents the endpoint where the deciview value of the URP is assumed for the purpose of analysis to reach natural visibility conditions. The line between 2000 and 2064 is the graphical representation of this data. IDEM reviewed the LADCO modeling output that determined the URP and the modeled URP value for 2028 was calculated at 19.44 deciviews. Therefore, the modeled visibility impairment value for Mingo of 18.94 deciviews is 0.5 deciviews below the 2028 URP value of 19.44 deciviews. Since the modeled visibility value is below the URP for Mingo, a “robust demonstration” is not required. LADCO’s modeled output can be found in association with the LADCO “Modeling and Analysis for Demonstrating Reasonable Progress for the Regional Haze Rule 2018-2028 Planning Period - Technical Support Document“ as listed in Appendix L of the RH SIP.

4th Statement on Pg. 55, Section V
Sierra Club stated Indiana ranks #1 in toxics releases per square mile.

Clarification Response to 4h Statement
U.S. EPA's Toxic Release Inventory (TRI) reporting incorporates releases into the air, water, land disposal or transferred off-site for disposal. Indiana's total toxic air releases are only a portion of this total and have consistently declined by nearly 70% since 2006 with continued reductions in air toxics anticipated.

5th Statement on Pg. 56, Section V
Sierra Club stated according to EPA, U.S. Steel - Gary Works is the state's top polluter, producing 22.5 million pounds of pollutants.

Clarification Response to 5h Statement
U.S. EPA's TRI reporting incorporates releases into the air, water, land disposal or transferred off-site for disposal and the air emissions portion of U.S. Steel's releases were 312,203 pounds, accounting for 1.4% of its total releases.

General Public Comments

Numerous emails were received from individuals who made the same general comments summarized below.

Comment 1
Indiana's RH SIP contains no new reductions in pollution.

Comment 2
Indiana's RH SIP plan must require polluters to reduce SO_2/NO_x

Response 1 and 2
Table 8-4 of Indiana's RH SIP details the projected emissions reductions anticipated for NO_x emissions of 59% and SO_2 emissions reductions of 52% from EGUs. This is, in part, a result of retirements of EGU boilers and federal regulations that have already gone into effect. Overall, all anthropogenic NO_x emissions from Indiana are projected to decrease by 42% from 2016 to 2028 while all anthropogenic SO_2 emissions will decrease by 32% over the same time period, as described in Indiana's RH SIP, Section 5.15.

Comment 3
Indiana's RH SIP fails to make reasonable progress at Class I areas and is woefully inadequate.

Comment 4
Set enforceable retirements for any source the state is counting on for pollution reduction.

Response 3 and 4
See "Responses 4, 5, 7 and 9" under the U. S. EPA summary of comments and responses section on page 4 of this document for this response.

Comment 5
Indiana's RH SIP fails to require cost-effective controls/enforceable retirements.

Comment 6
Evaluate all applicable controls for non-power plants and correct cost analysis.

Comment 7
Require US Steel and Alcoa to reduce pollution and protect parks and public health.

Response 5, 6, and 7
See "Responses 6, 8, 10, 11, and 12 under the U. S. EPA summary of comments and responses section on page 6 of this document for this response.

Comment 8
Fully analyze emission controls for all coal plants in the state.

Comment 9
Require Gibson and Petersburg to reduce pollution and protect parks and public health.

Response 8 and 9
See "Responses 2 and 3 under the U. S. EPA summary of comments and responses section on page 1 of this document for this response.

Comment 10
IDEM should thoroughly assess environmental justice.

Response 10
Indiana assesses all areas of the state equally according to current state and federal regulations and uses all available existing data and information to determine air quality impacts. PSD and associated modeling tools are more appropriate regulatory mechanisms to address EJ issues. EJ should not be a consideration in determining long term strategy decisions for regional haze in states without Class I areas.

Emails received from individuals who made general comments are summarized below.

Bill Walters

Comment
Only Texas produces more CO_2 from coal than Indiana.

Response
Without proper context of the commenter's statistical reference and the source of this ranking, it is difficult to provide a direct response. IDEM retrieved U.S. EPA emissions data for states' breakdown of carbon dioxide (CO_2) emissions from 2008 to 2018 (the time period for the first implementation period for regional haze) and Indiana is ranked 8th in CO_2 emissions nationally and 3rd among Midwest states. Indiana is trending downward over this period of time with a 16.5% drop in CO_2 emissions from fossil fuel combustion. www.epa.gov/sites/default/files/2020-10/documents/state_co2_emissions_from_fossil_fuel_combustion_1990-2018.pdf. Additionally, more recent information for 2017 to 2020 from U.S. EPA's Clean Air Market Division (CAMD) shows Indiana CO_2 emissions from electric utilities are dropping. Comparison of 2017 to 2019 showed a 7% drop in CO_2 emissions while 2020 CO_2 emissions, no doubt impacted from Covid-19, showed a 22.7% drop, ahead of the national average decrease from 2017 to 2020 of 17%.

Kimberly Wellman

Comment
EPA's Toxic Release Inventory shows Indiana releases most chemicals per square mile (2019)

Response
U.S. EPA's TRI reporting incorporates releases into the air, water, land disposal or transferred off-site for disposal. Indiana's total toxic air releases have consistently declined since 2006 by nearly 70% with continued reductions in air toxics anticipated.

Dlynn Melo

Comment
Hard to breath on days where temperature inversions push down smoke/haze.

Response
IDEM would encourage all Indiana citizens refer to the SmogWatch air quality forecasting website for current and forecasted ozone and fine particulates concentrations. Air quality forecasts take into account natural pollution resulting from wildfires and desert dust events as well as weather conditions in which fine particulates or ozone develop over time in any area of the state. The SmogWatch link is https://apps.idem.in.gov/smogwatch/Today.aspx

Diana Allen

Comment
Worsening air pollution worsens her asthma.

Response
Table 25-1 of Indiana's RH SIP demonstrates the vast emissions reductions realized throughout the state with reduction of NO_2 emissions of 65% and SO_2 emissions reductions equating to over 90% since 2007. IDEM would encourage the public to refer to the SmogWatch air quality forecasting website for current and forecasted ozone and fine particulates concentrations. Air quality forecasts take into account natural pollution resulting from wildfires and desert dust events as well as weather conditions in which fine particulates or ozone develop over time in an area. The SmogWatch link is https://apps.idem.in.gov/smogwatch/Today.aspx.

Thomas Sherer

Comment
Without sanctions and penalties, haze plan will cause more haze.

Response
Indiana's Regional Haze SIP demonstrates tremendous emissions reductions that have greatly improved visibility at Class I areas throughout the eastern half of the country. Indiana sources' projected emissions by the year 2028 are even lower than current emissions so Indiana's visibility impacts will be even less on surrounding Class I areas.

Sharon Smith

Comment
Family deals with COPD which doctors say is caused by air pollution. Polluters get a free pass to pollute.

Response
IDEM would encourage the public to refer to the SmogWatch air quality forecasting website for current and forecasted ozone and fine particulates concentrations. Air quality forecasts take into account natural pollution resulting from wildfires and desert dust events as well as weather conditions in which fine particulates or ozone develop over time in an area. The SmogWatch link is https://apps.idem.in.gov/smogwatch/Today.aspx.

Jim Merkle

Comment
Concerned about continuing releases into Lake Michigan.

Response
While this does not directly relate to regional haze, IDEM's Office of Water Quality is investigating recent releases and continues to work with the responsible companies, local and county leaders and concerned citizens on addressing these incidents.

Dania Straughan

Comment
Pregnant mom with asthma, reduce toxic waste that she is forced to breathe.

Response
Indiana's Regional haze SIP is focused on sulfur dioxide and nitrogen oxides impacts on visibility on all federal Class I areas. It should be noted that Indiana's total toxic air releases have consistently declined since 2006 by nearly 70% with continued reductions in air toxics anticipated. IDEM would encourage all Indiana citizens to refer to the SmogWatch air quality forecasting website for current and forecasted ozone and fine particulates concentrations. Air quality forecasts take into account natural pollution resulting from wildfires and desert dust events as well as weather conditions in which fine particulates or ozone develop over time in an area. The SmogWatch link is https://apps.idem.in.gov/smogwatch/Today.aspx.

Arianna Grazziani

Comment
Current laws don't protect health and causes destruction of property.

Response
The National Ambient Air Quality Standards consist of primary and secondary standards as determined by science experts and health officials and adopted into U.S. EPA's Code of Federal Register as approved federal regulations. The secondary standards are designed to protect the public welfare from adverse effects, including those related to effects on soils, water, crops, vegetation, man-made (anthropogenic) materials, animals, wildlife, weather, visibility, and climate; damage to property; transportation hazards; economic values, and personal comfort

and well-being. Indiana is currently meeting all primary and secondary standards at all its ambient air quality monitoring sites for all criteria pollutants throughout the state.

Mark Nowotarski

Comment
Indiana ranks #1 in toxic releases per square mile, 3rd in carbon emissions, has 5 super polluters.

Response
EPA's TRI reporting incorporates releases into the air, water, land disposal or transferred off-site for disposal. Indiana's total air toxic releases have consistently declined since 2006 by nearly 70% with continued reductions in air toxics anticipated. IDEM has retrieved U.S. EPA emissions data for states' breakdown of carbon dioxide (CO_2) emissions from 2008 to 2018 (the time period for the first implementation period for regional haze) and Indiana is ranked 8th in CO_2 emissions nationally and 3rd among Midwest states. Indiana is trending downward over this period of time with a 16.5% drop in CO_2 emissions from fossil fuel combustion. www.epa.gov/sites/default/files/2020-10/documents/state_co2_emissions_from_fossil_fuel_combustion_1990-2018.pdf.

Additionally, more recent information for 2017 to 2020 from U.S. EPA's CAMD shows Indiana CO_2 emissions continue to drop. Comparison of 2017 to 2019 CO_2 emissions showed a 7% drop while 2020 CO_2 emissions, no doubt impacted from Covid-19, showed a 22.7% drop, ahead of the national average decrease in CO_2 emissions from 2017 to 2020 of 17%.

Linda Evinger

Comment
Indiana is a polluted state which leads other companies and individuals to not locate/live in the state. Protect the bees, bats, wildlife.

Response
Indiana's Regional haze SIP is focused on sulfur dioxide and nitrogen oxides impacts on visibility on all federal Class I areas. Table 25-1 of Indiana's RH SIP demonstrates the vast emissions reduction realized throughout the state with reduction of NO_x emissions of 65% and SO_2 emissions reductions equating to over 90% since 2007. It should be noted that the National Ambient Air Quality Standards consist of primary and secondary standards. The secondary standards are designed to protect the public welfare from adverse effects, including those related to effects on soils, water, crops, vegetation, man-made (anthropogenic) materials, animals, wildlife, weather, visibility, and climate; damage to property; transportation hazards; economic values, and personal comfort and well-being. Indiana is currently meeting all secondary standards for all criteria pollutants.

Drew Davis

Comment
Protect all National Park Service sites in Indiana, Indiana State Parks and State Historical sites.

Response
The National Ambient Air Quality Standards consist of primary and secondary standards. The secondary standards are designed to protect the public welfare from adverse effects, including

those related to effects on soils, water, crops, vegetation, man-made (anthropogenic) materials, animals, wildlife, weather, visibility, and climate; damage to property; transportation hazards; economic values, and personal comfort and well-being. Indiana is currently meeting all secondary standards for all criteria pollutants at all ambient air quality monitors throughout the state.

Michael Bean

Comment
IDEM must reduce and limit SO_2/NO_x and increase regulations/monitoring of SO_2/NO_x

Response
Table 8-4 of Indiana's RH SIP details the projected emissions reductions anticipated for NO_x emissions of 59% and SO_2 emissions of 52% from EGUs. This is a result of retirements of EGU boilers and federal regulations that have already gone into effect. Overall, all anthropogenic emissions from Indiana are projected to decrease by 42% of NO_x emissions from 2016 to 2028 while SO_2 emissions will decrease by 32%, as described in Indiana's RH SIP, Section 5.15. As such, Indiana has determined that current "on-the-books" regulatory measures and monitoring of NO_x and SO_2 emissions are adequate to address regional haze for sources throughout the state based on the tremendous visibility progress made to date. NO_x and SO_2 emissions are addressed in Indiana's RH SIP with future emission reductions anticipated.

Richard Hill

Comment
Maintain clean natural views/healthy, breathable air. Lives near Clifty Creek which needs to comply with regulations

Response
IDEM compliance staff have confirmed that Clifty Creek complies with its permit conditions and meets compliance and monitoring requirements. There have been no excess emissions issues from the facility and Clifty Creek submits timely monitoring and compliance reports.

Susan Thomas

Comment
Photosynthesis is disrupted, and native plants are damaged.

Response
The National Ambient Air Quality Standards consist of primary and secondary standards. The secondary standards are designed to protect the public welfare from adverse effects, including those related to effects on soils, water, crops, vegetation, man-made (anthropogenic) materials, animals, wildlife, weather, visibility, and climate; damage to property; transportation hazards; economic values, and personal comfort and well-being. Indiana is currently meeting all secondary standards for all criteria pollutants throughout the state.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-26-46
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	)))))	Order No. 202-26-47

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 70
Konidena September Decl.

DECLARATION OF RAO KONIDENA

I, Rao Konidena, declare as follows:

1. I am an electrical engineer and the principal of Rakon Energy LLC, an engineering firm that consults on energy markets such as the Midcontinent Independent System Operator (MISO).

2. I spent 15 years at MISO forecasting resource adequacy and working on policy matters, including in management and in public-facing roles. I have extensive experience on engineering and planning issues associated with distributed energy resources, storage, and transmission planning, advising state commissions, consumer advocates, and clean energy developers nationwide.

3. In my professional opinion, for the reasons discussed below, neither MISO's alerts and operating conditions during June 2025 nor MISO's seasonal capacity market structure provide a factual basis for the Order's findings of a shortage of electric energy and a shortage of facilities for the generation of electricity in portions of the Midwest region of the United States. The MISO alerts and operating conditions cited by the DOE are not evidence of an actual shortage of electric energy because MISO had sufficient tools and authority to keep the lights on and almost certainly would have maintained reliability and kept the lights on absent J.H. Campbell's continued operation. Even at peak demand on June 23, 2025, MISO had a surplus more than ten times greater than the amount of power Campbell was providing. Meanwhile, the seasonal capacity market structure reflects a forward-looking reform to improve the accuracy of crediting generators in non-summer seasons, align obligations with actual seasonal risks, and protect consumers from unnecessary costs.

A. Education and Experience

4. My office is located in Roseville, Minneapolis-St. Paul Metro area, Minnesota. My professional and educational experience is summarized in the curriculum vitae attached to this declaration (Attachment A).

5. I received a Bachelor of Engineering in Electrical and Electronics Engineering from Bangalore University, a Master of Science in Electrical Engineering from the University of Texas at Arlington, and a Master of Business Administration from the University of Minnesota.

6. I have more than two decades of experience in U.S. wholesale electricity markets, distribution system planning, and the integration of distributed energy resources. As Principal of Rakon Energy LLC, I have provided expert testimony before state commissions and FERC on issues involving resource adequacy, transmission planning, distributed energy resources (DERs), and energy storage. My clients have included retail customer aggregators, state attorneys general, generation developers, consumer advocates, and environmental organizations. Through this work, I have analyzed and advised on the implications of utility distribution system plans, distributed energy resource tariffs, interconnection rules, and the evolving seasonal capacity constructs of organized wholesale markets.

7. From 2003 to 2018, I served at MISO in roles ranging from resource forecasting to policy studies. At MISO, I led studies on demand response, energy efficiency, distributed generation potential, and grid-scale storage, as well as independent load forecasting and economic transmission planning. I represented MISO in national and international forums, including the Department of Energy's U.S. DRIVE technical team and the GO-15 group of global grid operators. This combination of independent consulting and ISO experience provides me with a deep understanding of how MISO's market structures, its planning processes, and its operational practices affect reliability, investment, and consumer costs.

B. Purpose of Declaration

8. I am familiar with the U.S. Department of Energy's and Energy Secretary Chris Wright's ("DOE") August 20, 2025 order to MISO and Consumers Energy Company (Order No. 202-25-7) ("Order").

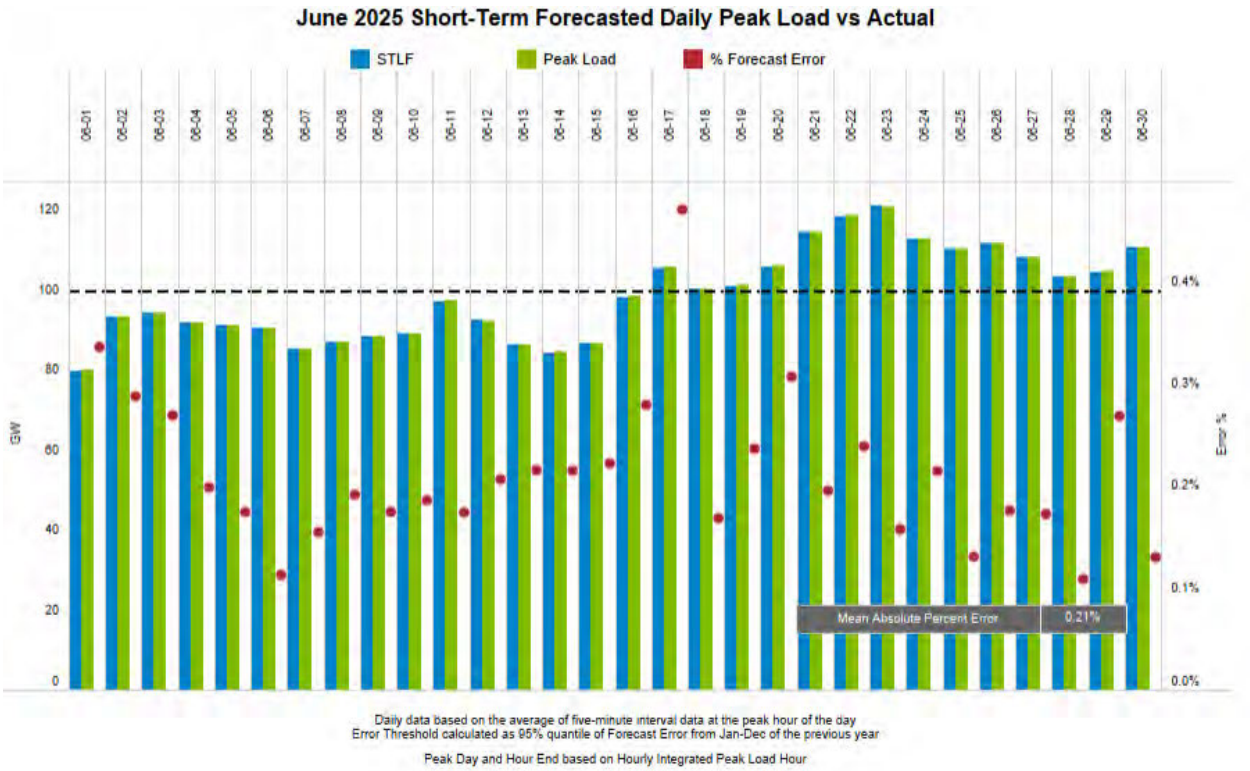
9. I was asked by Earthjustice, Sierra Club, Natural Resources Defense Council, and Environmental Defense Fund to develop an opinion on (A) whether MISO's alerts and operating conditions during June 2025 provide a factual basis for the Order's findings of a shortage of electric energy and a shortage of facilities for the generation of electricity in portions of the Midwest region of the United States; and (B) whether MISO's seasonal capacity market structure provides a factual basis for the Order's findings of a shortage of electric energy and a shortage of facilities for the generation of electricity in portions of the Midwest region of the United States.

C. Whether MISO's Alerts During June 2025 Provide a Factual Basis for the Order's Findings.

10. In my professional opinion, MISO's June 2025 operating conditions do not support DOE's claim of a shortage of electric energy or a shortage of facilities for the generation of electricity. While demand was high, it was not unprecedented compared to prior years. As I show below, demand peaked in June 2025 between 4PM and 5PM eastern on June 23, yet MISO maintained surplus resources more than ten times greater than the amount of power being supplied by Campbell. MISO has a variety of tools available during tight conditions, including flexible demand response resources that can be called on to reduce load and maintain reliability, as well as the authority to manage generators' planned outages, reschedule them if needed, and even direct generators to return from outage. As a result, MISO had sufficient tools and authority to keep the lights on, meaning that high demand, large outages, or DOE's cited alerts were not evidence of an actual shortage of electric energy.

11. During June 2025, electricity demand (i.e., "load") ranged from around 80,000 MW to close to 120,000 MW.[1] Demand reached its highest points between June 20 and June 24, and peaked at 119,300 MW between 4PM to 5PM Eastern on June 23, 2025.[2] Figure 1 shows MISO's short-term forecasts of daily peak load (in blue) and its actual daily peak loads (in green) during June 2025.

Figure 1: MISO's June 2025 Forecasted and Actual Loads



Source: MISO Monthly Operations Report: June 2025 at 25.

12. MISO has successfully dealt with higher levels of demand in recent years. In August 2024, MISO had a peak demand of 122,000 MW.[3] Similarly, as indicated in MISO's chart reproduced below as Figure 2, there were 110 hours with load greater than 100,000 MW in

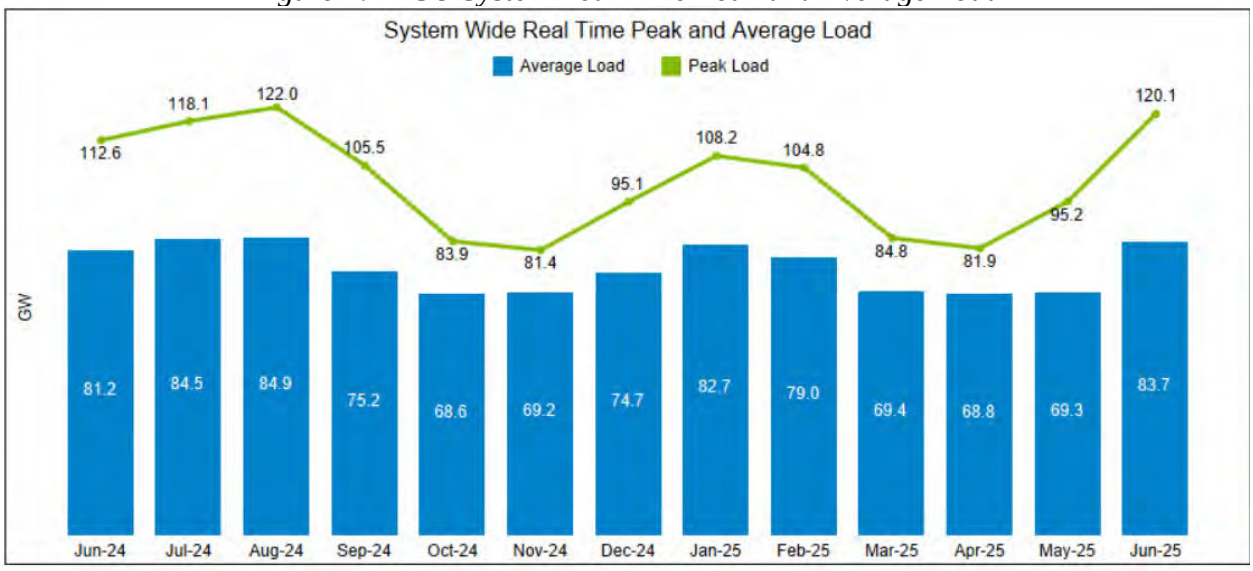
[1] MISO Monthly Operations Report: June 2025 at 25, https://cdn.misoenergy.org/202506%20Market%20and%20Operations%20Report709571.pdf.

[2] "Historical Regional Forecast and Actual Load " Report available at Market Reports, Summary folder. https://www.misoenergy.org/markets-and-operations/real-time--market-data/market-reports/#nt=.

[3] MISO Monthly Operations Report: June 2025 at 23.

June 2025 compared to 67 hours in June 2024. This means that June 2025 saw more frequent high-load conditions than the prior year, but those conditions were not unprecedented or beyond what MISO had already managed successfully.

Figure 2: MISO System Real Time Peak and Average Load



System Wide Load Weighted Temperature

	Jun-24	May-25	Jun-25
Average	77°F	63°F	76°F
Maximum	93°F	83°F	100°F
Minimum	55°F	47°F	52°F

Load Weighted Heating & Cooling Degree Days

	Average HDD	Std Dev HDD	Average CDD	Std Dev CDD
Jun-25	0.14	0.94	14.60	8.60
May-25	2.30	3.41	3.73	4.90
Jun-24	0.07	0.56	14.60	7.77

Hours with Load Greater than:

	100 GW	80 GW	60 GW
Jun-25	110	415	709
May-25	0	62	653
Jun-24	67	364	695

Source: MISO Monthly Operations Report: June 2025 at 23.

13. In order to meet demand, MISO runs markets in which generators offer their supply at various prices. MISO receives these offers shortly before the generators are to supply the power. Offered supply therefore provides a reliable and conservative indicator of available resources.

14. MISO had more than enough offered supply to meet the peak load of 119,312 MW. According to MISO data, there was 122,635 MW of offered supply.[4] That means

[4] MISO Real-Time Expanded Report with Published Date of 06/23/25. Available at MISO Market Reports – Real-Time – Real-Time Expanded Report. https://www.misoenergy.org/markets-and-operations/real-time--market-data/market-reports/#t=10&p=0&s=MarketReportPublished&sd=desc .

MISO had 3,300 MW of offered supply over and above its peak load. This is shown in the calculations below.

	Offered Supply	122,635 MW
-	Peak Load	119,312 MW
=	Surplus	3,323 MW

15. As a regular practice, MISO ensures it has more generation in reserve than needed to meet demand. It does so to cover contingencies, such as the loss of a transmission line or the loss of its largest generator. Specifically, MISO maintains operating reserves of 2,710 MW.[5] And at the peak load on June 23, MISO had more than enough resources to meet peak demand *and* maintain its operating reserve.

16. Meanwhile, MISO was not limited to only the offered supply of 122,635 MW. MISO had access to emergency headroom totaling 7,328 MW.[6] This headroom is composed of two pieces. MISO had 3,946 MW of committed emergency headroom—resources instantaneously available to MISO operators if needed—and 3,382 MW of uncommitted supply—resources available to MISO with some notice, most of which require less than 4 hours of notice. Emergency headroom (committed and uncommitted) is provided by generators that can meet the grid's needs by surpassing a limit placed for economic purposes.[7] With the emergency headroom, MISO had an even greater surplus available at the time of peak demand. Its available resources totaled 129,963 MW (122,635 MW + 3,946 MW + 3,382 MW =

[5] MISO Multiday Operating Margin Forecast Report with Published Date of 06/22/25. Available at MISO Market Reports – Summary – Multiday Operating Margin Forecast Report. https://www misoenergy.org/markets-and-operations/real-time--market-data/market-reports/#t=10&p=0&s=MarketReportPublished&sd=desc .

[6] Ibid.

[7] See Exhibit 4-11: Dispatch Limits, Page 93 of 319. Energy and Operating Reserve Markets Business Practices Manual, BPM-002-r25, Effective Date: SEP-30-2024.

129,963). That is 7,941 MW greater than the peak load plus operating reserve. The calculations are shown below.

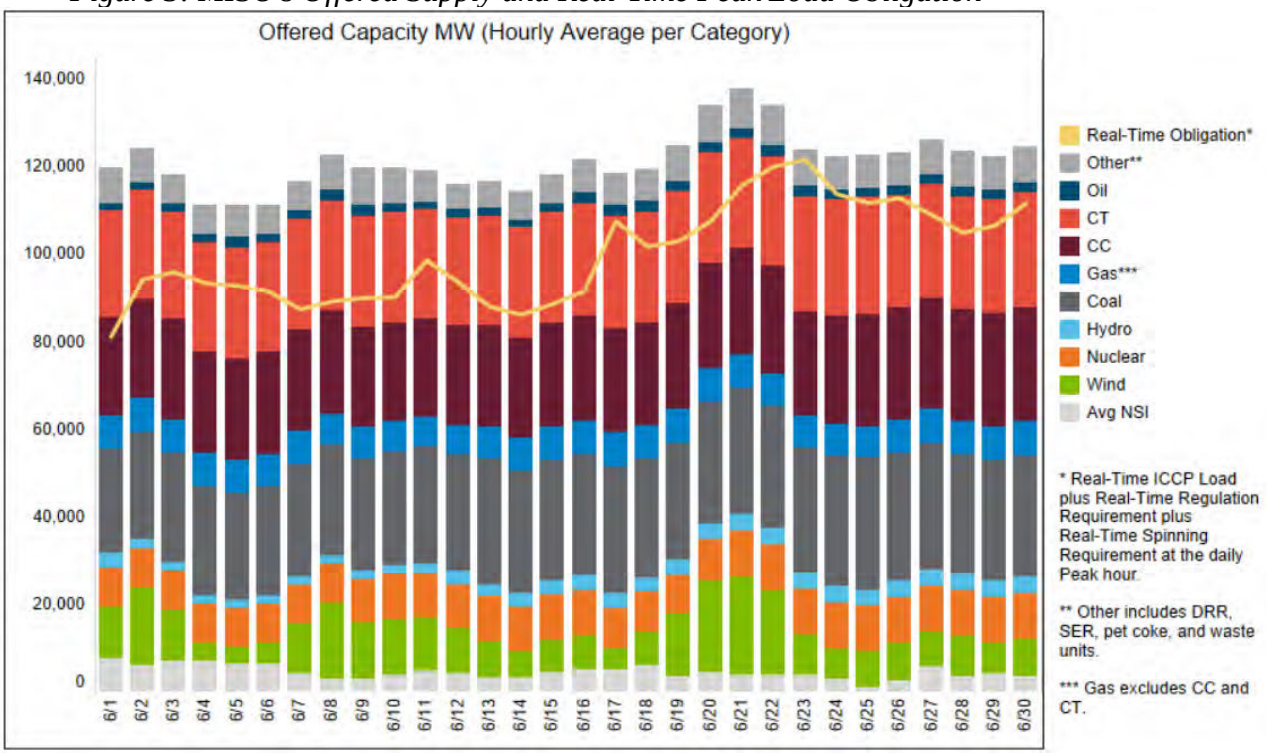
	Offered Supply	122,635 MW
+	Committed Emergency Headroom	3,946 MW
+	Uncommitted Emergency Headroom	3,382 MW
-	Peak Load	119,312 MW
-	Operating Reserve	2,710 MW
=	**Surplus**	**7,941 MW**

17. MISO's surplus of 7,941 MW was over 10 times greater than 760 MW, the amount of power Campbell was providing at the time.[8] (7,941 MW ÷ 760 MW = 10.44). Thus, at peak demand, MISO did not need Campbell to have sufficient supply to maintain reliability for the region.

18. MISO's surplus can also be presented graphically. In Figure 3 below, the vertical bars show the offered supply on each day in June at the hour of that day when demand peaked. The vertical bars *do not* include emergency headroom. On June 23, the offered supply is 122,635 MW. The yellow line shows the peak demand on each day, and does not include operating reserves. Thus, this chart gives a clear visual comparison of how much offered supply was available and whether the system had adequate offered supply to meet demand. As shown in Figure 3, even during the high-load period in June 2025, on every day in the month MISO had more supply available than it needed to meet demand. On June 23, the offered supply was 122,635 MW and peak load was 119,312 MW.

[8] EPA, Clean Air Markets Program Data (CAMPD), June hourly emissions data by unit for the Campbell Plant, available at https://campd.epa.gov/data/custom-data-download. Select "emissions" from the "data type" menu; select "hourly emissions" from the "data subtype" menu; and then select "apply." On the next screen, set 06/01/2025 as the start date and 06/30/2025 as the end date; search for and select "J H Campbell" from the "facility" menu; and then select "apply." Select "preview data."

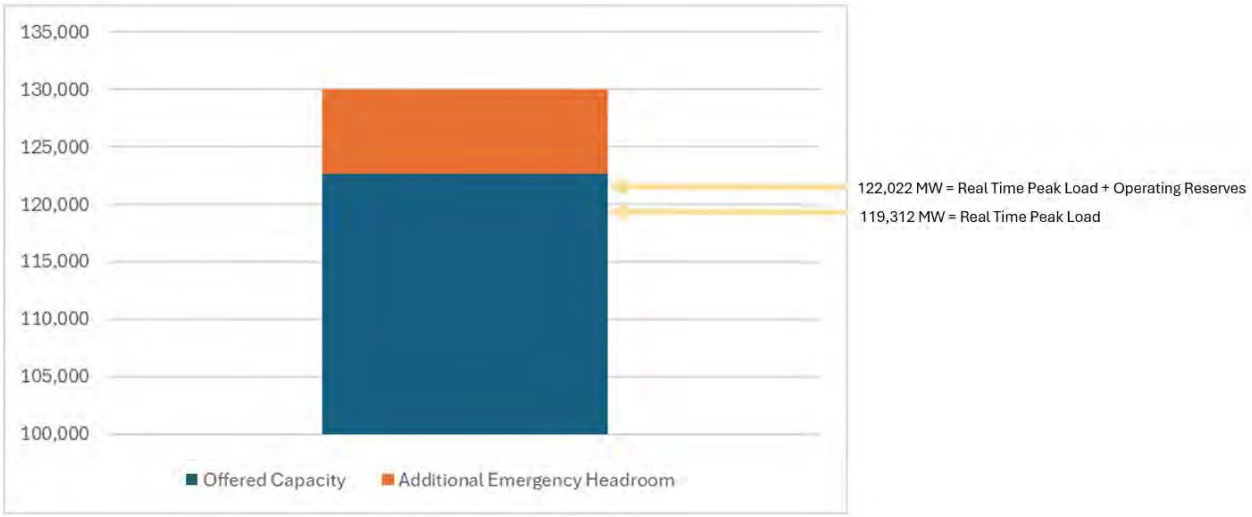
Figure 3: MISO's Offered Supply and Real-Time Peak Load Obligation



Source: MISO Monthly Operations Report: June 2025 at 33.

19. As already discussed, on top of the offered supply, MISO had another 7,328 MW of emergency headroom available to it. Thus, MISO had 129,963 MW of available resources. Additionally, to protect against contingencies, MISO keeps an operating reserve of 2,710 MW. As calculated above, MISO had surplus of 7,941 MW at the peak demand of June 23. I show this visually in Figure 4 (using the same sources indicated above).

Figure 4: Offered Supply and Emergency Headroom at Peak Load on June 23, 2025



20. It is also important to note that MISO, like other FERC-jurisdictional Regional Transmission Organizations (RTOs), has processes to manage generator outages. While generators typically submit planned outages for approval, MISO can deny or reschedule those outages if system reliability would be jeopardized.[9] In addition, MISO can request or direct a generator to return from outage sooner if conditions tighten.[10] The speed with which MISO can bring a unit back depends on how it is listed in the Outage Scheduler (e.g., "Deration" vs. "Out of Service"/"Economy") and the generator's declared recall/return-to-service time.[11] These

[9] MISO coordinates and reviews all generation outage schedules for reliability impacts. If MISO's studies show a reasonable expectation of an Emergency or other circumstances that compromise reliability, MISO may request rescheduling of planned generation outages consistent with Good Utility Practice. If voluntary rescheduling is not agreed upon, MISO has the authority to re-prioritize or reschedule the outage, and if necessary, develop Operating Guides or even revoke contributing transmission outages to maintain reliability. Source: Section 4.3. Coordination of Generation Outages, MISO Outage Operations Business Practices Manual, BPM-008-r23, Effective Date: September 1, 2024. Available at https://www misoenergy.org/legal/rules-manuals-and-agreements/business-practice-manuals/.

[10] See "4.3.3 Max Gen Event Step 1a - MISO Stakeholder Actions - 1. WHEN notified by MISO, THEN START applicable off-line AME Generation Resources." For the Generation Plant Owner. AME is Available Max Emergency. Page 22 of 41, MISO Market Capacity Emergency, SO-P-EOP-11-002 Rev: 21, Information Use Public. Available at https://cdn misoenergy.org/SO-P-EOP-11-002%20Rev%2021%20MISO%20Market%20Capacity%20Emergency683501.pdf.

[11] Page 19 of 82, MISO Outage Operations Business Practices Manual, BPM-008-r23, Effective Date: September 1, 2024.

oversight measures mean that outage levels are managed within a reliability framework, rather than being an uncontrolled signal of scarcity. Thus, even when tens of thousands of megawatts are offline, MISO still has the authority and tools to ensure enough power is available. Outages alone are not proof of shortage.

21. Notably, between 4PM to 5PM Eastern on June 23, among the resources available to MISO were 8,610 MW of demand response programs called Load Modifying Resources. This basket of resources includes traditional demand response programs that reduce peak demand by, for example, cycling air conditioning loads and using behind-the-meter generators. In essence, MISO has established a process whereby it can pay Load Modifying Resources to reduce demand. The Load Modifying Resources provide MISO with significant flexibility to address tight conditions.

22. Not all Load Modifying Resources had the same notification times – meaning that the entire 8,610 MW did not require either a 1-hour notice to reduce peak demand or a 6-hour notice. That gives MISO flexibility. MISO can first activate the resources that require longer notification times, while keeping in reserves the faster resources as conditions develop.[12] The Load Modifying Resources' notification times are shown in Figure 5.

[12] See "Due to the dynamic nature of the Bulk Electric System (BES) these preliminary declarations and instructions may be canceled prior to the actual start time of the forecasted Alert, Warning, Event or EEA as conditions warrant." Attachment 5 – Additional Information, Page 36 of 41, MISO Market Capacity Emergency, SO-P-EOP-11-002 Rev: 21, Information Use Public. Available at https://cdn.misoenergy.org/SO-P-EOP-11-002%20Rev%2021%20MISO%20Market%20Capacity%20Emergency683501.pdf. MISO's deployment of Load Modifying Resources and other Emergency Demand Response during emergencies is governed by Schedule 30 of the MISO Tariff (https://docs.misoenergy.org/miso12-legalcontent/Schedule_30_-_Emergency_Demand_Response_Initiative.pdf) and Business Practice Manual No. 26: Demand Response, BPM-026-r12, Effective Date: Nov. 7, 2024 (https://www.misoenergy.org/legal/rules-manuals-and-agreements/business-practice-manuals).

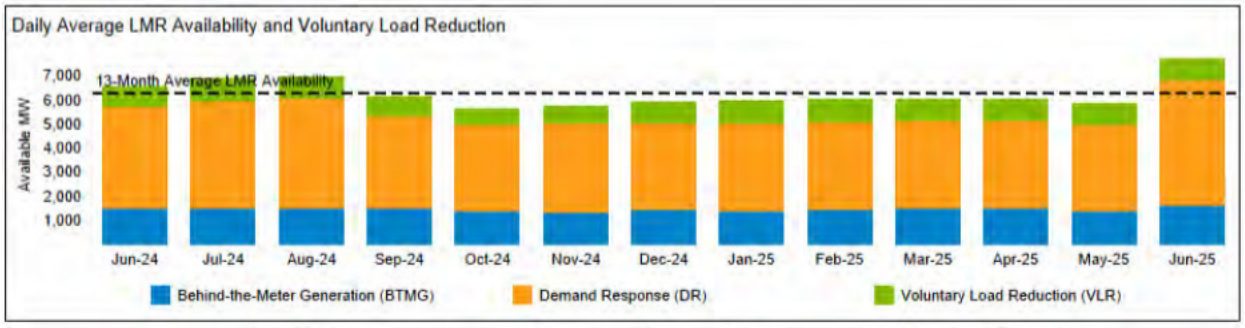
Figure 5: MISO's Available Load-Modifying Resources at Peak Load on June 23, 2025

Notification Time (Hours)	Demand Response (MW)	Behind the Meter Generation (MW)	Total
1	761	457	**1,218**
2	1,854	1,282	**3,136**
4	1,507	211	**1,718**
6	2,011	527	**2,538**
Total	**6,133**	**2,477**	**8,610**

Source: MISO Monthly Operations Report: June 2025 at 27.

23. MISO also had access to Voluntary Load Reduction, in addition to the registered Load Modifying Resources. This means that MISO had a large and flexible toolset to reduce demand during tight conditions, which helped avoid an actual shortage even during high-load days in June 2025. Figure 6 shows Load Modifying Resources and Voluntary Load Reduction available to MISO in June 2025 and for the last year.

Figure 6: Daily Average Load Modifying Resource Availability and Voluntary Load Reduction



PRA Auction	BTMG (MW)	DR (MW)	Total BTMG and DR (MW)
Summer 2024	4,144	8,109	12,253
Summer 2025	4,283	9,004	13,287

Source: MISO Monthly Operations Report: June 2025 at 27.

D. Whether MISO's Seasonal Capacity Market Structure Provides a Factual Basis for the Order's Findings.

24. In my professional opinion, MISO's transition to a seasonal capacity market structure does not provide a factual basis for DOE's claim of capacity shortages in Fall 2025. Rather, it reflects a forward-looking reform to improve the accuracy of crediting generators in

non-summer seasons, align obligations with actual seasonal risks, and protect consumers from unnecessary costs.

25. MISO's seasonal capacity market structure was primarily motivated by a drive to improve| the accuracy of generator availability, not to address generator capacity shortages. As MISO's then Senior Director for Real Time Operations and Operations Planning, Mr. Jameson Smith, explained to FERC, "when system conditions begin to get tight in the Winter, a resource may offer as available but, in reality, cannot perform when needed. The current annual Resource Adequacy construct may overstate availability throughout the year and does not properly incentivize resources to be available when most needed."[13] In other words, the seasonal capacity accreditation[14] process was designed to better align capacity credit with actual seasonal performance, ensuring that resources were credited only when they could truly deliver. DOE's reliance on the existence of this reform as proof of present shortages misconstrues its purpose: the reform was forward-looking, to enhance planning certainty, not a sign of existing scarcity.

26. The DOE Order 202-25-7 misinterpreted MISO's 2025 Planning Resource Auction results as a sign of capacity shortage.[15] In fact, as MISO's then Executive Director for Market Development and Design, Mr. Scott Wright, explained in testimony to FERC, "[h]istorically, approximately 92% of [MISO Utilities] either submitted a [Resource Plan] or

[13] Page 5-6, Jameson Smith Testimony (Nov. 30, 2021), FERC Docket No. ER22-495-000. https://elibrary ferc.gov/eLibrary/filelist?accession_number=20211130-5166.

[14] A capacity accreditation rating is how much of a generator's nameplate capacity counts toward meeting its obligations to serve load in the annual capacity auction. For example, a 100 MW unit might be credited as 90 MW, giving it a 90% capacity credit. Seasonal capacity accreditation means this value is based on a unit's demonstrated seasonal performance, rather than relying solely on summer performance year-round. For instance, a 100 MW unit might receive 90 MW of credit in summer but only 5 MW in winter due to operating limitations in colder conditions.

[15] DOE Order Page 4. https://www.energy.gov/sites/default/files/2025-08/MISO%20Order%20No.%20202-25-7.pdf.

participated by self-scheduling[16] in the [Capacity Auction]; only about 8% of [Zonal Resource Credits] have been offered economically in the [Capacity Auction]."[17] In other words, 92% of the MISO utilities that have the obligation to serve load do not meaningfully participate in the Planning Resource Auction. As Mr. Wright explains later in his testimony, MISO's seasonal capacity construct is all about MISO as a market operator sending the right price signals to generators to become available when the capacity is "tight" in the future.[18] The higher prices in the 2025 Capacity Auction, therefore, provided the intended signal without indicating a present shortage.

27. Against this backdrop, DOE further misstates the purpose of seasonality as proof of year-round shortages. In fact, when the Federal Energy Regulatory Commission approved the seasonal market structure, it emphasized that the reform aimed to improve the accuracy of capacity availability and reduce consumer costs, rather than addressing capacity scarcity. The Commission found that the seasonal capacity market structure "better align[s] resource adequacy requirements with periods of increased risks," and that it would ensure MISO utilities are not required to procure capacity beyond what is necessary in a given season.[19]

[16] Self-Scheduling is when a MISO utility commits its generation to run regardless of the market price, rather than offering it economically into the auction.

[17] Page 9, Lines 14-16. Scott Wright Testimony (Nov. 30, 2021), FERC Docket No. ER22-495-000. https://elibrary ferc.gov/eLibrary/filelist?accession_number=20211130-5166.

[18] "When capacity is **tight**, MISO's operators make reliability commitments to address the uncertainty of resource availability in place of reliance on price signals in the market." Page 19, Lines 11-13. Also, "As the resource fleet has evolved, the MISO Region has become more reliant on uncertain, uncommitted resources during **tight** operating periods." Page 22, Lines 7-8. Finally, "Such resources are accredited based on historic contributions during past system peaks, but there is no assurance that the accredited capacity will be available during **tight** grid conditions or a particular emergency event." Page 23, Lines 9-12. Scott Wright Testimony.

[19] "Further, by providing a more granular assessment of seasonal resource adequacy needs, MISO's proposal will ensure that LSEs are not required to procure capacity beyond what is necessary to ensure resource adequacy in a given Season." Paragraph 77, Order Accepting Proposed Tariff Revisions Subject to Revision re Midcontinent Independent System Operator, Inc. (Aug. 31, 2022) under FERC Docket No. ER22-495-000. https://elibrary ferc.gov/eLibrary/filelist?accession_number=20220831-3093.

28. As MISO explained to FERC, "its models indicate that the move to seasonal Auctions will result in nearly double the amount of uncleared [Zonal Resource Credits[20]] in non-Summer Seasons, providing liquidity to the market for replacement capacity."[21] In plain terms, the seasonal framework creates more available capacity (i.e., Zonal Resource Credits) that utilities can procure if one of their designated resources becomes unavailable, ensuring that the seasonal capacity market structure expands supply options rather than signaling a shortage.

29. Likewise, the Commission highlighted that "MISO has demonstrated that its proposal will result in lower Reserve Requirements for non-Summer Seasons, at the MISO-wide level, which should in and of itself reduce costs to customers."[22] MISO's seasonal capacity market structure is thus a refinement to improve risk alignment and consumer protection, not evidence that MISO lacks sufficient resources outside the summer peak.

I declare under penalty of perjury under the laws of the United States, pursuant to 28 U.S.C. § 1746, that the foregoing is true and correct to the best of my knowledge.

Executed on this 3rd day of September 2025, in Roseville, Minnesota.

Rao Konidena

Rao Konidena
Rakon Energy LLC
2309 Auerbach St, Roseville, MN 55113

[20] Zonal Resource Credits (ZRCs) can be traded between utilities and other MISO market participants. For example, if a utility holds surplus ZRCs beyond what it needs to meet its load-serving obligations, it can sell or transfer those ZRCs to another entity that is deficient.

[21] "It is reasonable to expect that bilateral trading for replacement capacity will be much more robust under the proposal than it is today. Additionally, the move to seasonal auctions with seasonal PRMR targets based on seasonal peaks has been modeled to result in nearly double the amounts of uncleared ZRCs outside the summer Season, providing liquidity to the market for replacement capacity." Page 28, MISO Deficiency Letter Response (Apr. 8, 2022) under Docket No. ER22-495-000. https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20220408-5195 Note that "Replacement capacity" is the additional capacity a MISO utility must procure to meet its load obligation when a designated resource cannot provide its committed Zonal Resource Credits (ZRCs), such as when a generating unit is on outage, derated, or otherwise unavailable.

[22] Paragraph 88, Order Accepting Proposed Tariff Revisions Subject to Revision re Midcontinent Independent System Operator, Inc. under ER22-495.

Attachment A

RAO KONIDENA

ENERGY MARKET EXPERTISE IN DISTRIBUTED ENERGY RESOURCES

Roseville, MN 55113 Cell: 612-594-9257 · rkonidena76@gmail.com

Rao Konidena brings deep experience in distribution system planning and integration of distributed energy resources. His regulatory testimonies across the U.S. have informed utility distribution planning, storage deployment strategies, and DER tariff design. At MISO, Rao led studies on demand-side potential and DER impacts on long-term planning. His consulting work spans utility-scale and customer-sited solutions, with a consistent focus on how DERs shape the future of distribution systems.

Rao is on the Board of Ever Green Energy and President of the Board at the Center for Renewables Integration.

EXPERIENCE

RAKON ENERGY® LLC, Roseville, MN
President & Chief Executive Officer (CEO) May 2018 – Present

Testimonies filed before state regulatory agencies and related work.

- The Colorado Office of the Utility Consumer Advocate engaged Rakon Energy LLC to provide expert testimony before the Colorado Public Utilities Commission on a utility distribution system plan. Proceeding No. 24A-0547E Public Utilities Commission

- Engleman Fallon, PLLC engaged Rakon Energy LLC to provide expert testimony before the Federal Energy Regulatory Commission on behalf of the Kentucky Public Service Commission regarding a transmission cost allocation complaint. FERC Docket No. EL25-67-000. eLibrary | File List

- Citizens Utility Board and Environmental Defense Fund engaged Rakon Energy to provide testimony before the Illinois Commerce Commission (Docket No. 24-0088) in the Ameren Transmission Company of Illinois and Ameren Illinois Company d/b/a Ameren Illinois in the Joint Petition for a Certificate of Public Convenience and Necessity proceeding. https://icc.illinois.gov/docket/P2024-0088/documents/356793

- San Louis Obispo Mothers For Peace engaged Rakon Energy in the Application of Pacific Gas and Electric Company to Recover in Customer Rates the Costs to Support Extended Operation of Diablo Canyon Power Plant from September 1, 2023 through December 31, 2025 and for Approval of Planned Expenditure of 2025 Volumetric Performance Fees (U 39 E) docket before the California Public Utilities Commission Proceeding A.24-03-018. https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2403018/7629/537498256.pdf

- The Massachusetts Attorney General's Office, Office of Ratepayer Advocacy, engaged the Center for Renewables Integration to provide expert testimony before the Massachusetts Department of Public Utilities regarding Eversource (DPU 23-126), National Grid (DPU 23-115) and Unitil's (DPU 23-117) Energy Storage Tariffs. Rakon Energy is part of the Center for Renewables Integration expert witness team. https://eeaonline.eea.state ma.us/DPU/Fileroom/dockets/bynumber

- The Commonwealth of Pennsylvania's Office of Consumer Advocate engaged Rakon Energy LLC to provide expert testimony before the Pennsylvania Public Utilities Commission on a utility rate case. Docket No. R-2024-3047068 https://www.puc.pa.gov/pcdocs/1835234.pdf

- Rakon Energy is engaged on behalf of the Environmental Law & Policy Center and the Citizens Utility Board to provide testimony before the Illinois Commerce Commission (Docket No. P2023-0658) in the Ameren Illinois Company d/b/a Ameren Illinois and Ameren Transmission Company of Illinois - Joint Petition for a Certificate of Public Convenience and Necessity proceeding. https://icc.illinois.gov/docket/P2023-0658/documents/349330

- Rakon Energy is engaged by NC WARN, a nonprofit organization, for testimony before the North Carolina Utilities

Commission (Docket No. E-100, SUB 190) in Duke Energy Carolina Biennial Consolidated Carbon Plan and Integrated Resource Plan.
https://starw1.ncuc.gov/NCUC/ViewFile.aspx?Id=34aaef8f-5012-48aa-b319-77861e016436

- Rakon Energy was engaged by NC WARN, a nonprofit organization, for testimony before the North Carolina Utilities Commission (Docket No. E-7, SUB 1276) in Duke Energy Carolina Rate Case.
https://starw1.ncuc.gov/NCUC/ViewFile.aspx?Id=eff4d6f7-4a43-4c25-8784-2f5718375204

- The Office of People's Counsel in State of Maryland engaged Rakon Energy LLC to provide expert testimony before the Maryland Public Service Commission on a transmission line rebuild project. PSC Case No: 9698. Submitted date – September 13, 2023. https://webpsc.psc.state.md.us/DMS/case/9698

- San Louis Obispo Mothers For Peace engaged Rakon Energy in the Proposed Extension of the Diablo Canyon Power Plant docket before the California Public Utilities Commission Proceeding R.23-01-007.
https://mothersforpeace.org/wp-content/uploads/2023/07/Rao-Konidena-Testimony_Final.1.pdf

- Voltus, an aggregator, engaged Rakon Energy to provide expert testimony before the Minnesota Public Utilities Commission – Docket No. E999/CI-22-600 (Aggregator of Retail Customers), and Kansas Corporation Commission – Docket No. 23-EKCE-588-TAR (Demand Response Aggregator).
https://www.edockets.state mn.us/edockets/searchDocuments.do?method=showPoup&documentId={509C6C87-0000-C610-A629-18F8958B5C38}&documentTitle=20234-194648-01

  https://estar.kcc ks.gov/estar/ViewFile.aspx/S202307071819321214.pdf?Id=01c14579-4f44-42e7-887a-14381b43b514

- The Commonwealth of Pennsylvania's Office of Consumer Advocate engaged Rakon Energy LLC to provide expert testimony before the Pennsylvania Public Utilities Commission on a transmission line rebuild project. Docket No. A-2022-3037374. Starting on Page 198, https://www.puc.pa.gov/pcdocs/1797979.pdf

- The Commonwealth of Pennsylvania's Office of Consumer Advocate engaged Rakon Energy LLC to support OCA's response to the questions posed by the Pennsylvania Public Utility Commission's Secretary in the policy proceeding - Utilization of Storage Resources as Electric Distribution Assets. Docket No. M-2020-3022877. Starting on Page 18, https://www.puc.pa.gov/pcdocs/1726077.pdf

- A prominent solar advocacy group – Vote Solar, engaged Rao for expert testimony work in Nevada and Minnesota IOUs IRP filing. The docket # for Minnesota PUC is Docket No. E002/RP-19-368 and the docket #s for Public Utilities Commission of Nevada PUC are Docket Nos. 21-06001 and 21-06002.

  For Nevada testimony,
https://ecms.nv.gov/puc/api/Document/ATczlezYGwl0gYI%C3%81kEPTWEapPcfzukJf8jLWbk0n4gatA%C3%81WwN8OhaGK%C3%81Y%C3%89J4njfgfyQKShz62MTaictAWaf3PsA%3D/?OverlayMode=View

  For Minnesota PUC testimony - Starting Page 110, https://votesolar.org/wp-content/uploads/2021/02/XcelMNIRP2021.pdf

- He has provided expert testimony support for Environmental Law and Policy Center (ELPC) at the Public Service Commission of Wisconsin (PSCW) on the MISO Multi-Value Project (MVP) line in Wisconsin. Docket No. 5-CE-146. https://apps.psc.wi.gov/ERF/ERFview/viewdoc.aspx?docid=365126

- He provided affidavit support for the Office of the People's Counsel of the District of Columbia (OPC-DC) at the Federal Energy Regulatory Commission (FERC) on PJM's Reserves Pricing Proposal and municipal utilities in Wisconsin and Missouri at FERC on MISO's Resource Adequacy construct. Starting Page 177,
https://edocket.dcpsc.org/apis/api/filing/download?attachId=100991&guidFileName=ae06faca-5aa9-43f2-aea4-dc5457ab7adb.pdf

- Rao also submitted an affidavit before FERC on behalf of Missouri Joint Municipal Electric Utilities Commission, Missouri River Energy Services, and WPPI Energy regarding the Midcontinent Independent System Operator's (MISO) External Resource Zone proposal. Docket No. ER18-1173-001.
https://elibrary ferc.gov/eLibrary/filelist?accession_number=20180626-5242&optimized=false

Providing consulting services related to Federal and state energy policies, focusing on energy storage and distributed energy resources.

- Rakon Energy, as part of the Center for Renewables Integration team, is supporting a renewable energy developer to look at the MISO and PJM generator interconnection queue for solar/storage site evaluation.
- Rakon Energy is supporting a solar developer to evaluate distributed energy and battery energy storage system (BESS) development opportunities in MISO.
- Rakon Energy supported a Community Solar Garden developer with MISO's DER Affected Systems Study process.
- Rakon Energy is engaged as a Battery Energy Storage System consultant to the Georgia Public Service Commission.
- An Independent Power Producer engaged Rakon's services to understand MISO's seasonal resource adequacy construct and its impact on Power Purchase Agreement negotiations with a MISO utility.
- A renewable energy developer engaged Rakon Energy to provide MISO expertise for their renewable energy project portfolio in various stages and study cycles of the Generator Interconnection Queue and the capacity credit impact from MISO's seasonal capacity construct.
- An aggregator engaged Rakon Energy as part of the team to represent their interests at RTO stakeholder committees on FERC Order 2222.
- Advanced Energy Economy and the Natural Resources Defense Council's Sustainable FERC Project engaged Rakon to monitor MISO's FERC Order 2222 implementation process.
- Rakon Energy was part of the team engaged by a technology company to represent their interests at the PJM RTO. Another similar company hired Rao to navigate MISO's market rules for data center interconnection.
- Rakon Energy provides generic electrical engineering expertise for the Commonwealth of Pennsylvania's Office of Consumer Advocate in the transmission, distribution services and miscellaneous electric issues.
- He provided training as part of the Tuatara team on DERs to Colombia's grid operator XM and the ESTA International team on energy storage benefits to Mexican regulator CRE.
- He provided advocacy support for Energy Storage Association (ESA) at MISO on FERC Order 841 Compliance.

Advisor, Volunteer, Pro-Bono assignments

- Rao presented on US Energy Markets, Capacity Markets and Retail Energy Markets to Independent Electricity Market Operator Philippines (IEMOP) and other stakeholders, as part of a workshop organized by the United States Energy Agency (USEA).
- Rao presented on Distributed Energy Resources (DER) and peer-reviewed Demand Side Management and DER plans for Central American regulators, as part of NARUC International Peer Review.
- Rao presented and shared best practices around the impact of provisioning ancillary services. At an Eastern Africa regional workshop organized by the United States Energy Agency (USEA), the United States Agency for International Development (USAID) and the Power Africa initiative.

MIDCONTINENT INDEPENDENT SYSTEM OPERATOR (MISO), Eagan, MN
Principal Advisor, Policy Studies Aug 2015 – May 2018

- Recognized as an expert on all thing's energy storage and distributed energy resources from an economic transmission planning perspective
- Project manager for long term independent load forecast and demand response/energy efficiency/distributed generation potential study.
- MISO representative on Department of Energy (DOE) US DRIVE Grid Interaction Technical Team

Senior Manager, Transmission Asset Management Operations Feb 2013 – July 2015

- He engaged the division lead in the development of strategic initiatives and operating plans.
- Rao chaired the Economic Modeling Framework Working Group of international Grid operators GO-15.

Manager, Resource Forecasting (started at Engineer II) Sep 2003 – Jan 2013

- ***Main Accomplishments***
  - In this role, I directed the Demand Response & Energy Efficiency potential study for MISO, with the support of Global Energy Partners consultants.
  - Directed the MISO Energy Storage Study identifying the economic potential for grid-scale energy storage in MISO footprint, providing strategic consulting services to investor-owned utilities, public power utilities, asset owners, and investors.
- ***Regulatory Experience***
  - Responsible for analytical assessments that meet MISO's Federal Energy regulatory compliance obligations as well

as our Transmission Owners (e.g., FERC Market-based rates).
- Responsible for supporting state regulators and MISO Board of Directors with technical analysis related to policy drivers.

PWRSOLUTIONS, Inc., Dallas, TX (Consulting) May 2001 – August 2003
Student Intern and Electrical Engineer
- Rao executed generator interconnection studies for Independent Power Producers (IPPs) clients.
- Analyzed future generator and transmission needs in the Eastern Interconnection.

EDUCATION

THE UNIVERSITY OF MINNESOTA, Minneapolis, Minnesota
Carlson School of Management
Master of Business Administration, Global Executive Program May 2011
Emphases: Strategic Management, International Business

- Responsible for all financial aspects of marketing mobile charging services for Electric vehicles in the Singapore market.

UNIVERSITY OF TEXAS AT ARLINGTON, Arlington, Texas
Energy Systems Research Center (ESRC)
Master of Science in **Electrical Engineering** May 2002

- Master's Thesis in Economic Analysis of Distributed Generation (Photovoltaics (P.V.) and Fuel Cells)

BLOG POSTING, PUBLICATIONS & PRESENTATIONS

1. Co-Author for a graduate level textbook titled "Modern Electricity Systems: Engineering, Operations, and Policy to address Human and Environmental Needs". Release date - August 2022 with Wiley.
2. **He has authored multiple publications in Electricity Journal, Renewable Energy World (blog), and other peer-reviewed industry journals.**

BOARD & VOLUNTEER ACTIVITIES

- Board of Directors, Ever Green Energy. Sep 2019 – present
- President, Board of Directors, Center for Renewables Integration. Dec 2023 - present.