BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)
Emergency Order: Midcontinent	)
Independent System Operator	)
(MISO)	)
	)

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	)
(MISO)	)
	)

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

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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



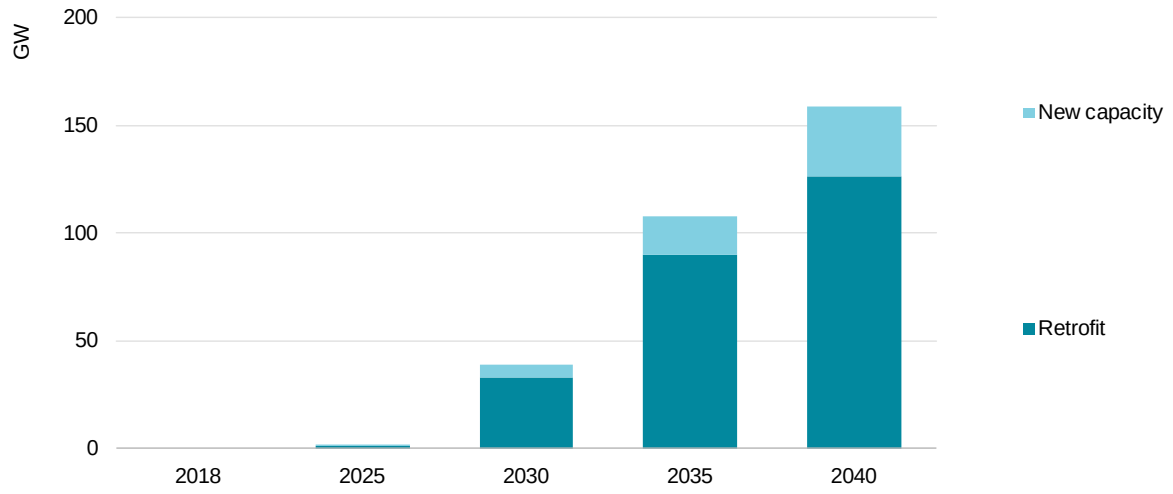
International Energy Agency

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

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

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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.

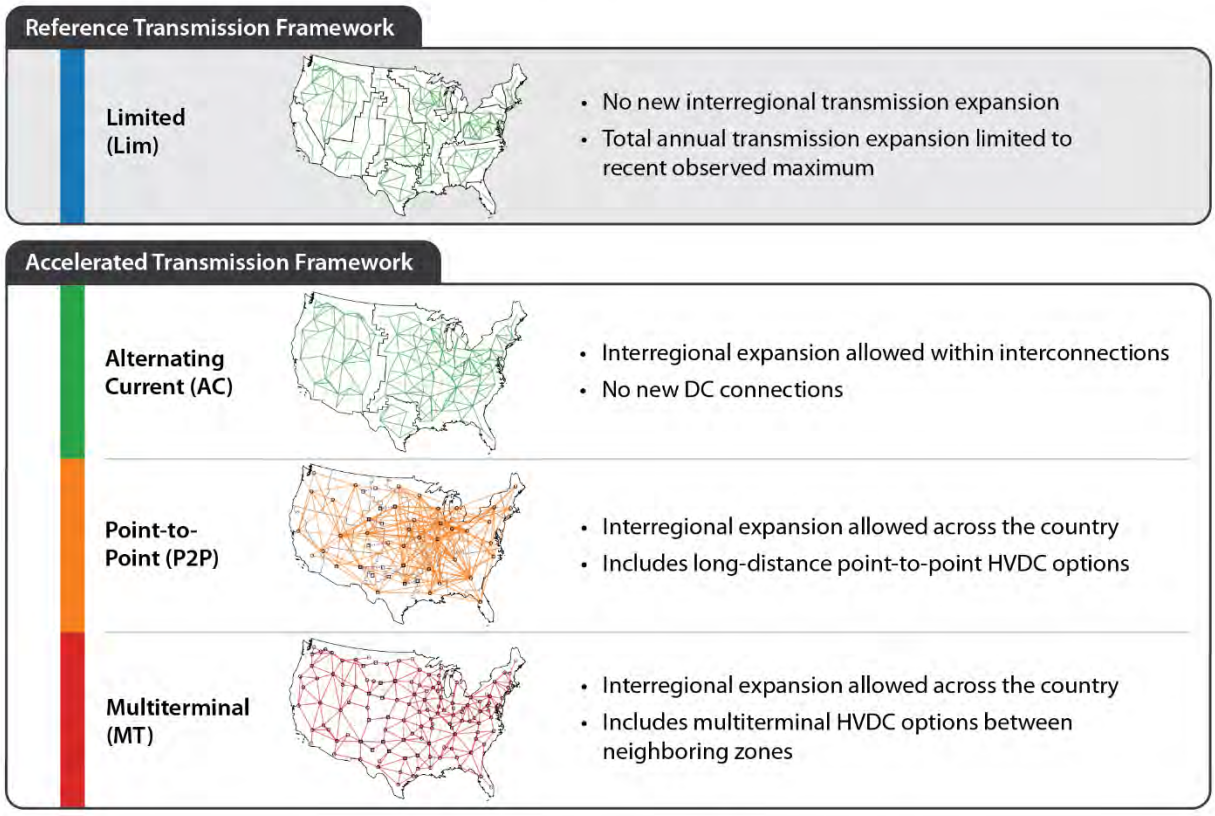

Figure I. NTP Study transmission frameworks

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.

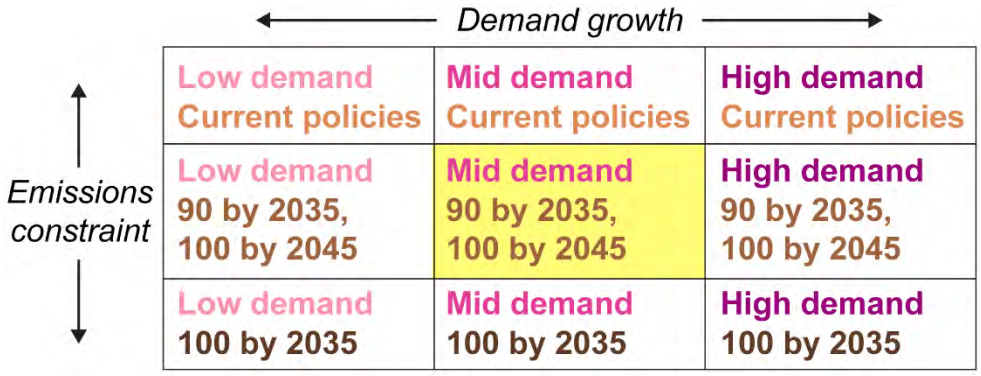

Figure II. Core demand and emissions assumptions.

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]

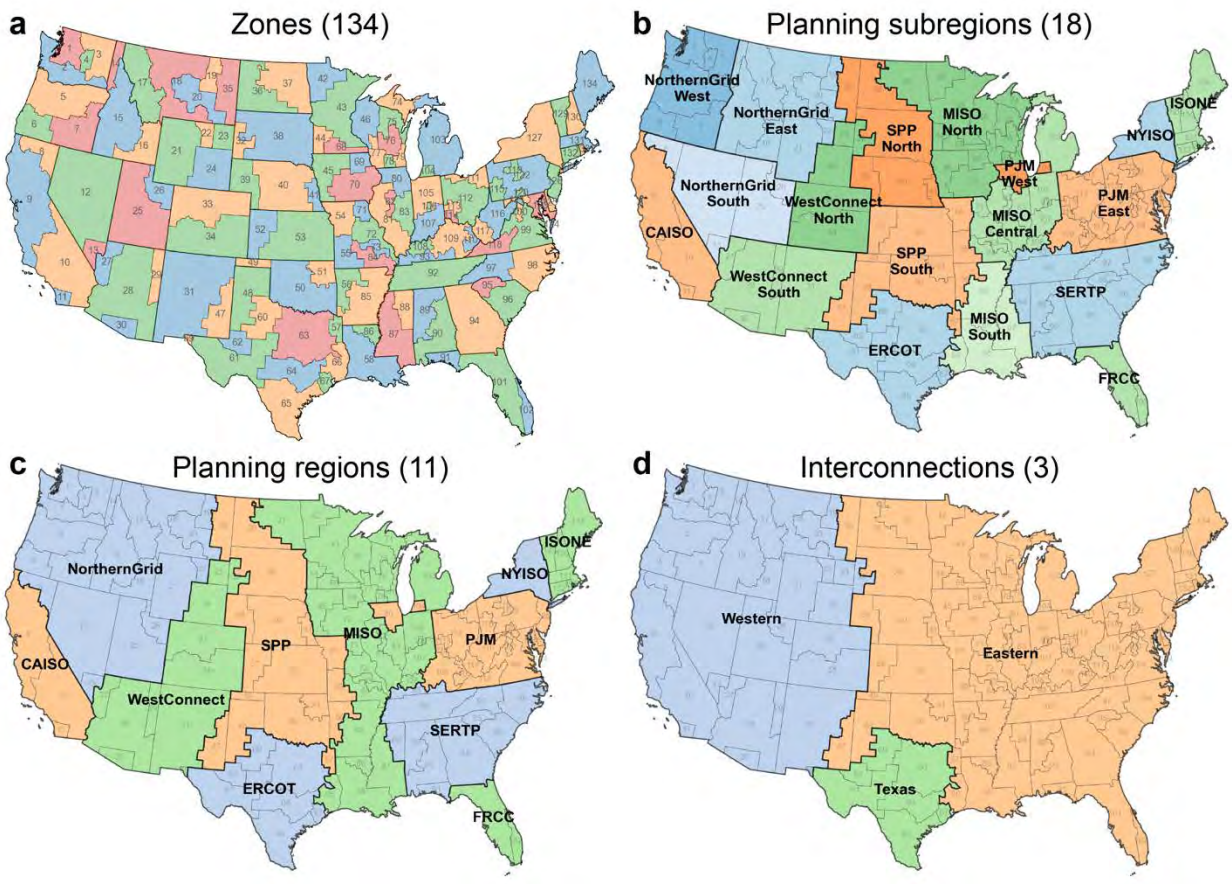


Figure 1. Hierarchy of regions used in the ReEDS model

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.

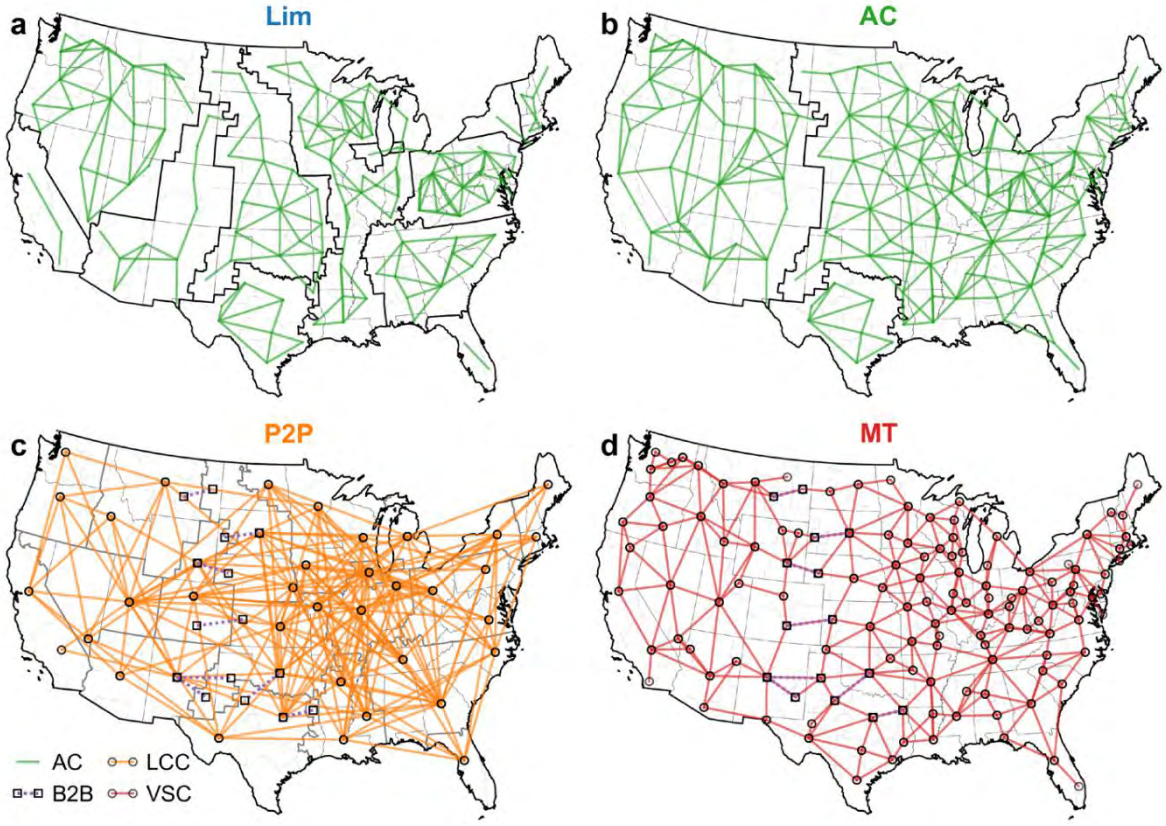


Figure 2. Expandable transmission interfaces in the four transmission frameworks considered in this study

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.

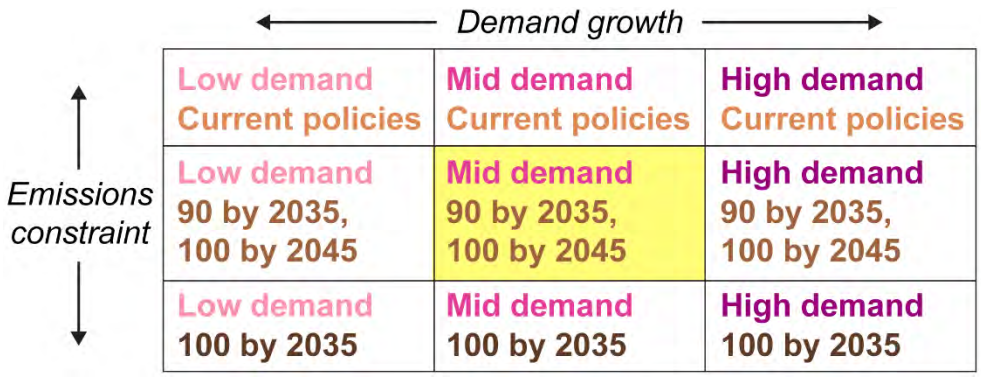


Figure 3. Core demand and emissions assumptions

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).

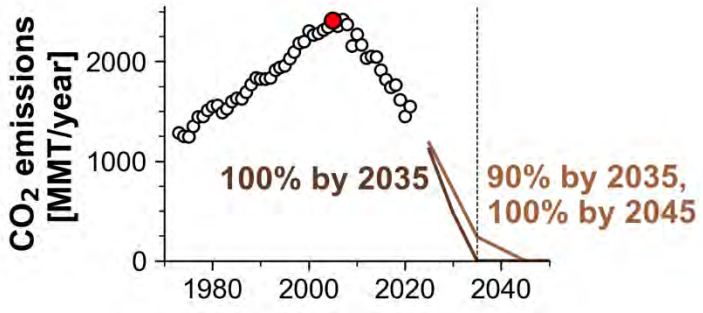


Figure 4. Emissions constraints under grid decarbonization scenarios

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.

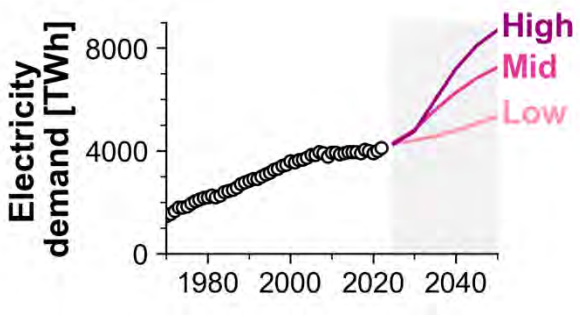


Figure 5. Annual demand assumptions for the contiguous United States

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.

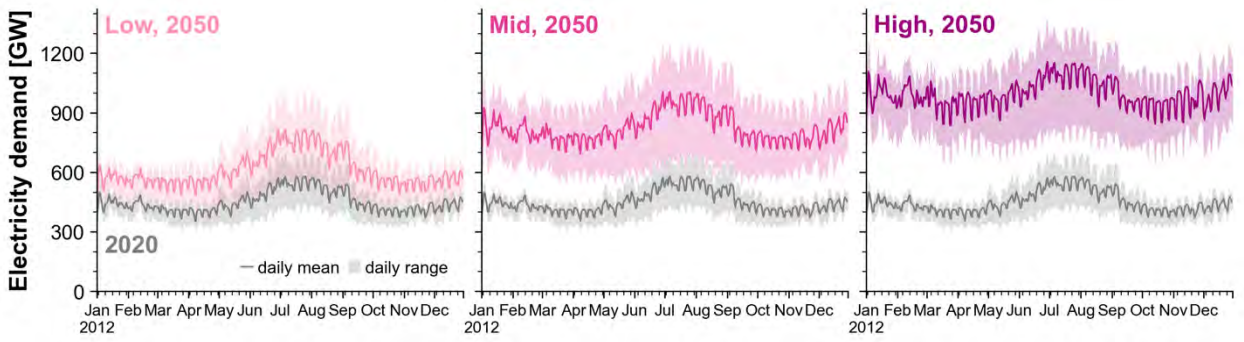


Figure 6. Daily demand profiles for the contiguous United States in 2020 and 2050

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.

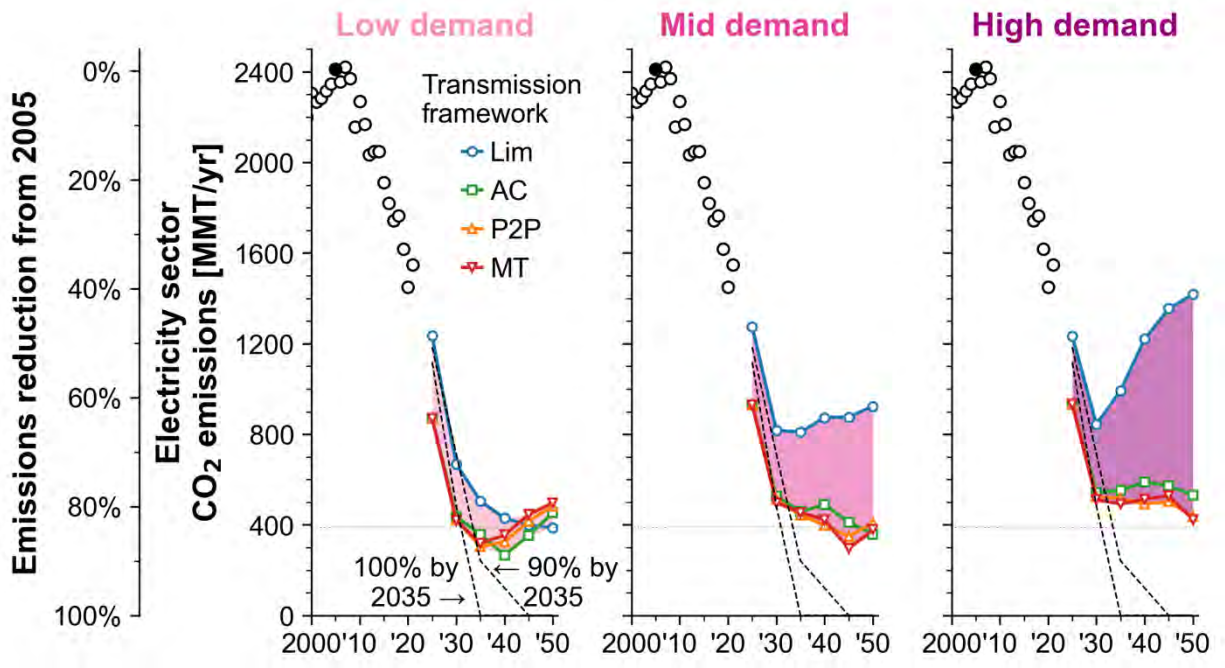


Figure 7. Electricity sector CO_2 emissions under current policies across demand assumptions

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.

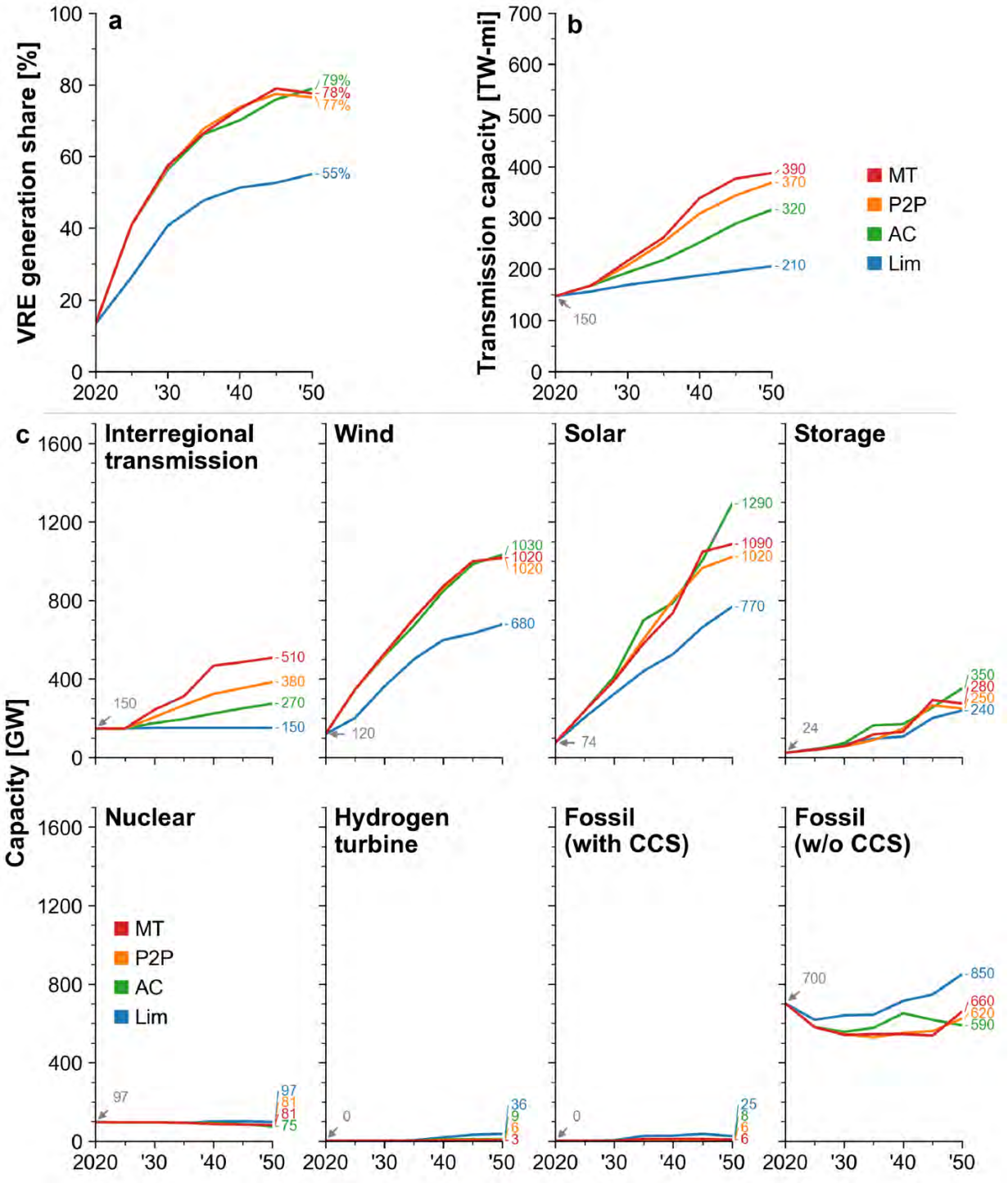


Figure 8. Trajectories of VRE share (a), transmission capacity (b), and nameplate capacity (c) under mid demand and current policies

"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.

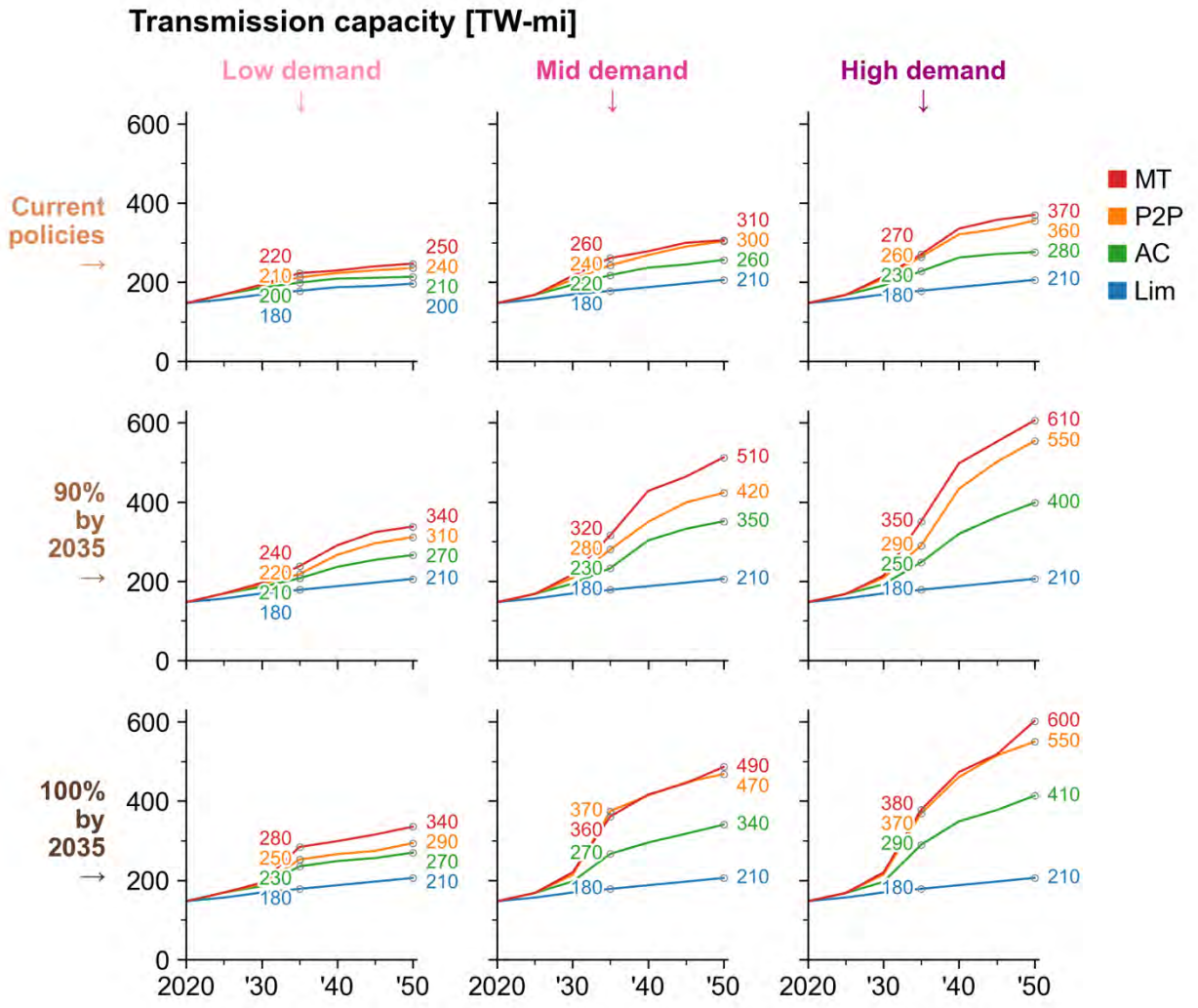


Figure 9. Total transmission capacity as a function of demand (columns) and emissions constraint (rows)

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).

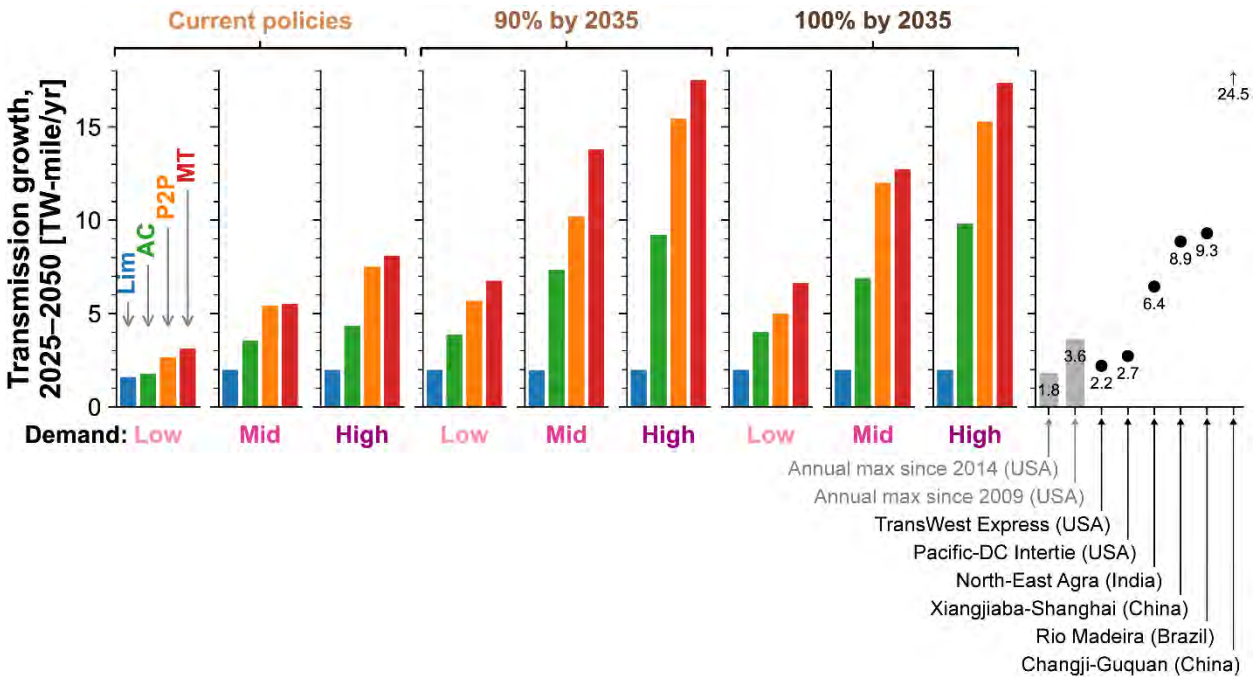


Figure 10. Total transmission growth rate in TW-miles/year as a function of demand, emissions constraint, and transmission framework

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.

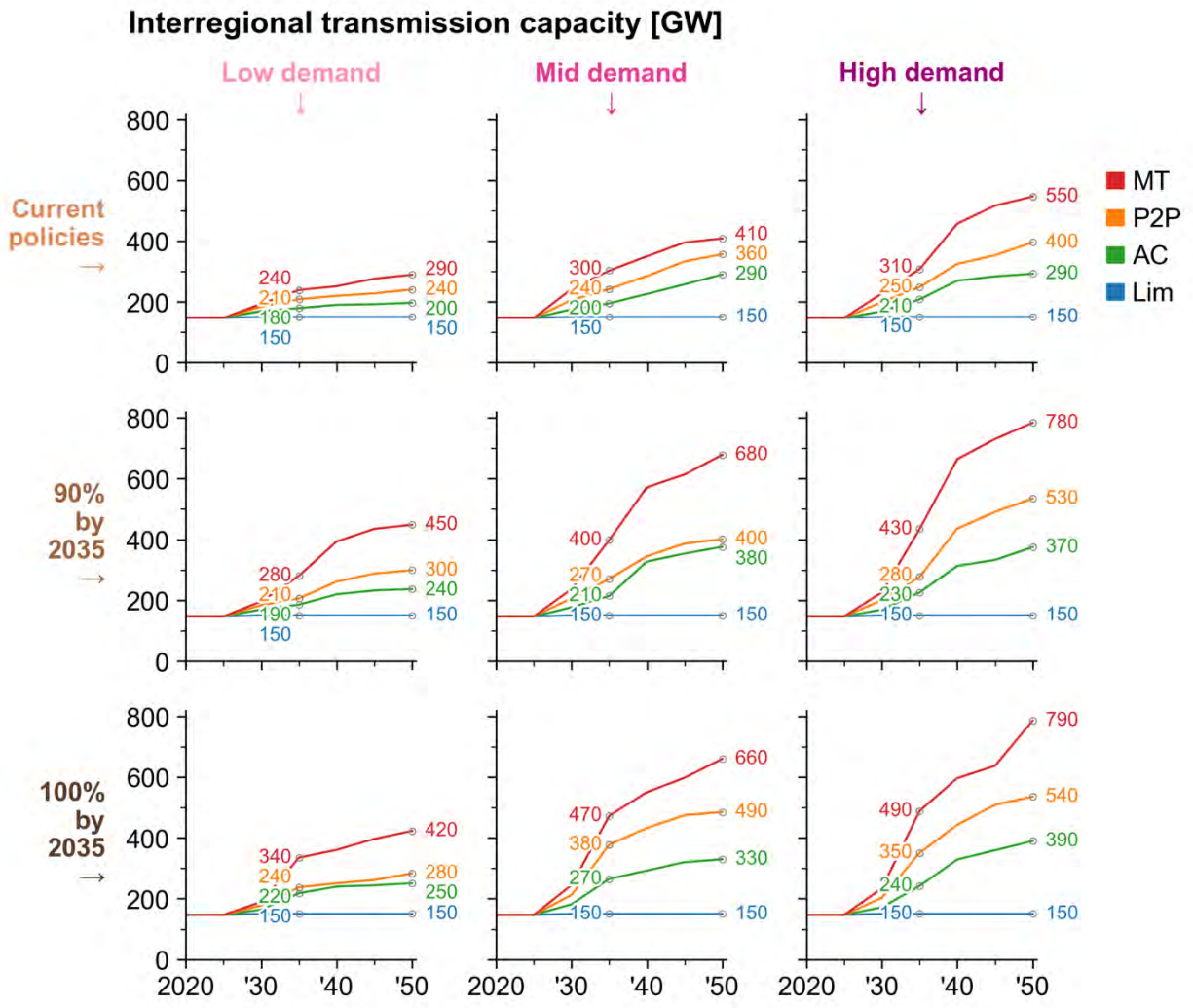


Figure 11. Interregional transmission capacity as a function of demand (columns) and emissions constraint (rows)

"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).

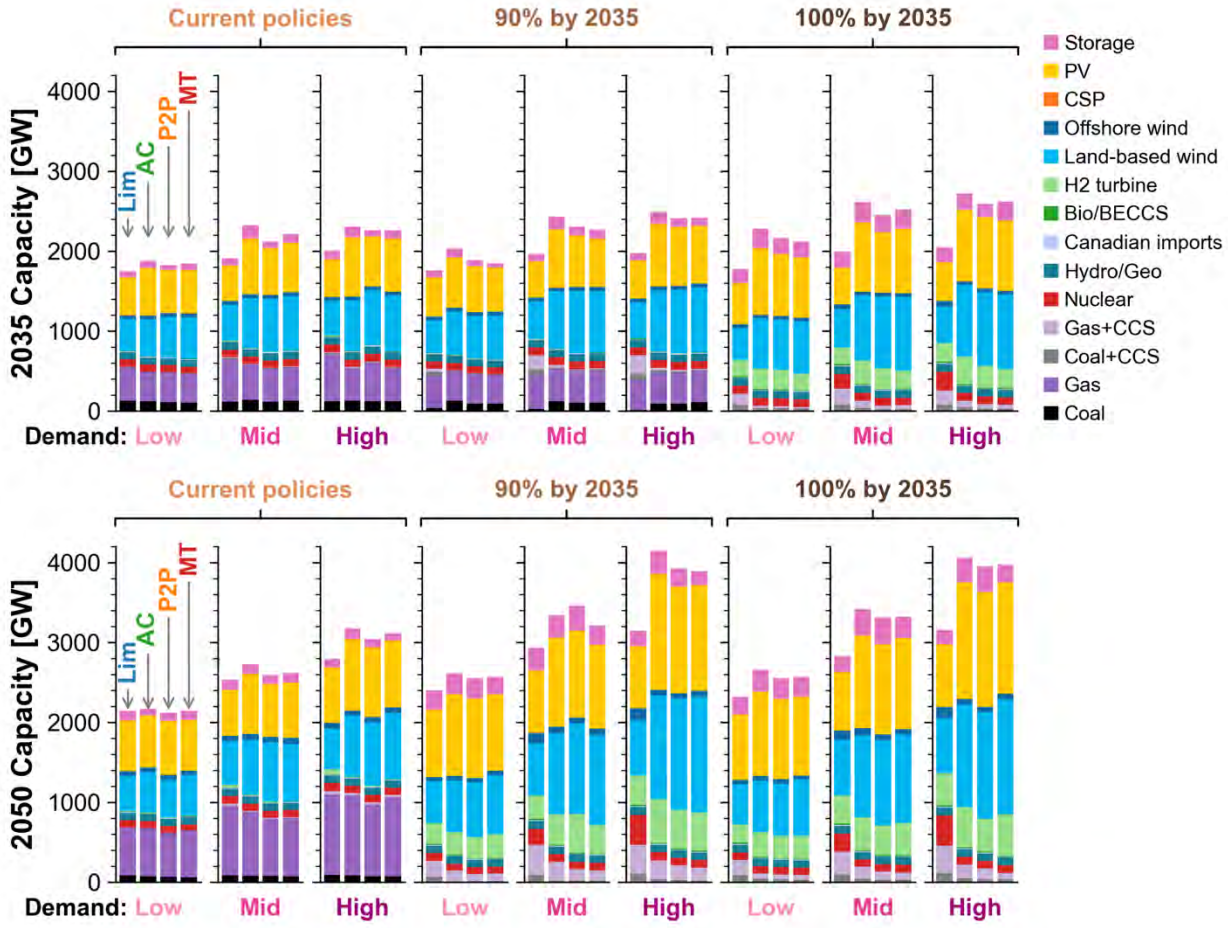


Figure 12. Generation capacity in 2035 and 2050 as a function of demand, emissions constraint, and transmission framework

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).

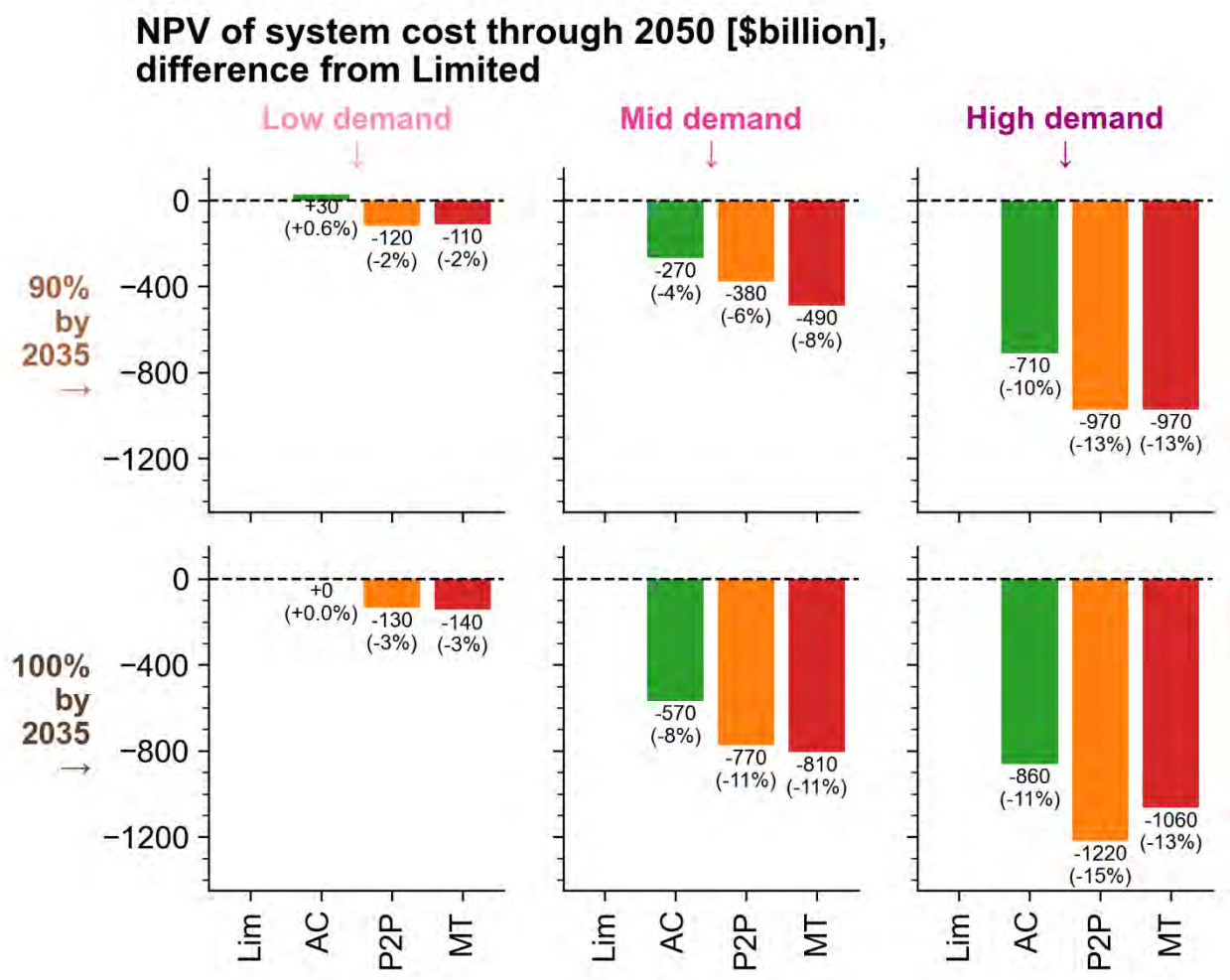


Figure 13. Net present value of total system cost through 2050 expressed as savings relative to the Limited framework

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.

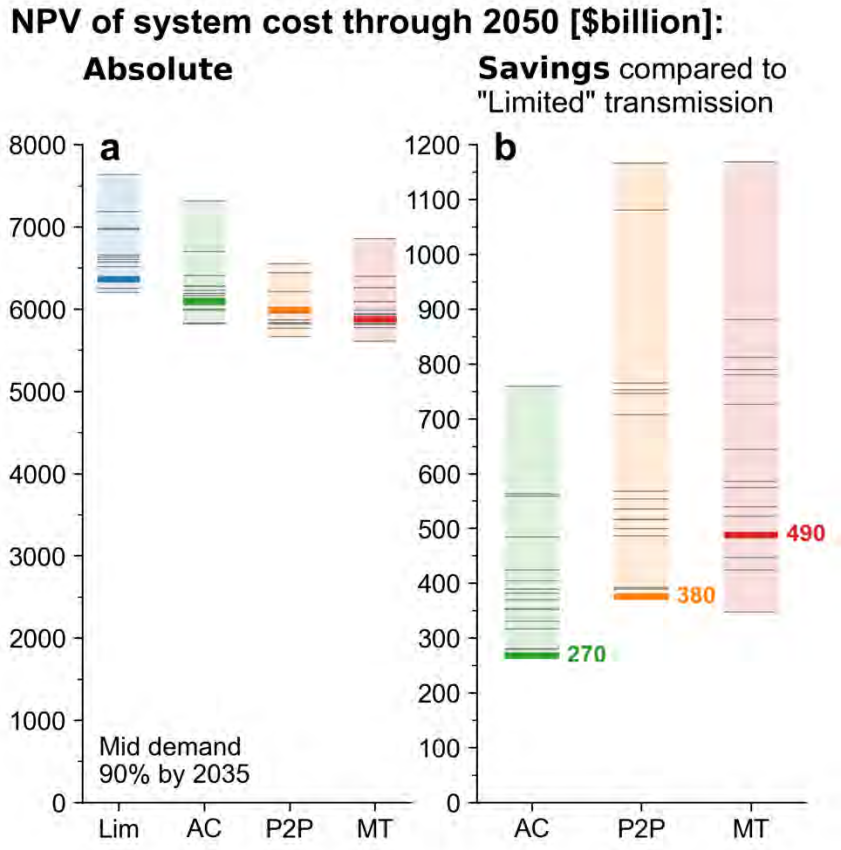


Figure 14. Net present value of total system cost through 2050 under central (Mid-Demand 90% by 2035) assumptions expressed in absolute terms (a) and as savings relative to the Limited framework (b)

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

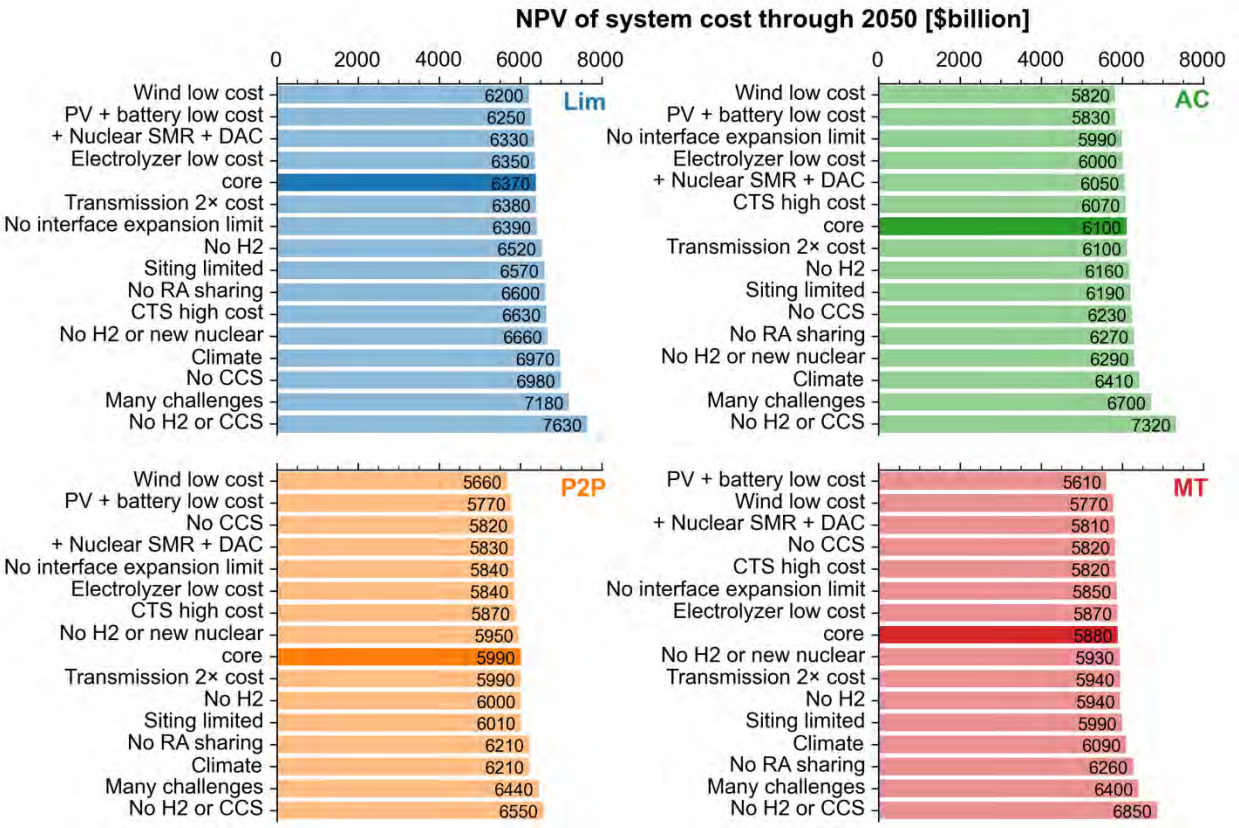


Figure 15. Net present value of total system cost through 2050 for each transmission framework and sensitivity case under Mid-Demand 90% by 2035 assumptions

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.

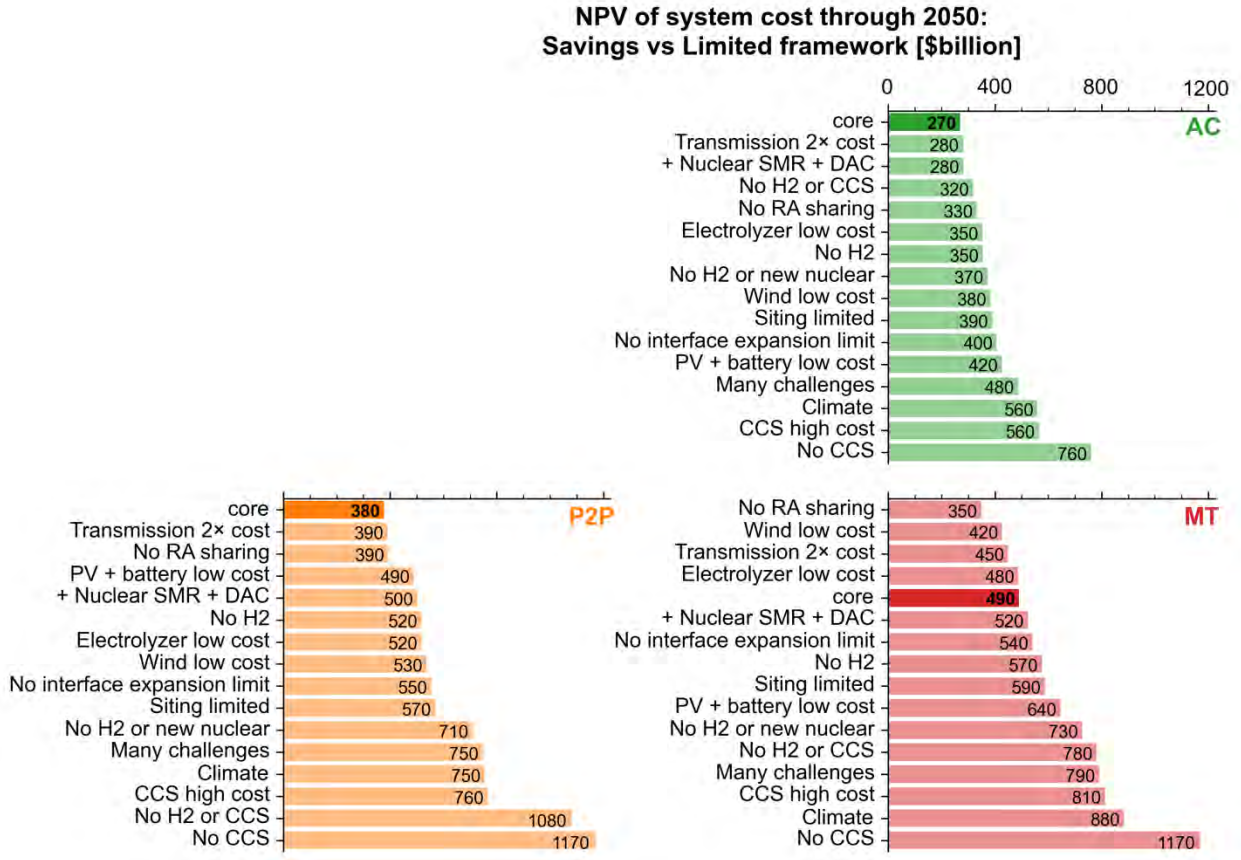


Figure 16. Net present value of total system cost savings relative to the Limited framework under Mid-Demand 90% by 2035 assumptions

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.

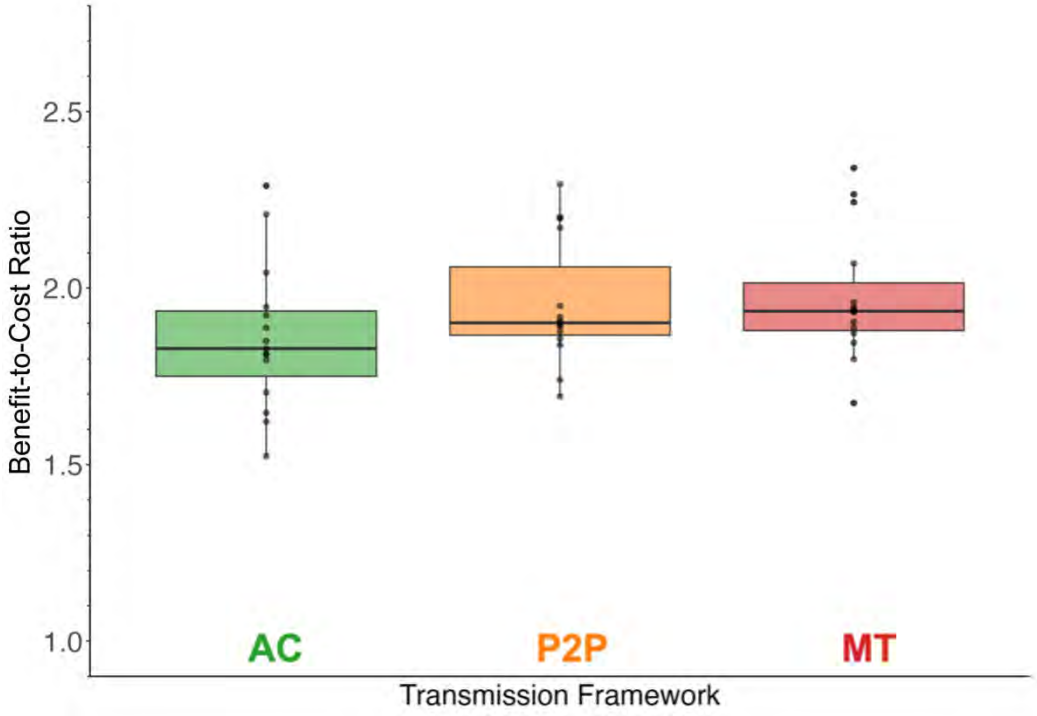


Figure 17. Benefit-to-cost ratio of systemwide savings compared to additional transmission costs relative to the Limited framework under Mid-Demand 90% by 2035 assumptions

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.

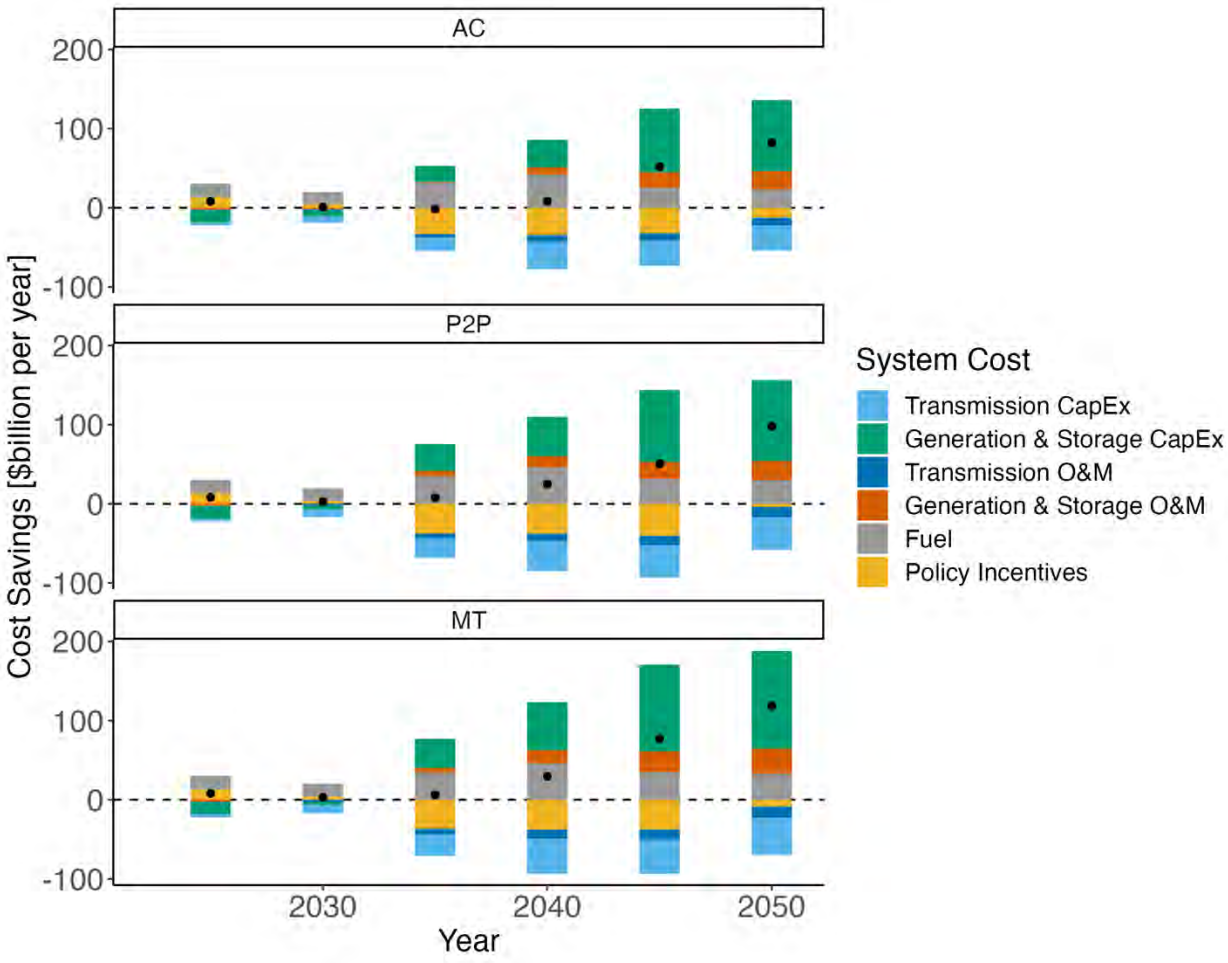


Figure 18. Source of cost savings (real $billion per year) compared to the Limited framework under Mid-Demand 90% by 2035 assumptions

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).

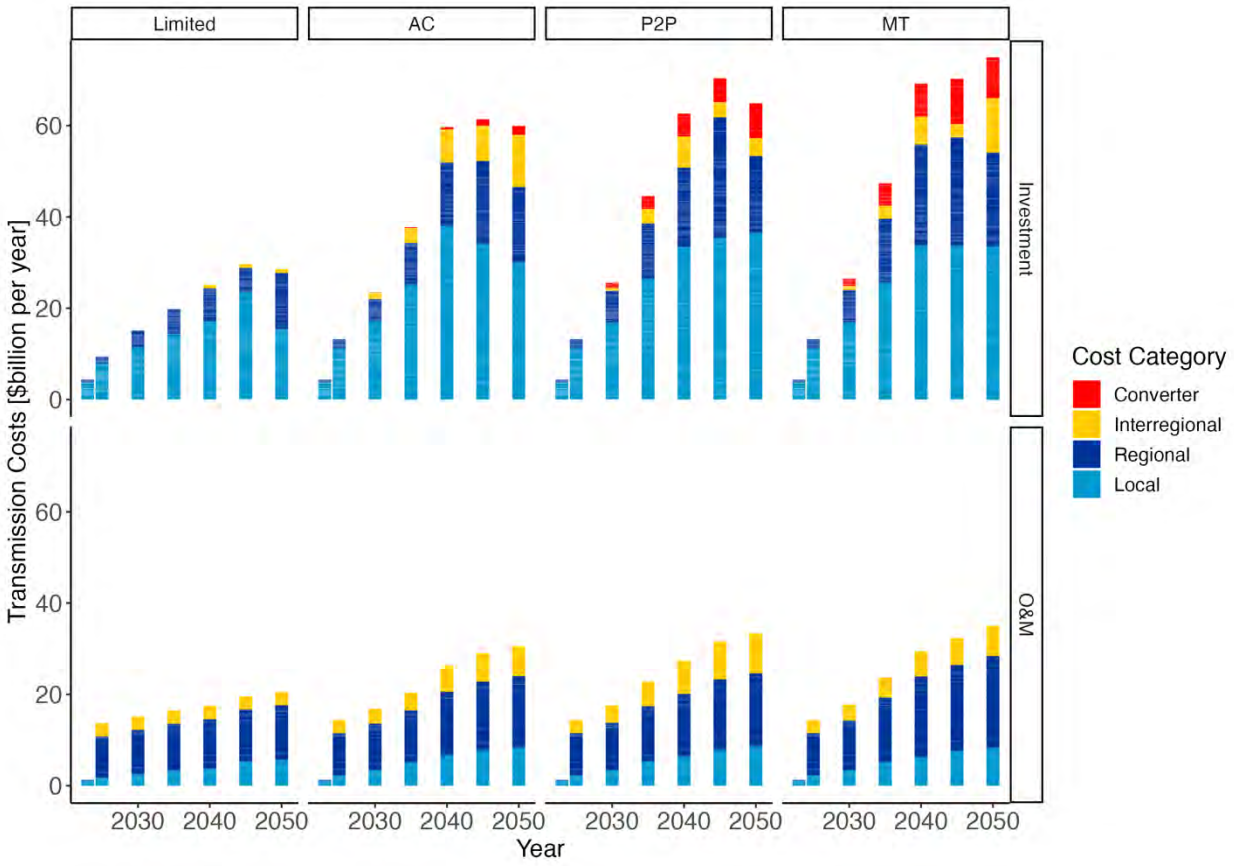


Figure 19. Transmission costs under Mid-Demand 90% by 2035 assumptions

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).

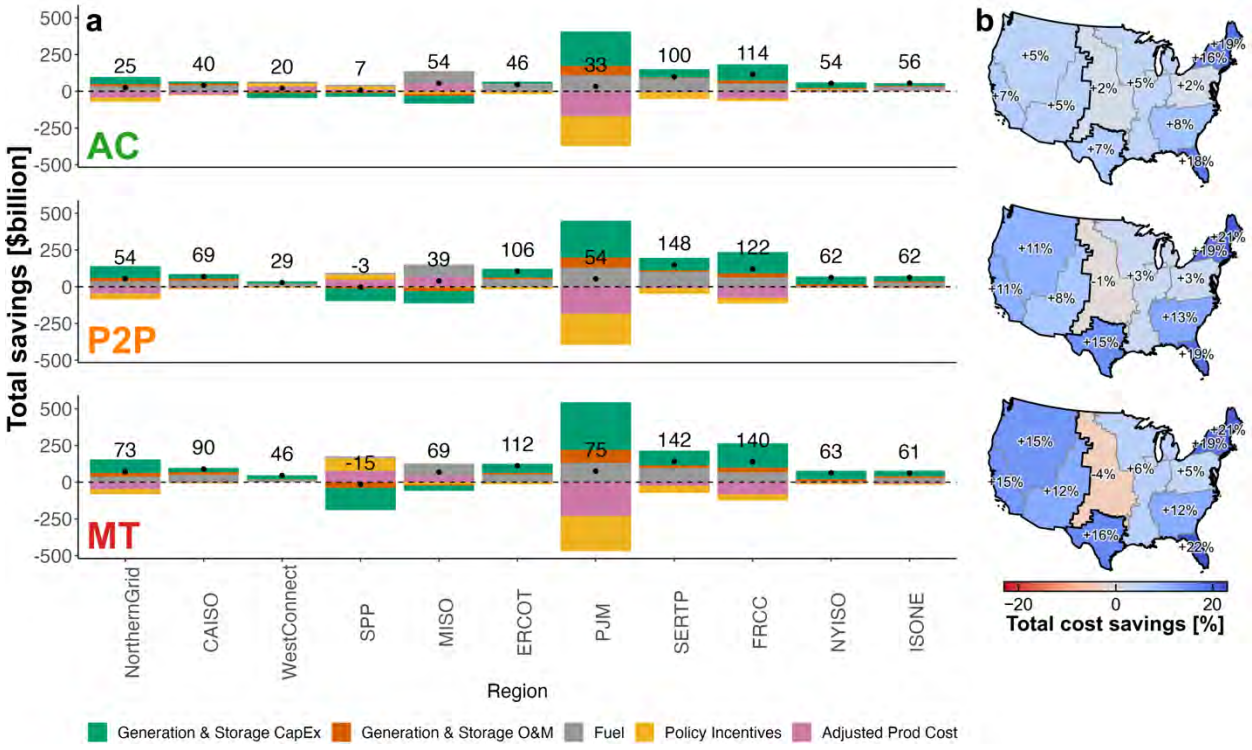


Figure 20. Net present value of system savings by region in absolute $billion (a) and percentage (b) of avoided costs relative to the Limited framework under Mid-Demand 90% by 2035 assumptions

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.

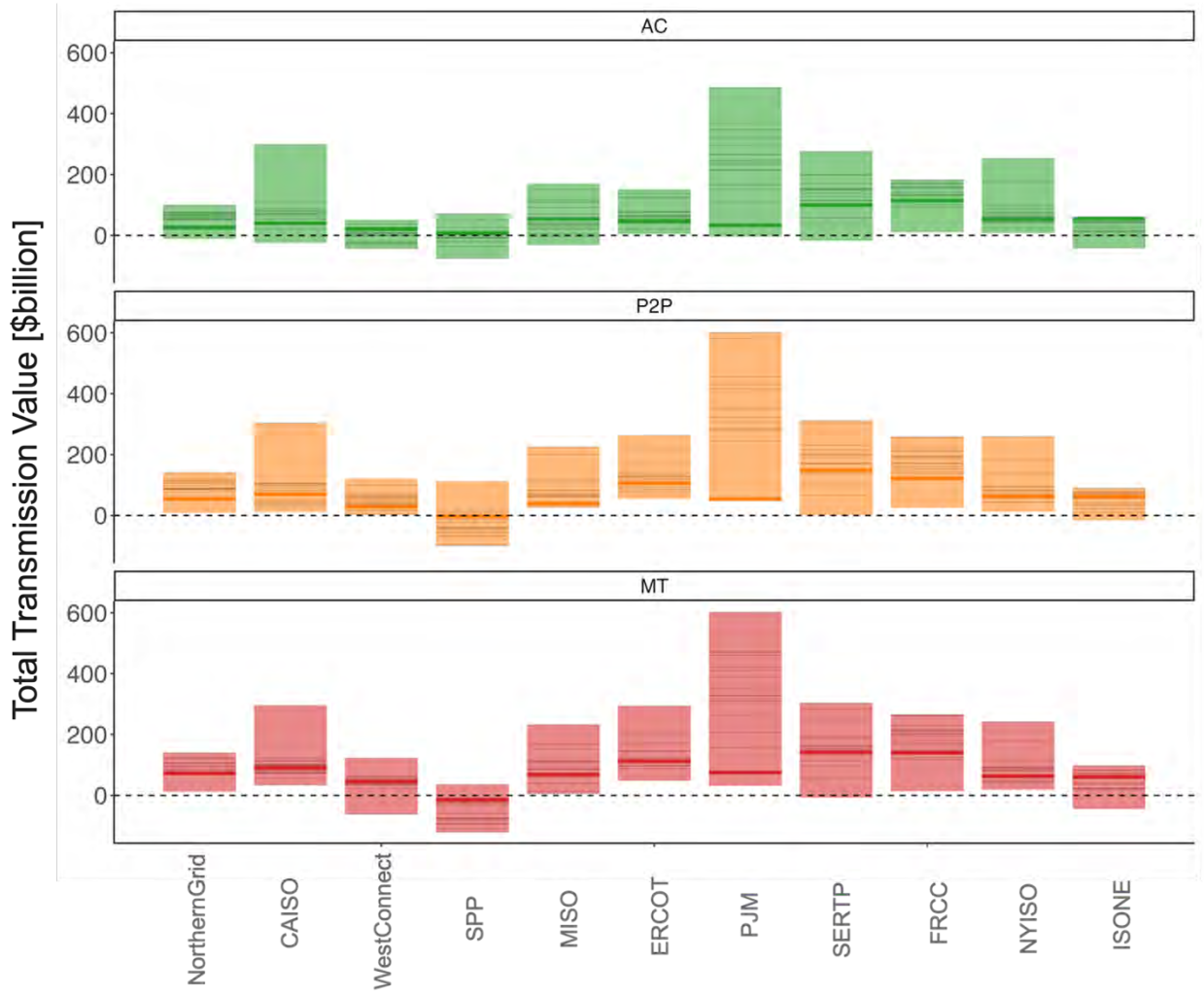


Figure 21. Net present value of total system cost savings to each transmission planning region relative to the Limited framework under Mid-Demand 90% by 2035 assumptions

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).

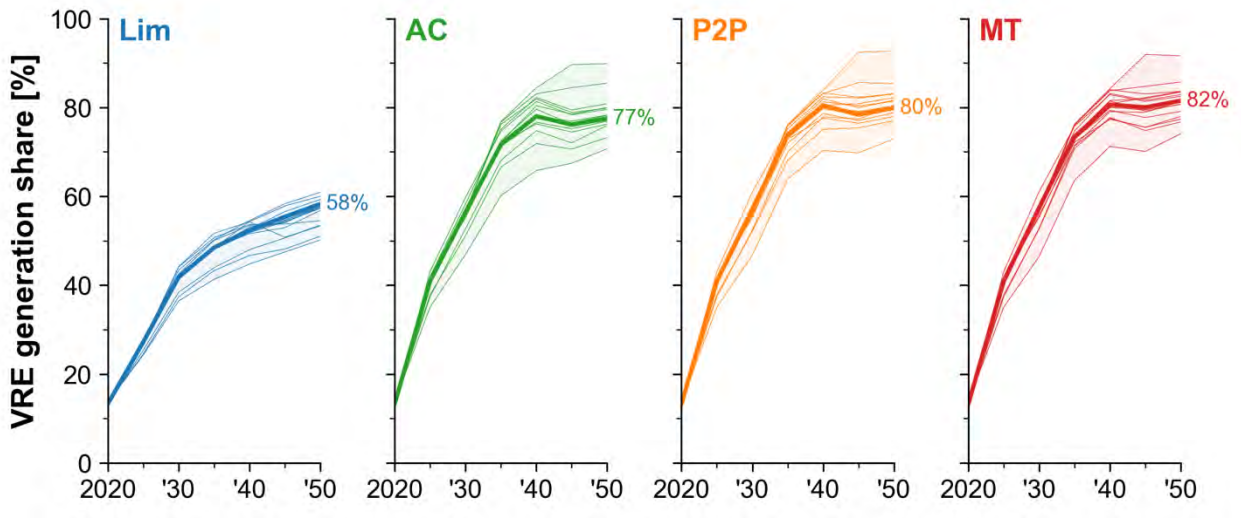


Figure 22. VRE share of total generation for the Mid-Demand 90% by 2035 scenarios for each transmission framework

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.

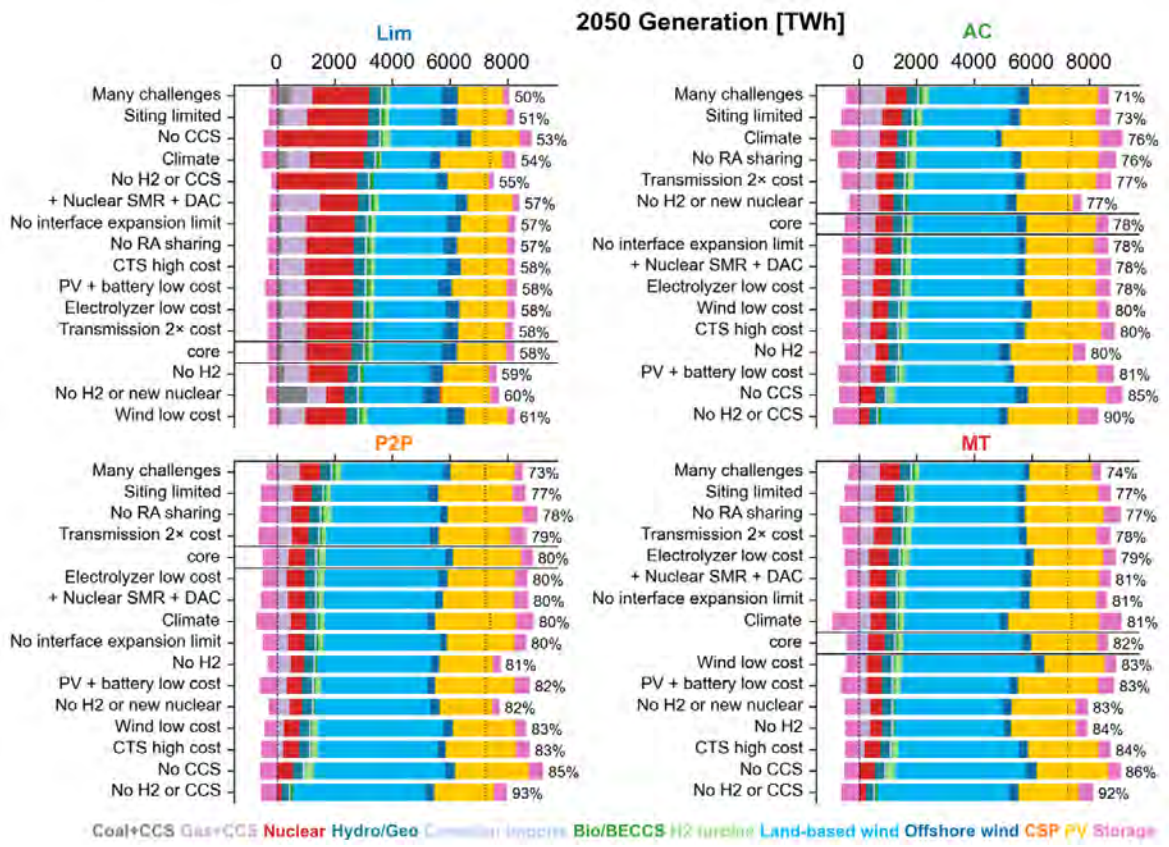


Figure 23. National generation mix in 2050 for the Mid-Demand 90% by 2035 scenarios for each transmission framework and sensitivity case

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.

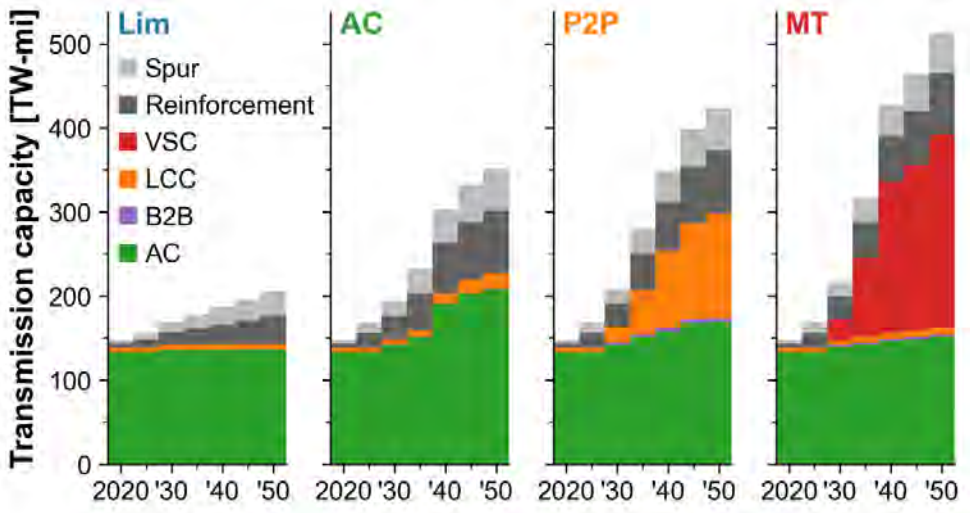


Figure 24. Transmission capacity under Mid-Demand 90% by 2035 assumptions for each transmission framework

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

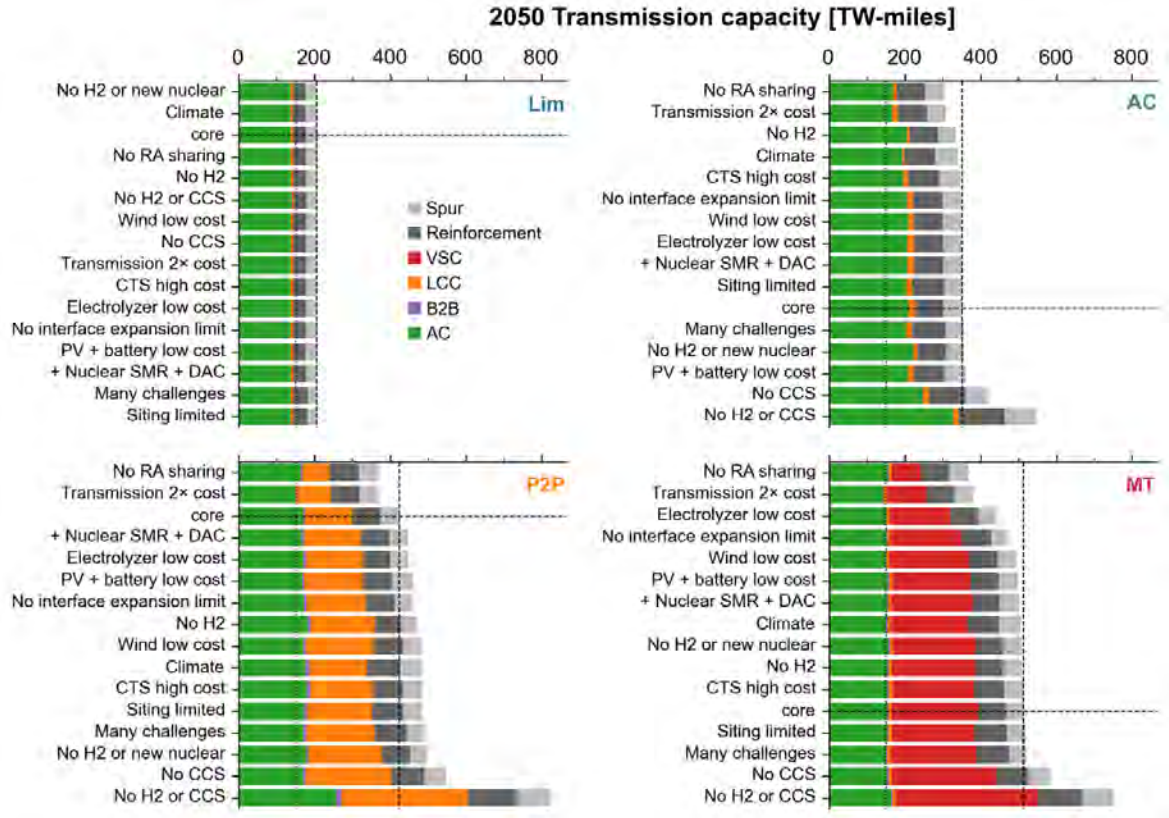


Figure 25. Transmission capacity in 2050 in the Mid-Demand 90% by 2035 scenario for each transmission framework and sensitivity case

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.

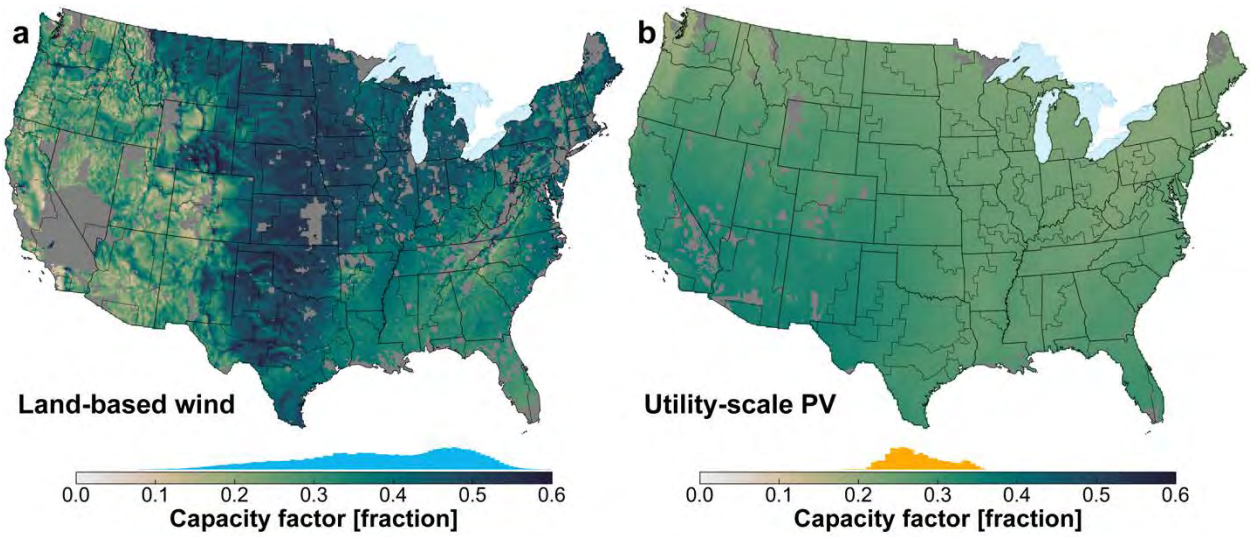


Figure 26. Average capacity factor of land-based wind (a) and utility-scale PV (b) over 2007–2013

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.

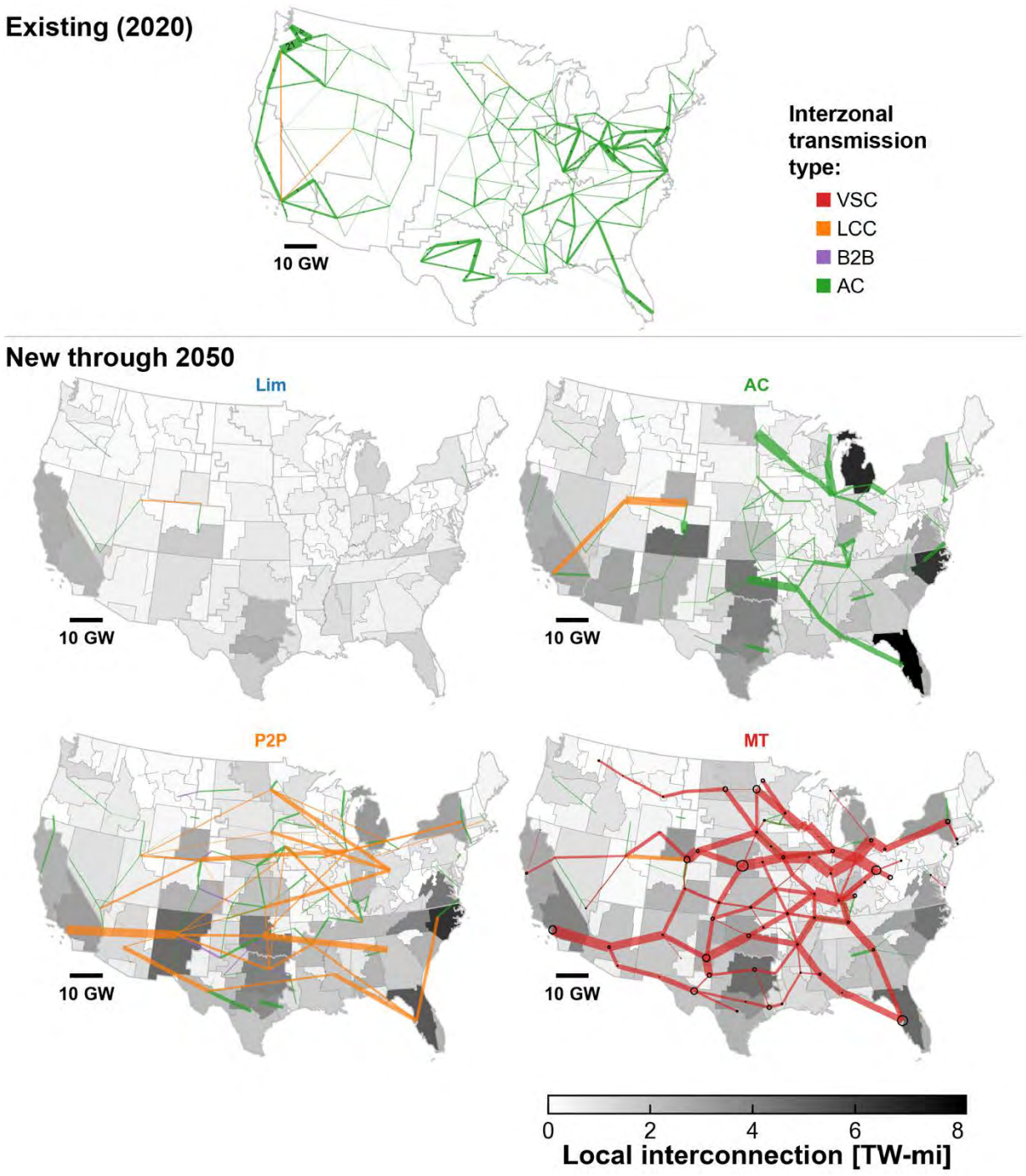


Figure 27. New local and long-distance transmission through 2050 in the Mid-Demand 90% by 2035 scenarios for each transmission framework, with existing 2020 long-distance transmission capacity for context (top)

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.

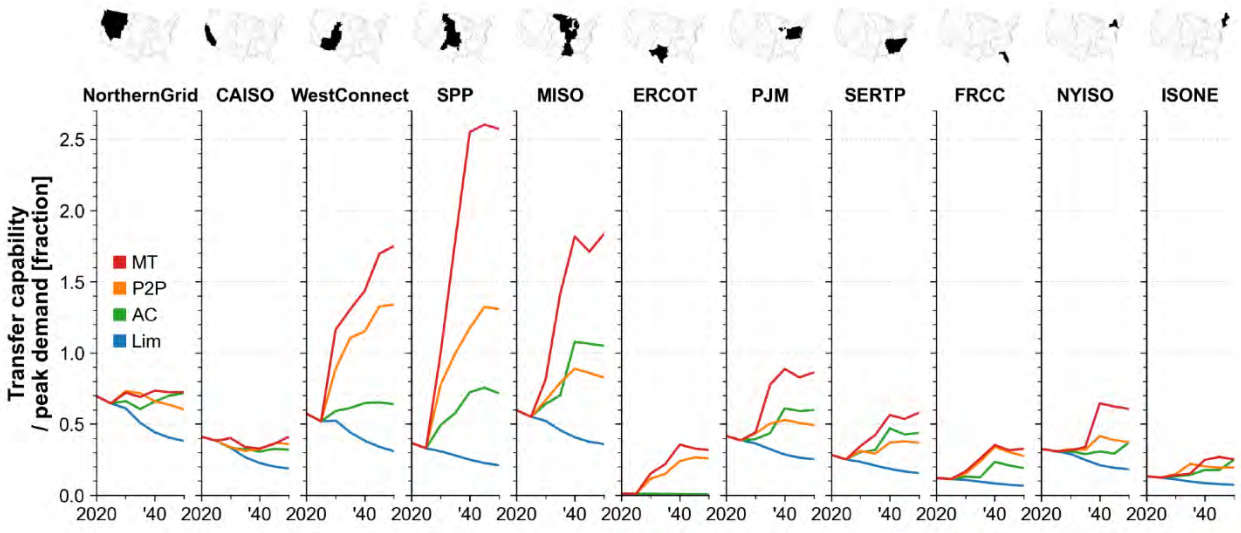


Figure 28. Ratio of interregional transfer capability to peak demand for the 11 planning regions with Mid-Demand 90% by 2035 assumptions across the four transmission frameworks

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.

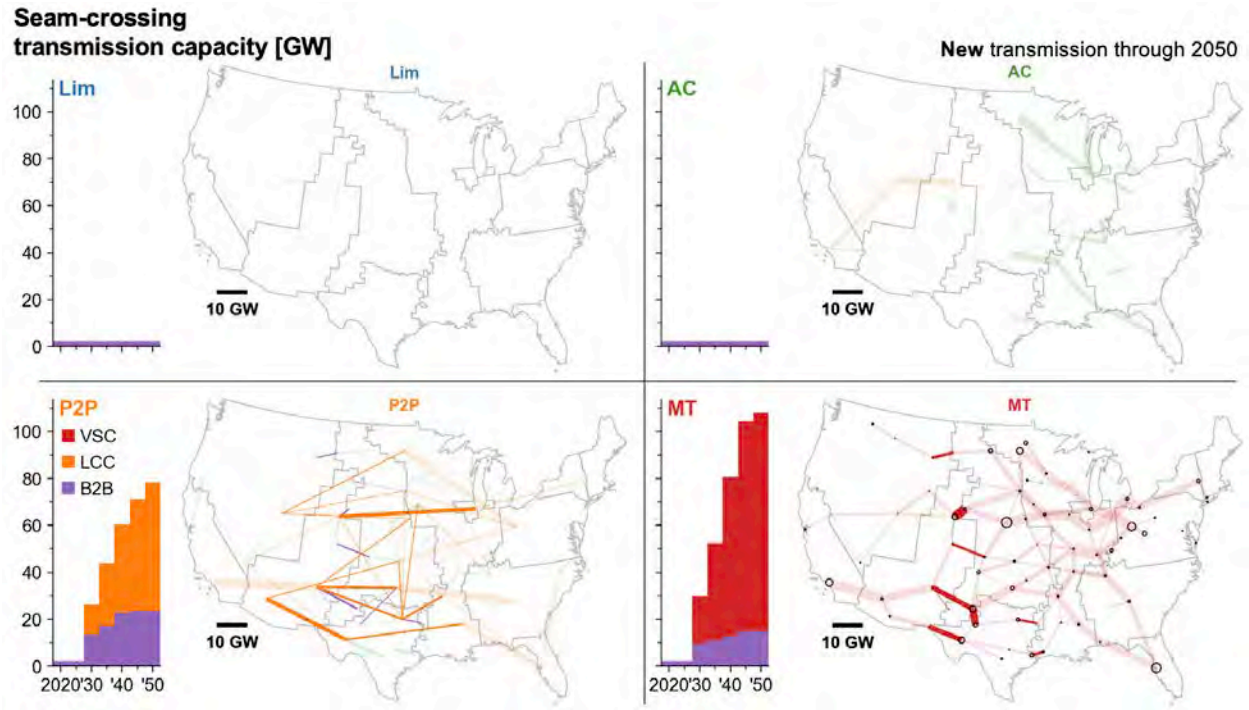


Figure 29. New interconnection-seam-crossing transmission capacity in each of the transmission frameworks with Mid-Demand 90% by 2035 assumptions.

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.

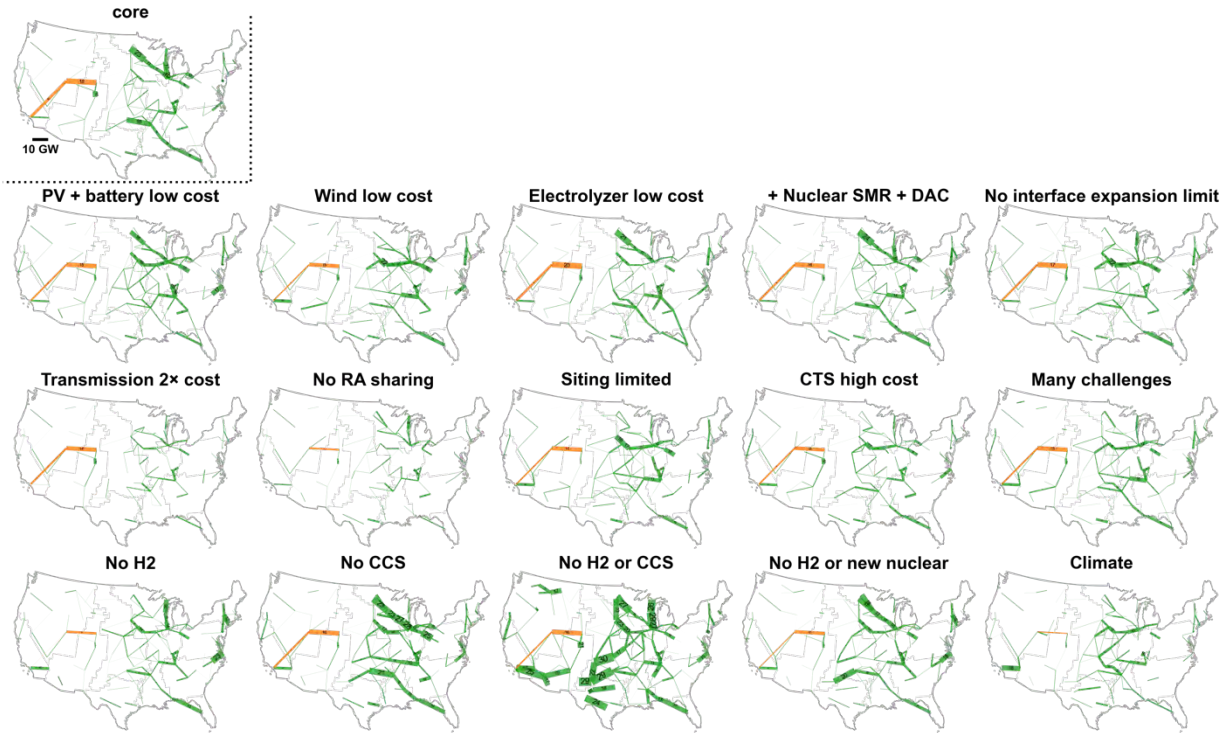


Figure 30. New long-distance transmission additions through 2050 with Mid-Demand 90% by 2035 assumptions for each sensitivity case under the AC transmission framework

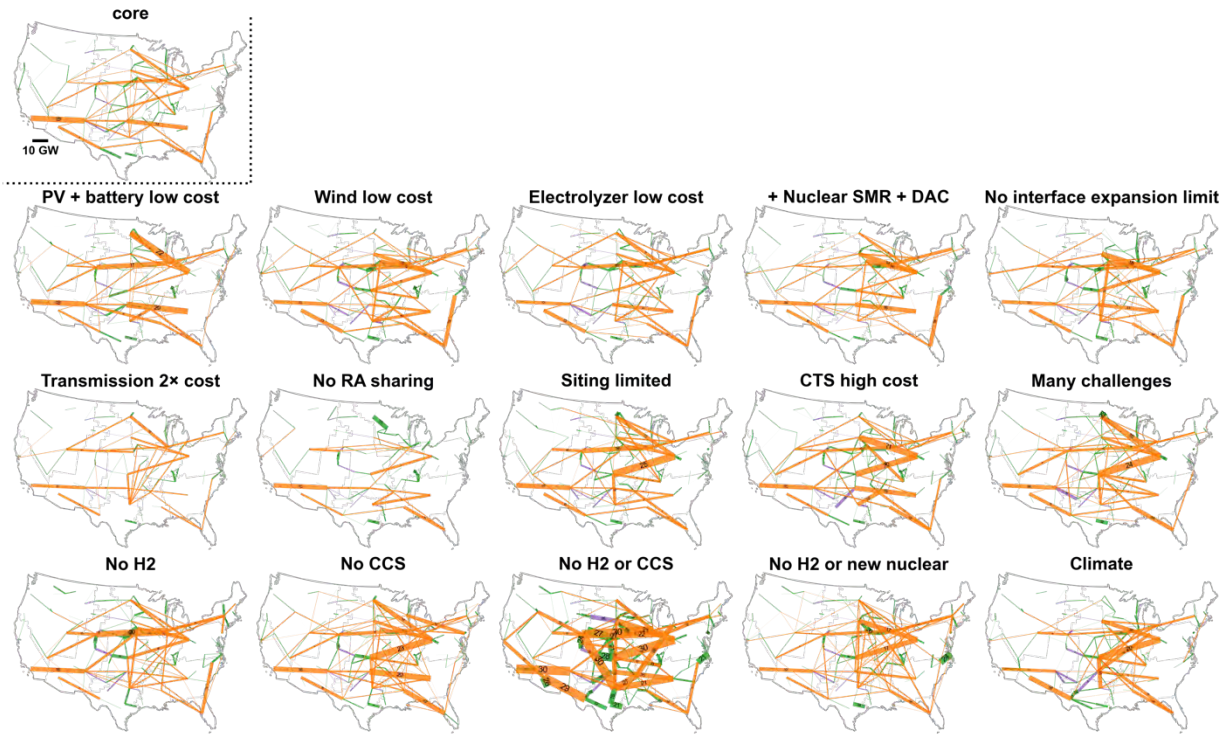


Figure 31. New long-distance transmission additions through 2050 with Mid-Demand 90% by 2035 assumptions for each sensitivity case under the P2P transmission framework

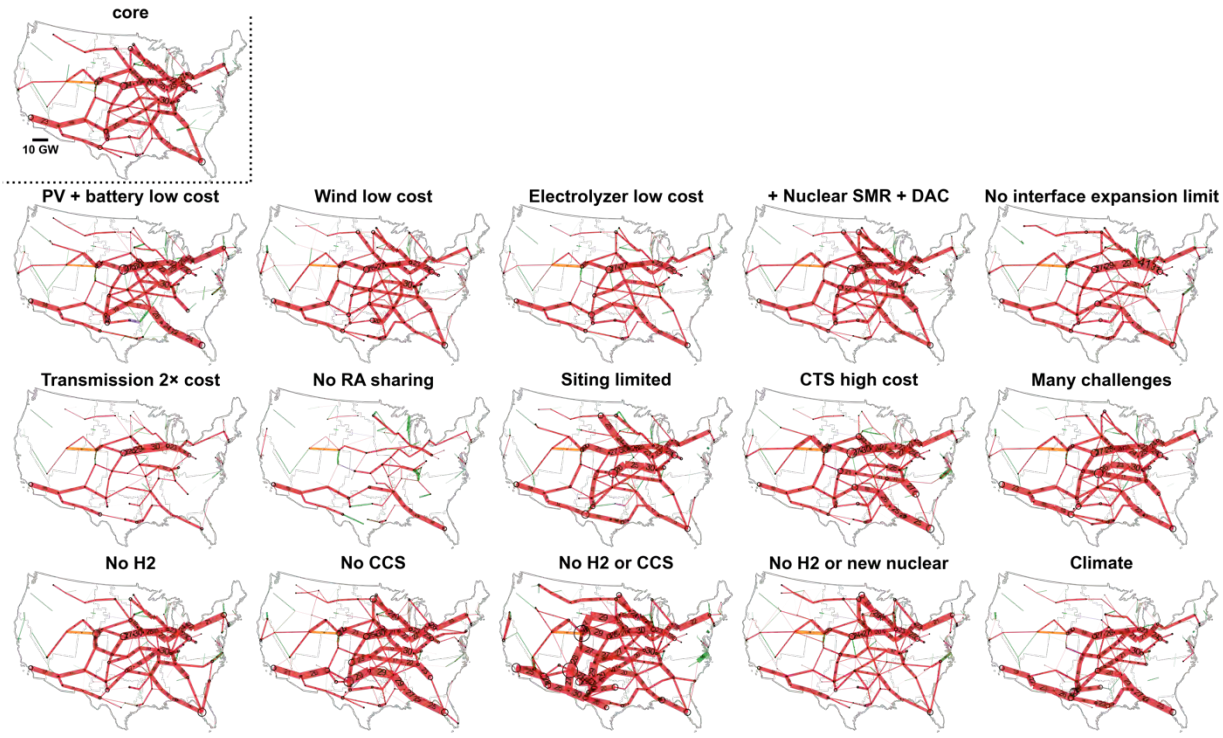


Figure 32. New long-distance transmission additions through 2050 with Mid-Demand 90% by 2035 assumptions for each sensitivity case under the MT transmission framework

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.

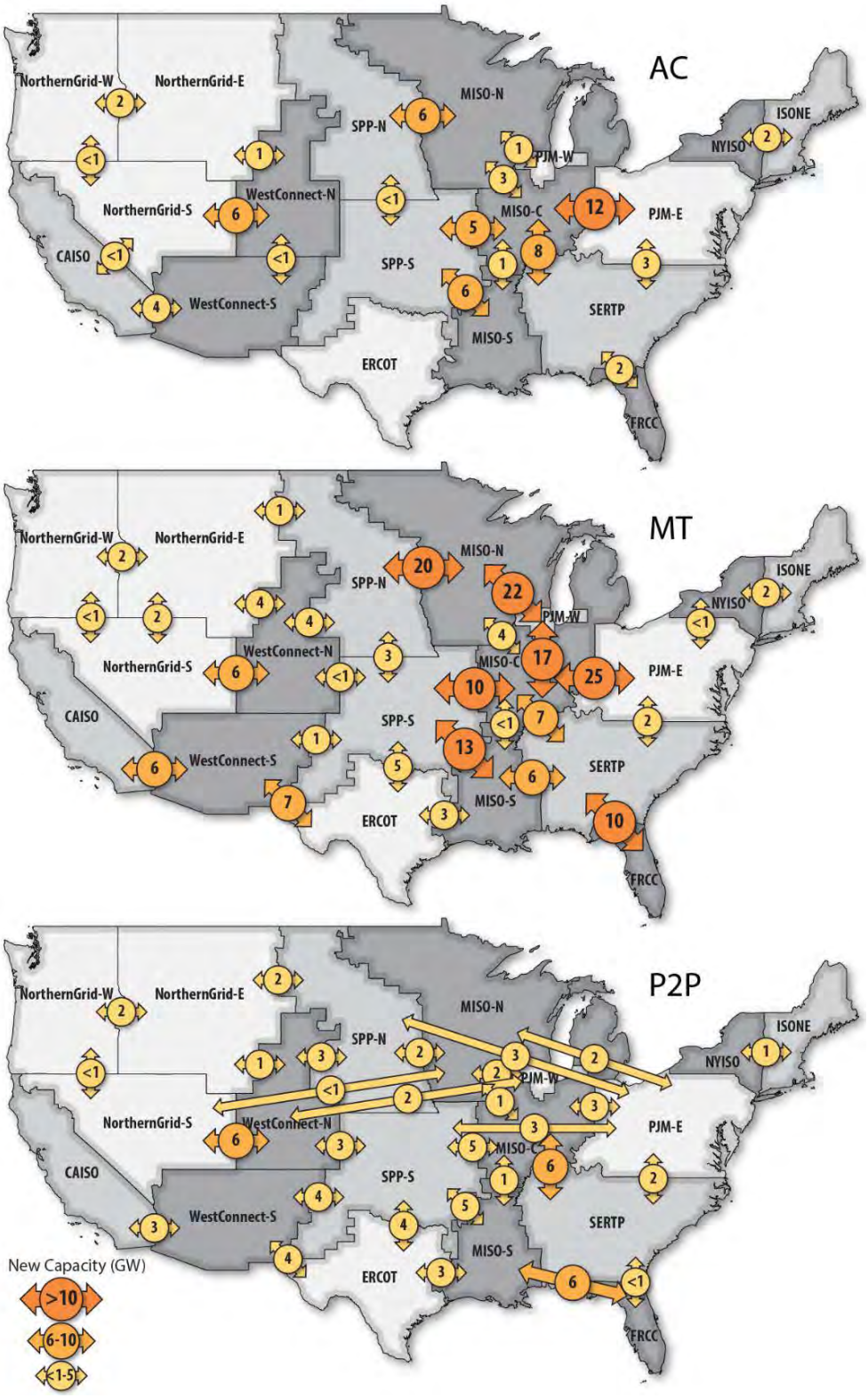
High Opportunity Transmission

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.

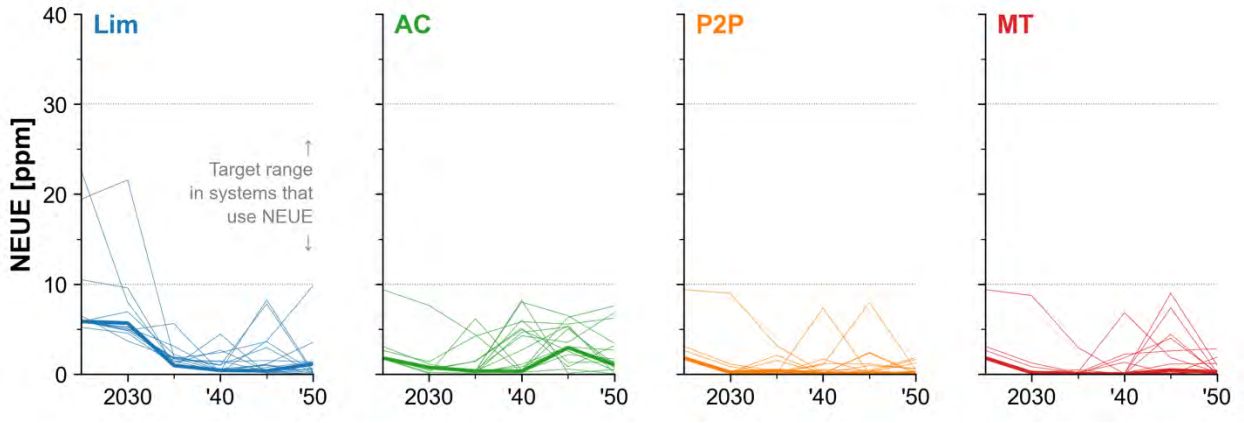


Figure 33. Normalized expected unserved energy (NEUE) in each transmission framework and sensitivity case with Mid-Demand 90% by 2035 assumptions.

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.

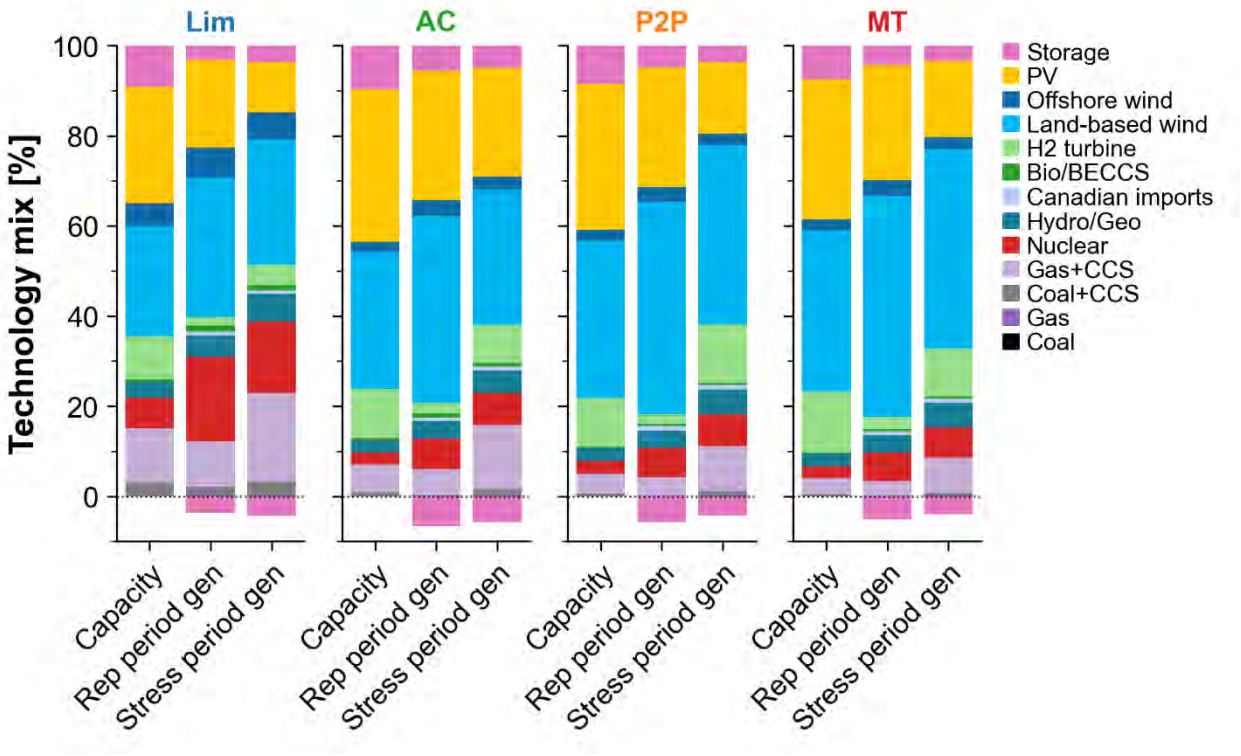


Figure 34. Nameplate capacity mix, representative period generation mix, and stress period generation mix for the core transmission frameworks in 2050 under Mid-Demand 90% by 2035 assumptions.

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).

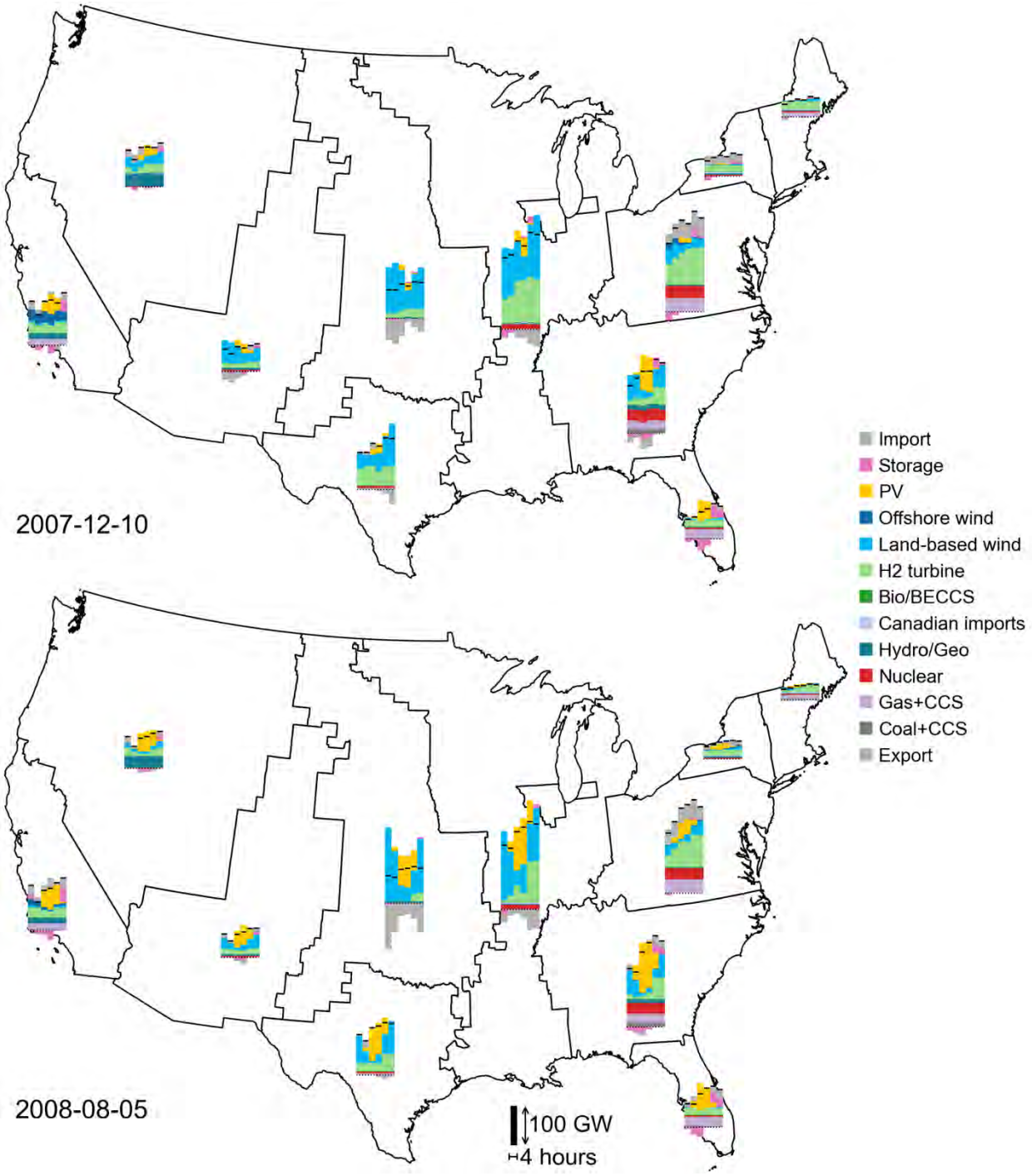


Figure 35. Regional dispatch in the MT framework under Mid-Demand 90% by 2035 assumptions in 2050 modeled in ReEDS during two example stress periods

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]

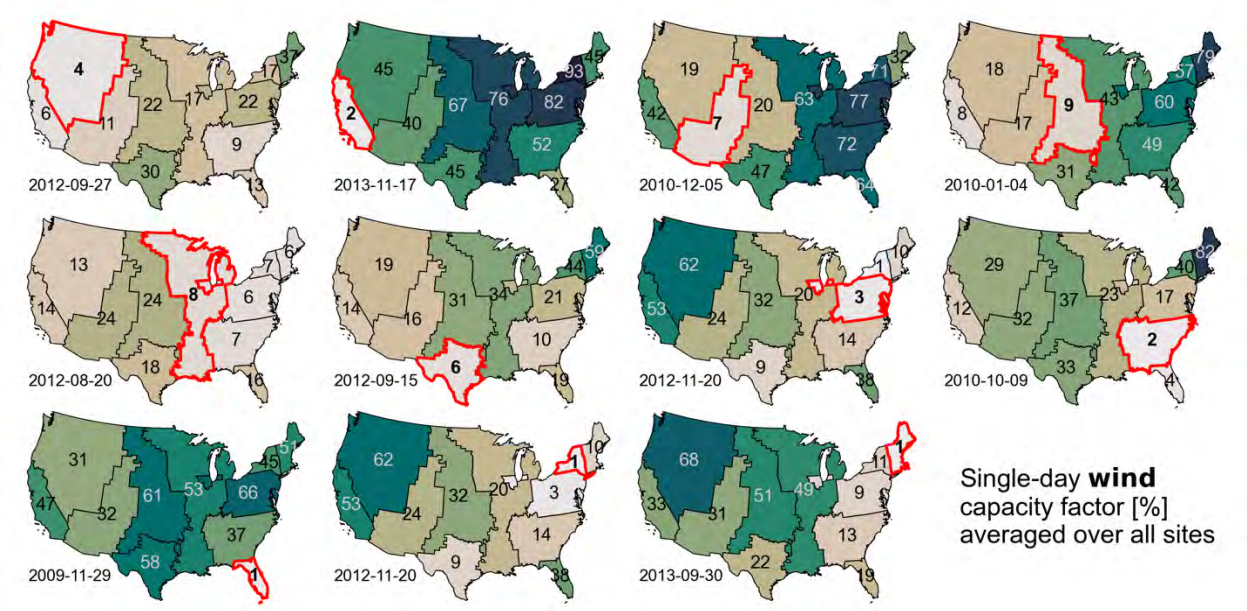


Figure 36. Single-day wind capacity factor on the least-windy day from 2007 to 2013 weather years in each planning region

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.

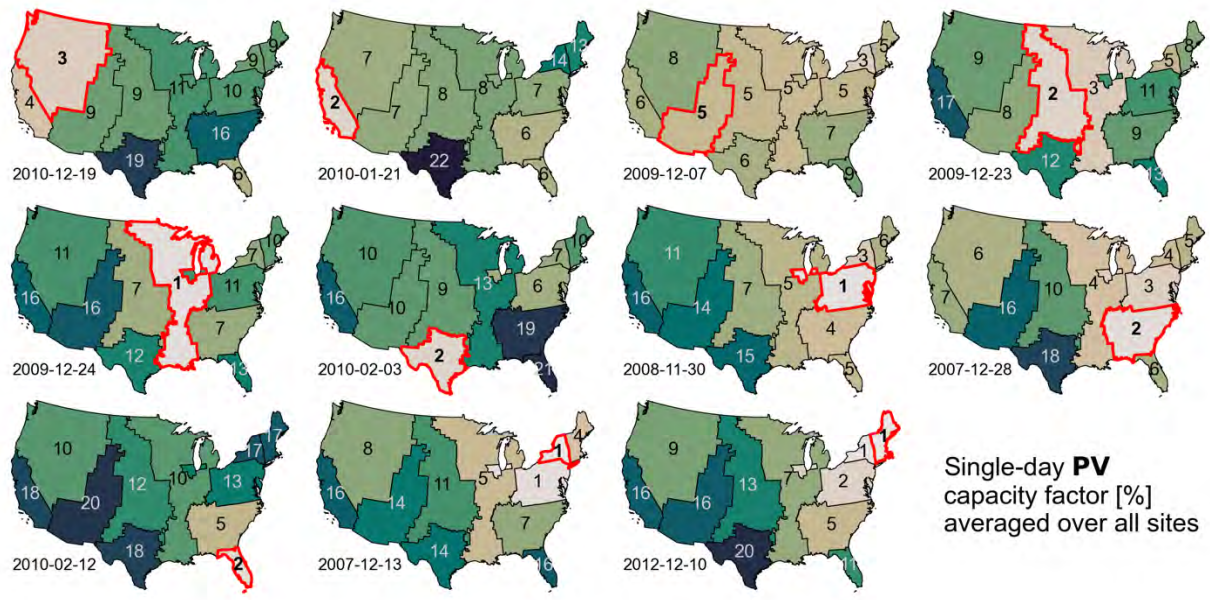


Figure 37. Single-day PV capacity factor on the least-sunny day from 2007 to 2013 weather years in each planning region

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.

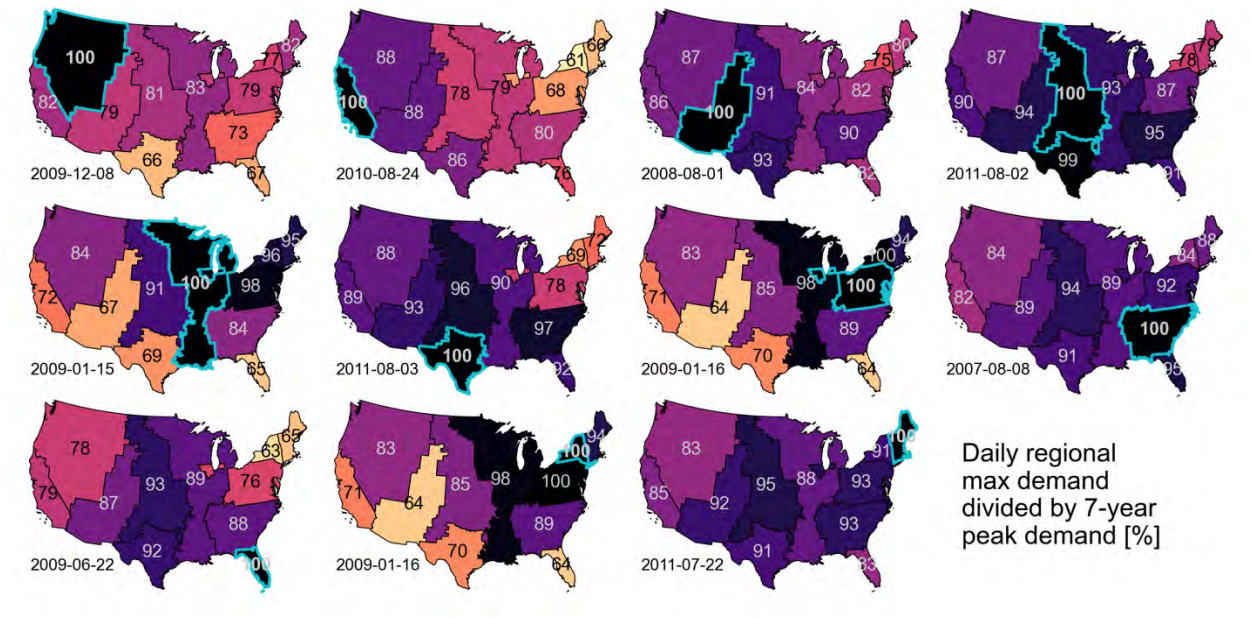


Figure 38. Daily regional maximum demand divided by 7-year peak demand for that region, shown for the regional peak demand day from 2007 to 2013 weather years for each planning region

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.

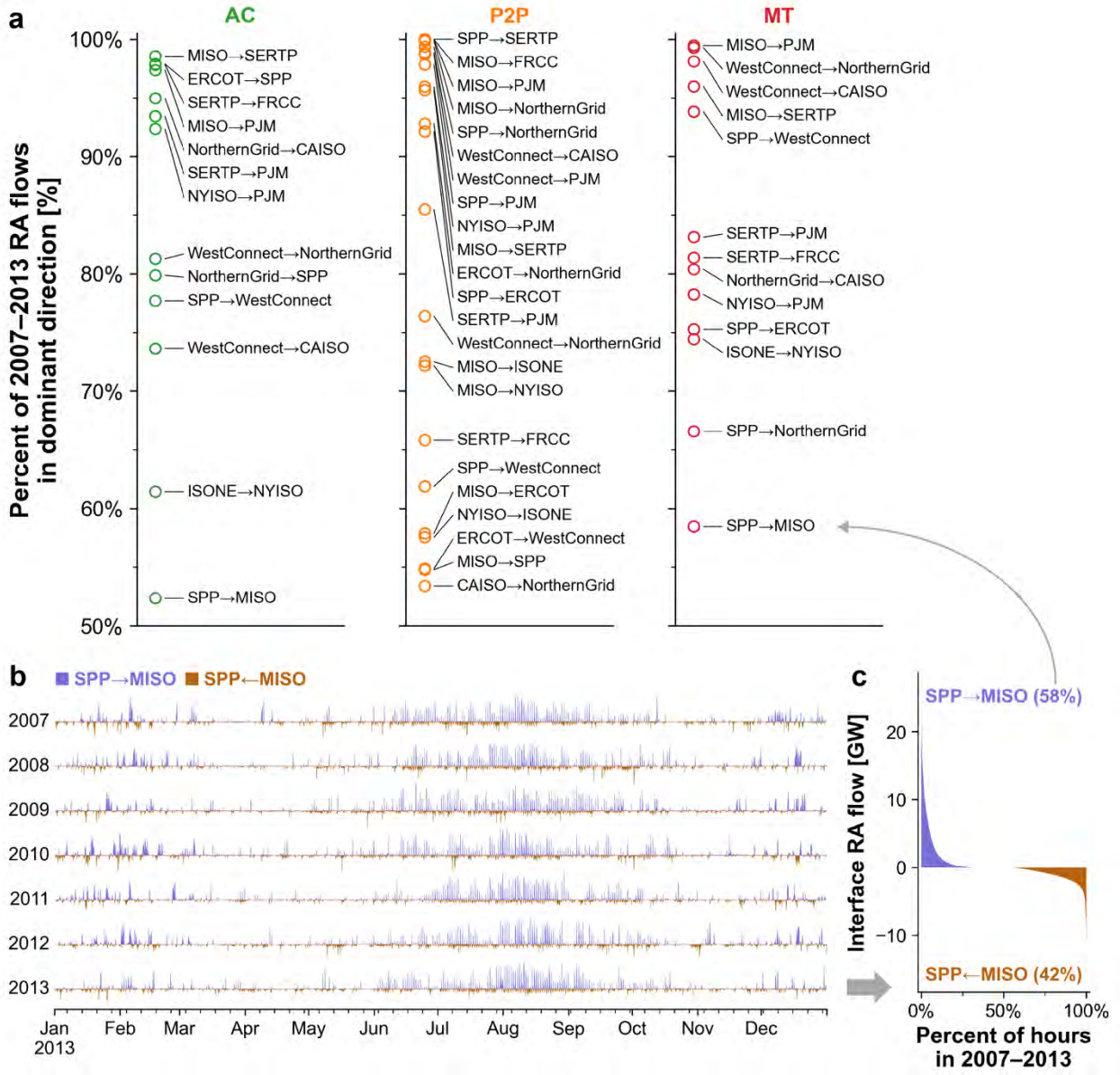


Figure 39. Bidirectional transmission flows between regions for resource adequacy in 2050 under Mid-Demand 90% by 2035 conditions as modeled by PRAS

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.

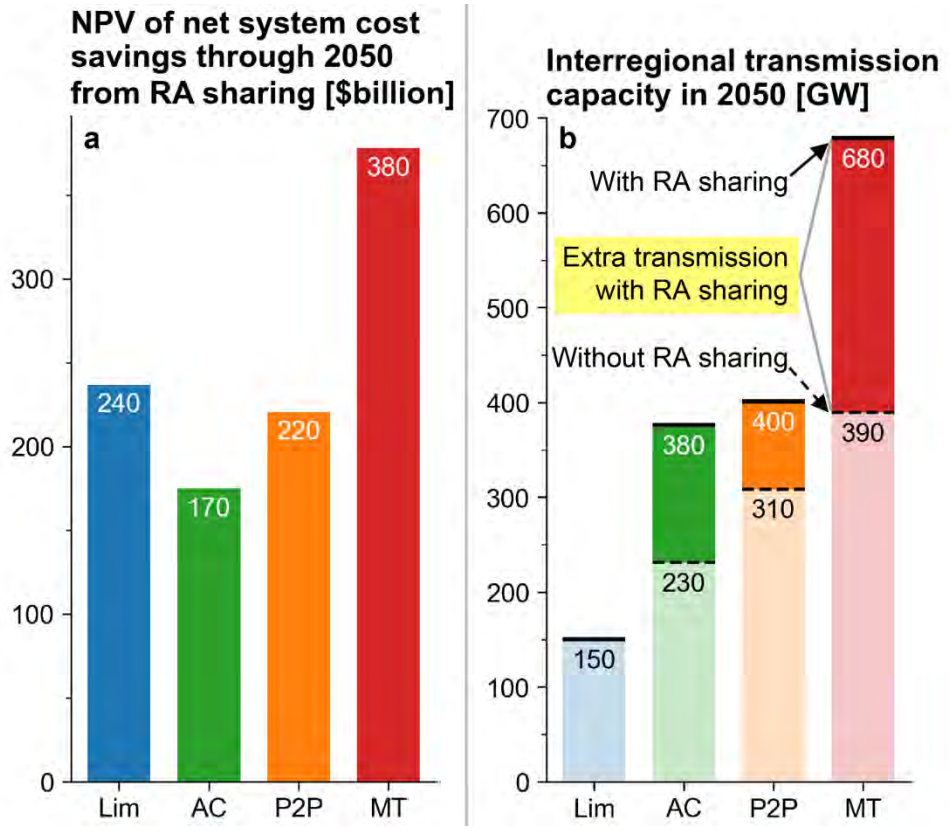


Figure 40. Impact of the allowance of interregional RA sharing on system cost (a) and optimized interregional transmission capacity (b)

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).

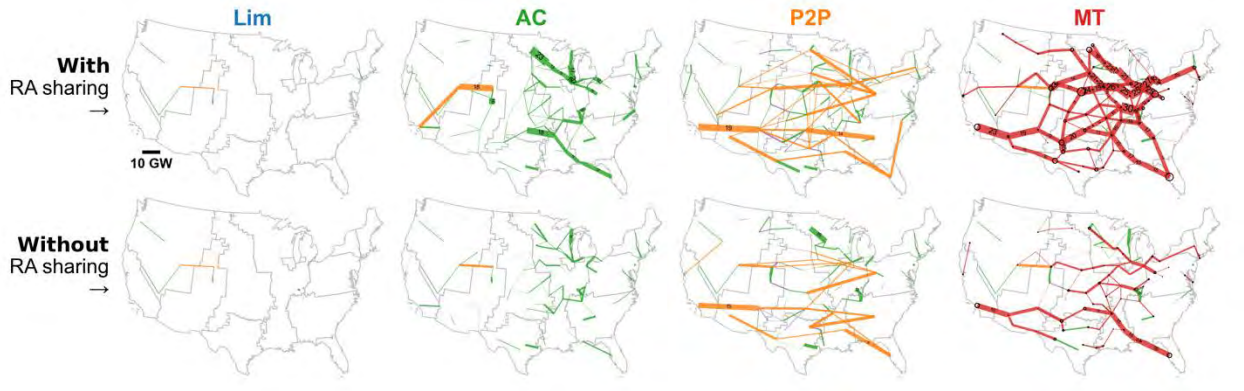


Figure 41. New transmission through 2050 with Mid-Demand 90% by 2035 assumptions for the four transmission frameworks with (top) and without (bottom) RA sharing between planning subregions.

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.

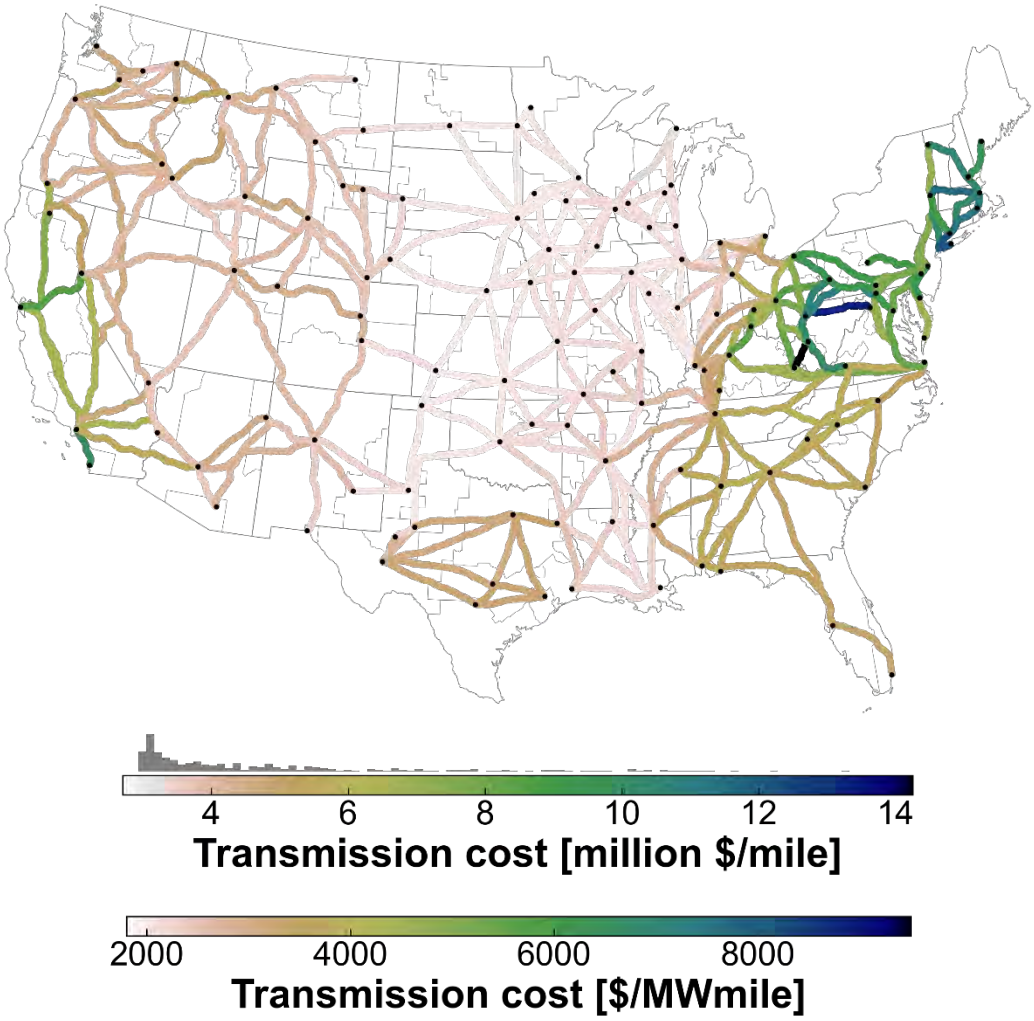


Figure A-1. Interzonal AC transmission cost assumptions

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.

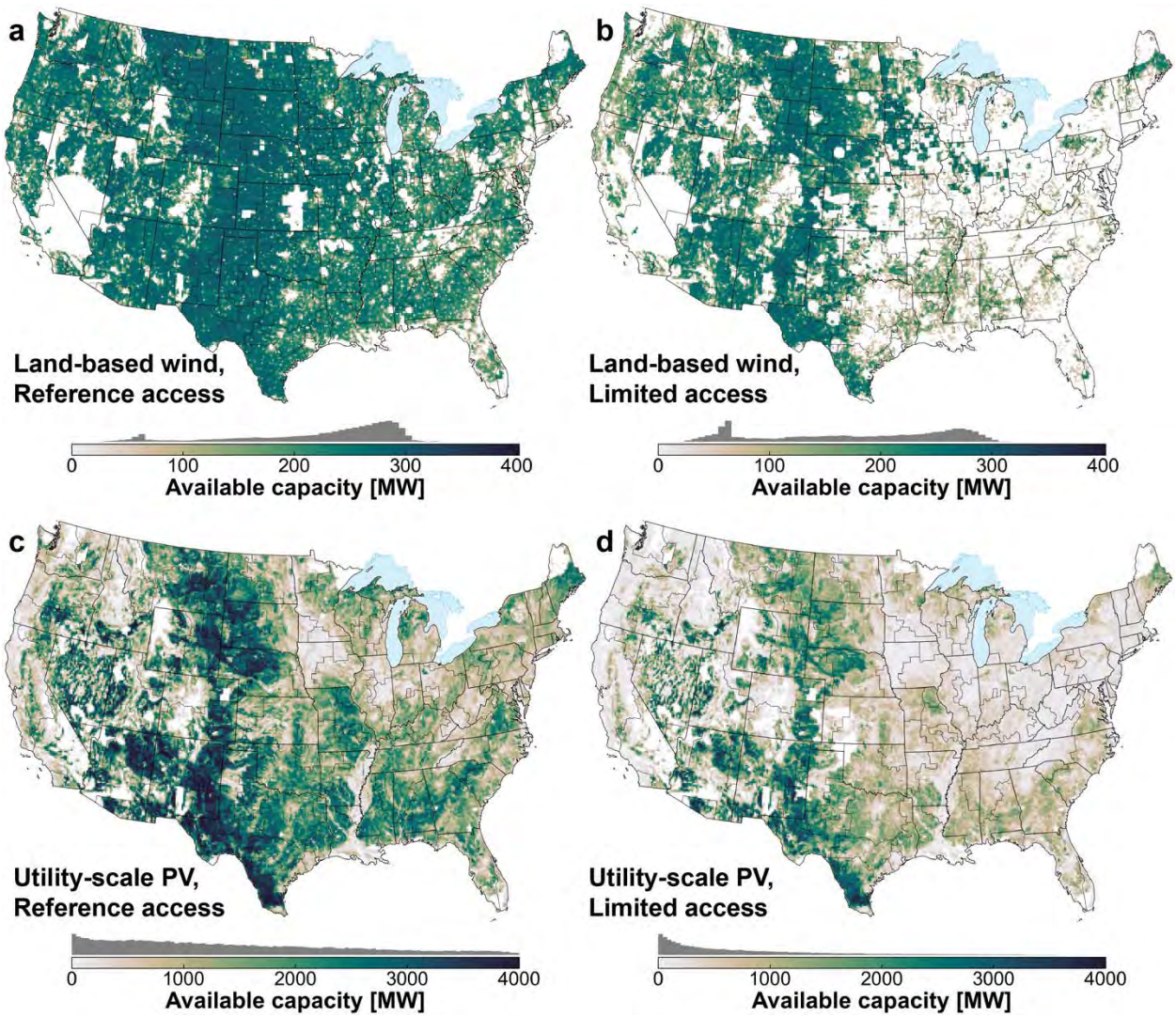


Figure A-2. Available land-based wind (a, b) and utility-scale PV (c, d) capacity under Reference Access (a, c) and Limited Access (b, d) assumptions

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.

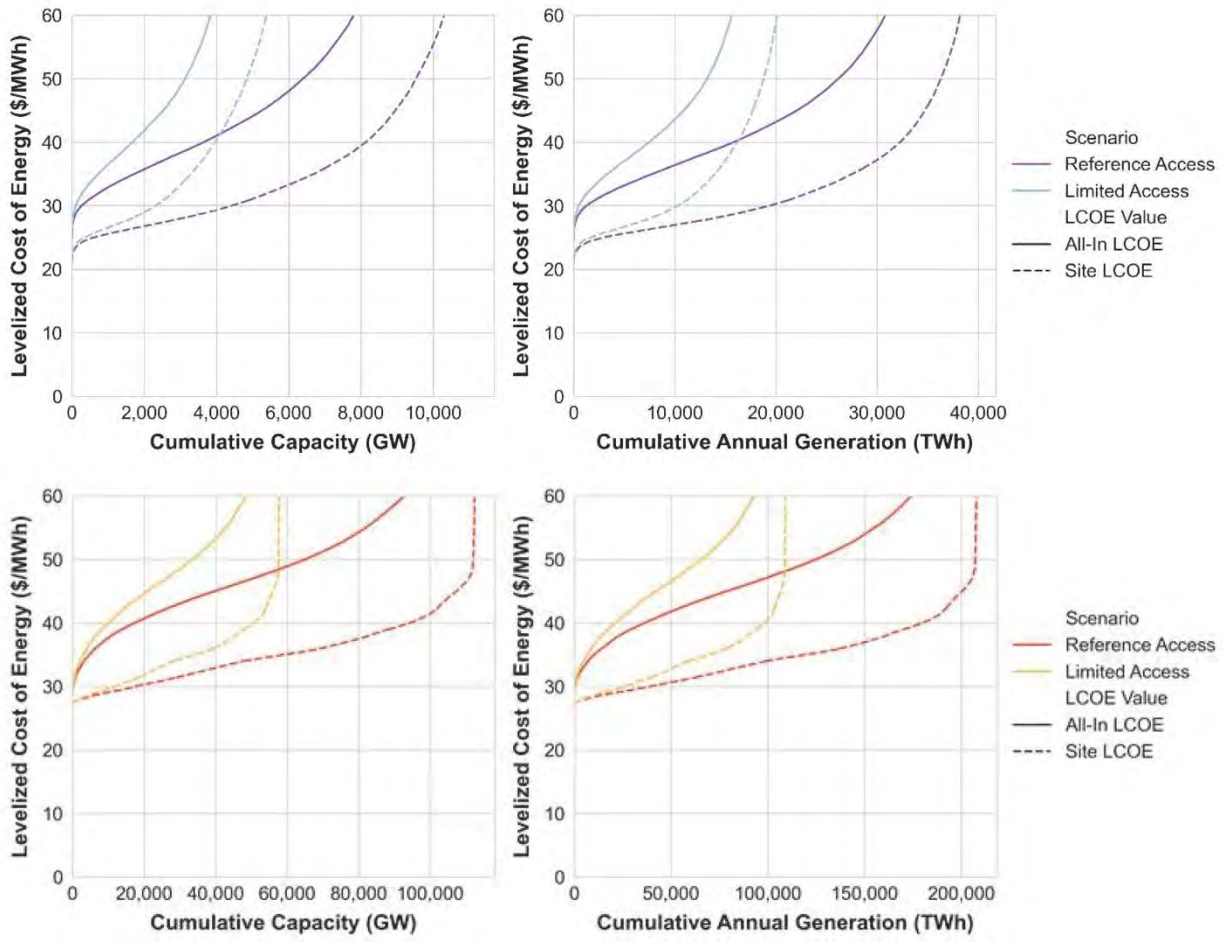


Figure A-3. LCOE supply curves for land-based wind (top) and solar PV (bottom)

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.

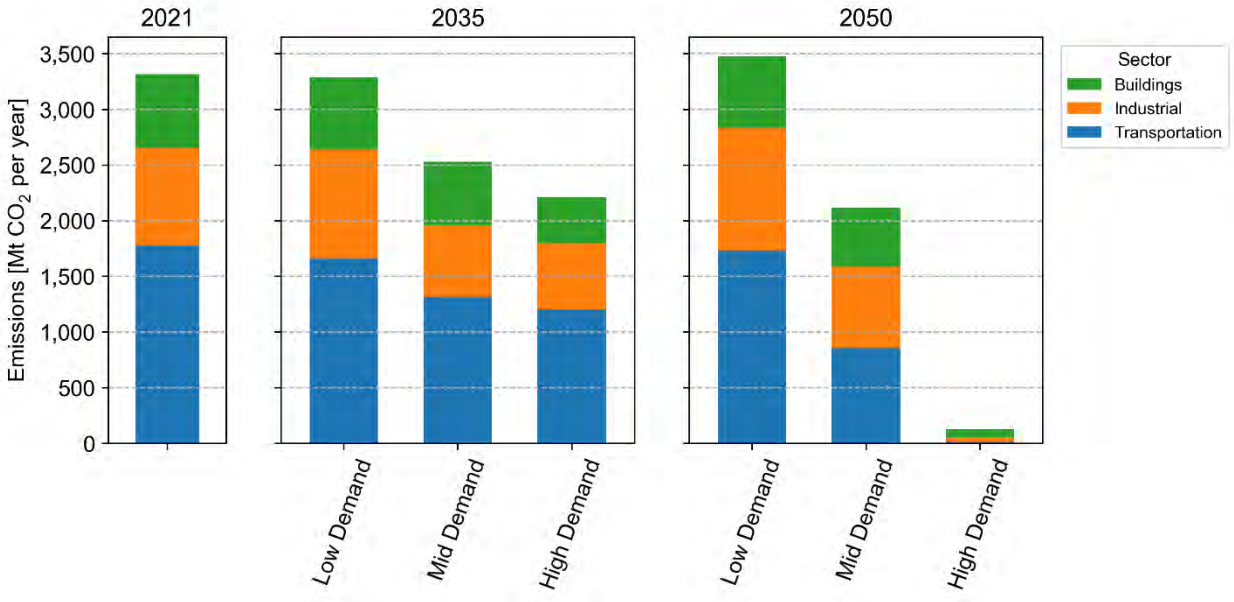


Figure A-4. End-use emissions for the three electricity demand cases

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.

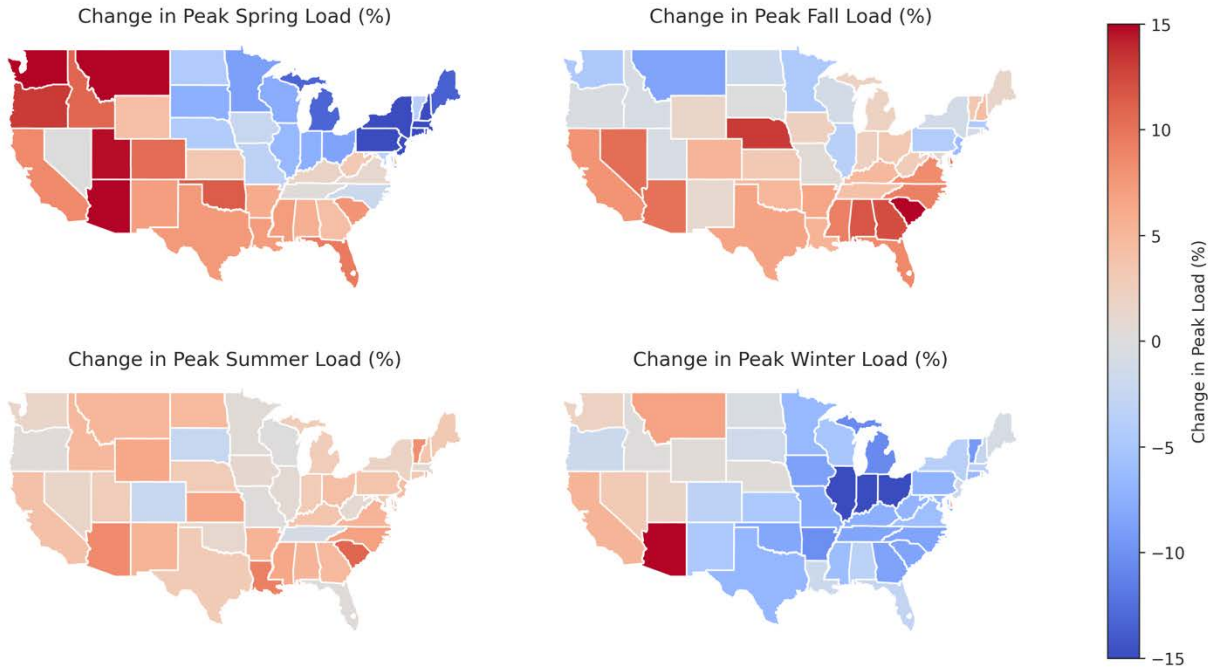


Figure A-5. Changes in seasonal all-sector peak load from historical weather (2007–2013) to future weather impacted by climate change (2050–2056)

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.

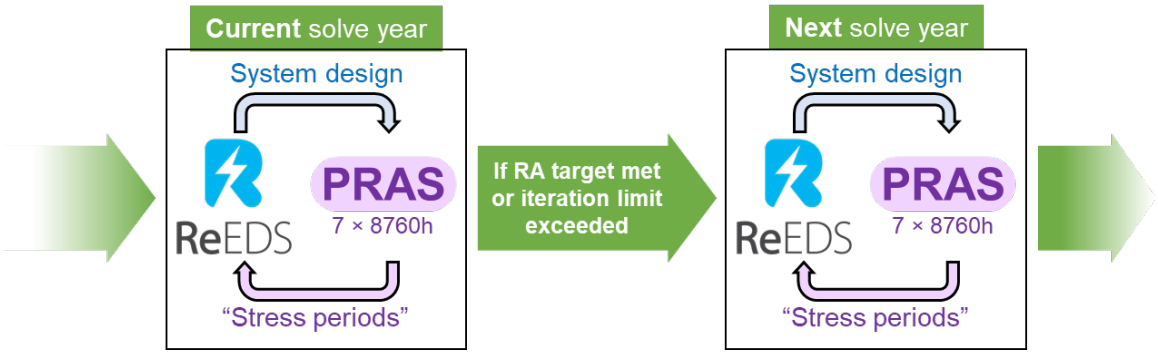


Figure B-1. Integrated capacity expansion and resource adequacy modeling

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

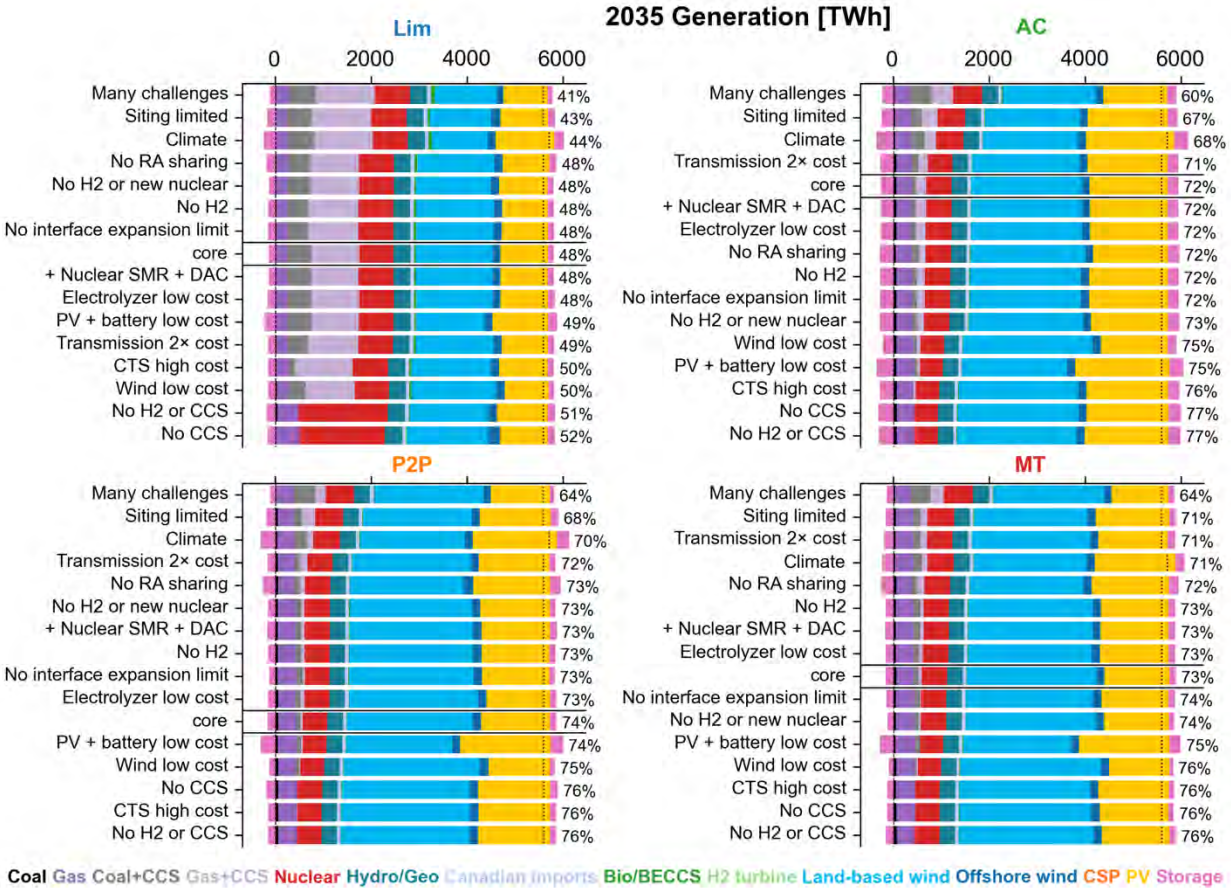


Figure D-1. National generation mix in 2035 with Mid-Demand 90% by 2035 assumptions for each transmission framework and sensitivity case

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.

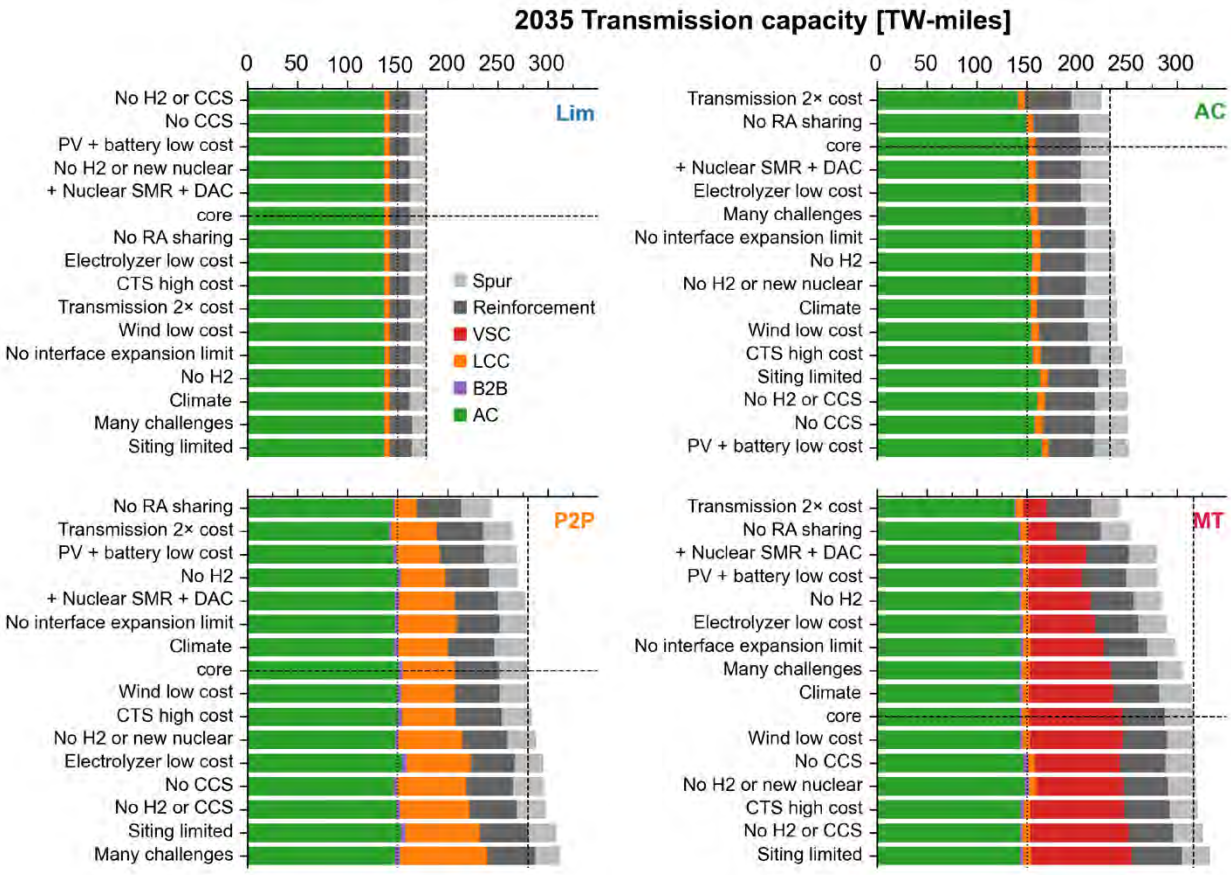


Figure D-2. Transmission capacity in 2035 with Mid-Demand 90% by 2035 assumptions for each transmission framework and sensitivity case

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.

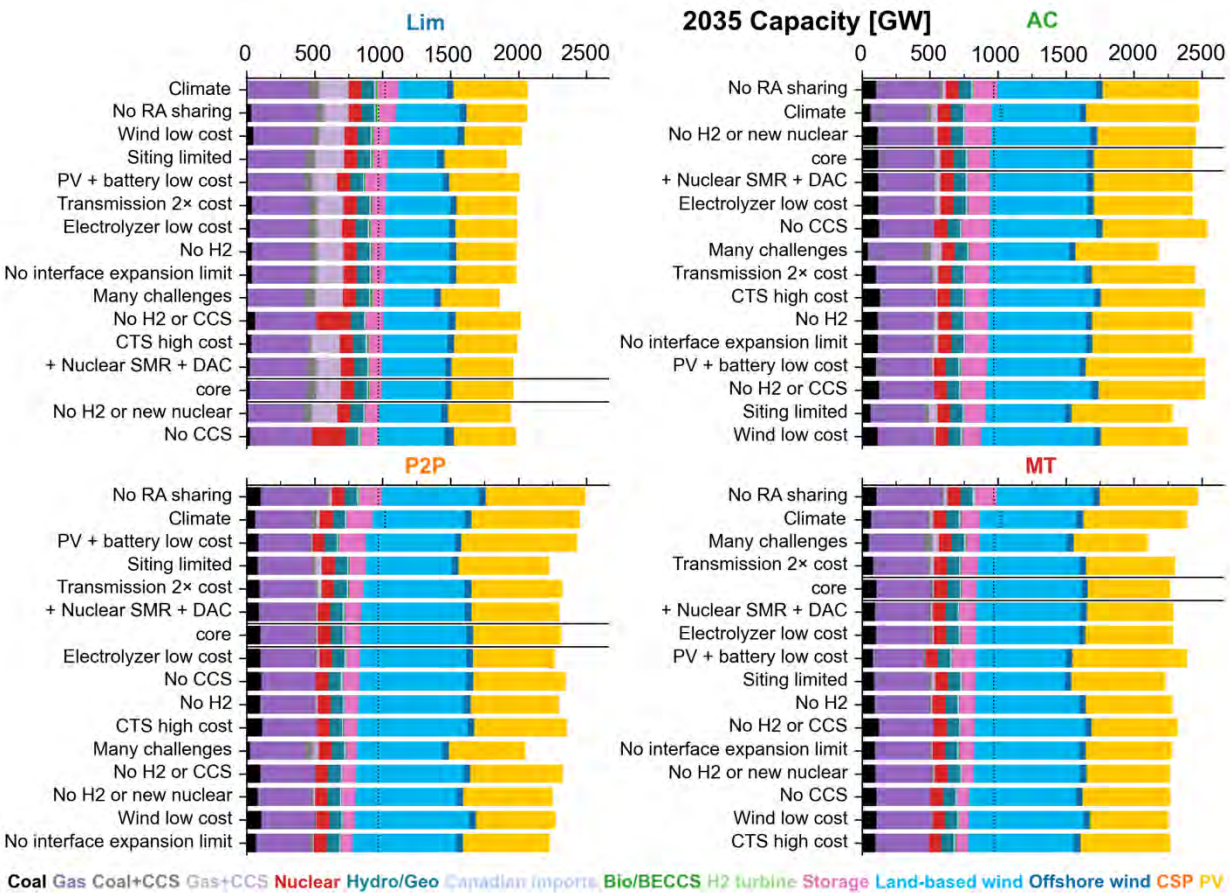


Figure D-3. National capacity mix in 2035 with Mid-Demand 90% by 2035 assumptions for each transmission framework and sensitivity case

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.

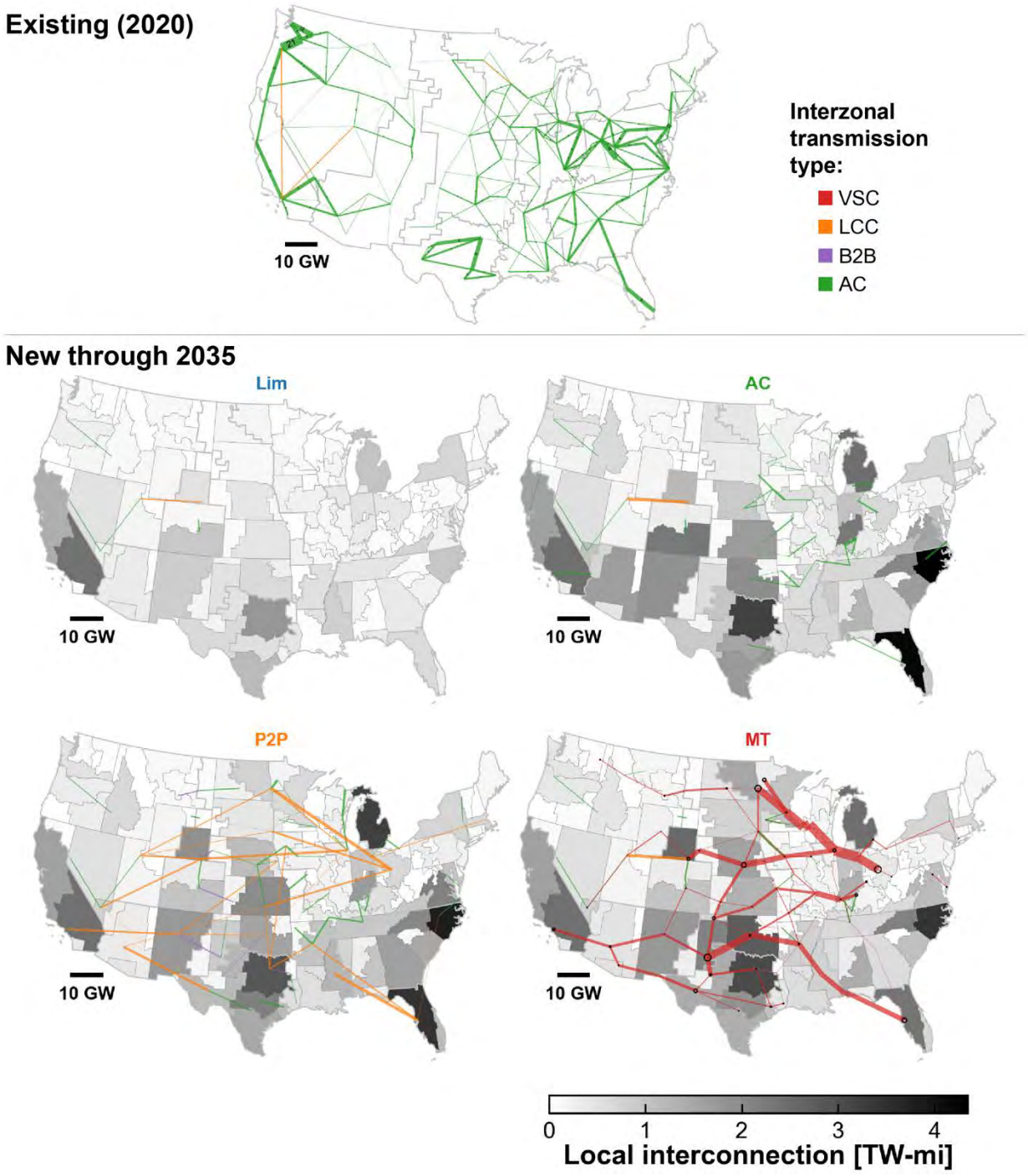


Figure D-4. New local and long-distance transmission through 2035 under Mid-Demand 90% by 2035 assumptions for each of the four transmission frameworks, with existing 2020 long-distance transmission capacity for context (top)

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.

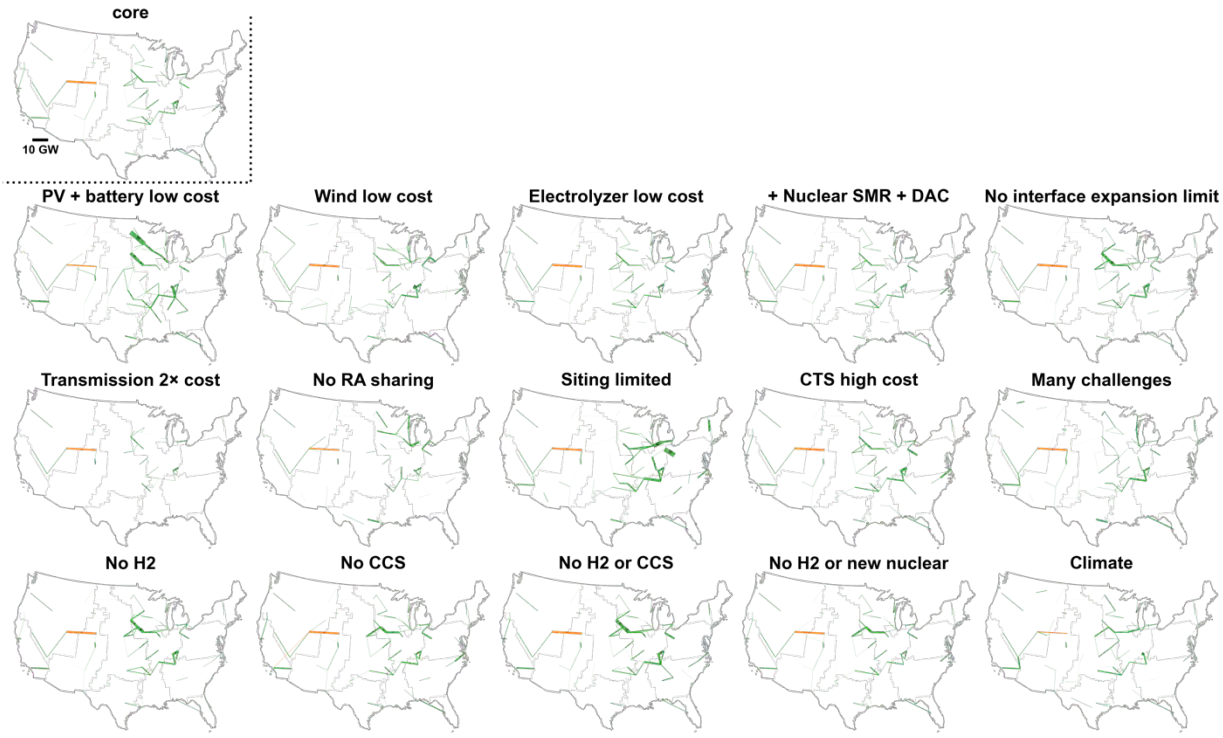


Figure D-5. New long-distance transmission additions through 2050 with Mid-Demand 90% by 2035 assumptions for each sensitivity case under the AC transmission framework

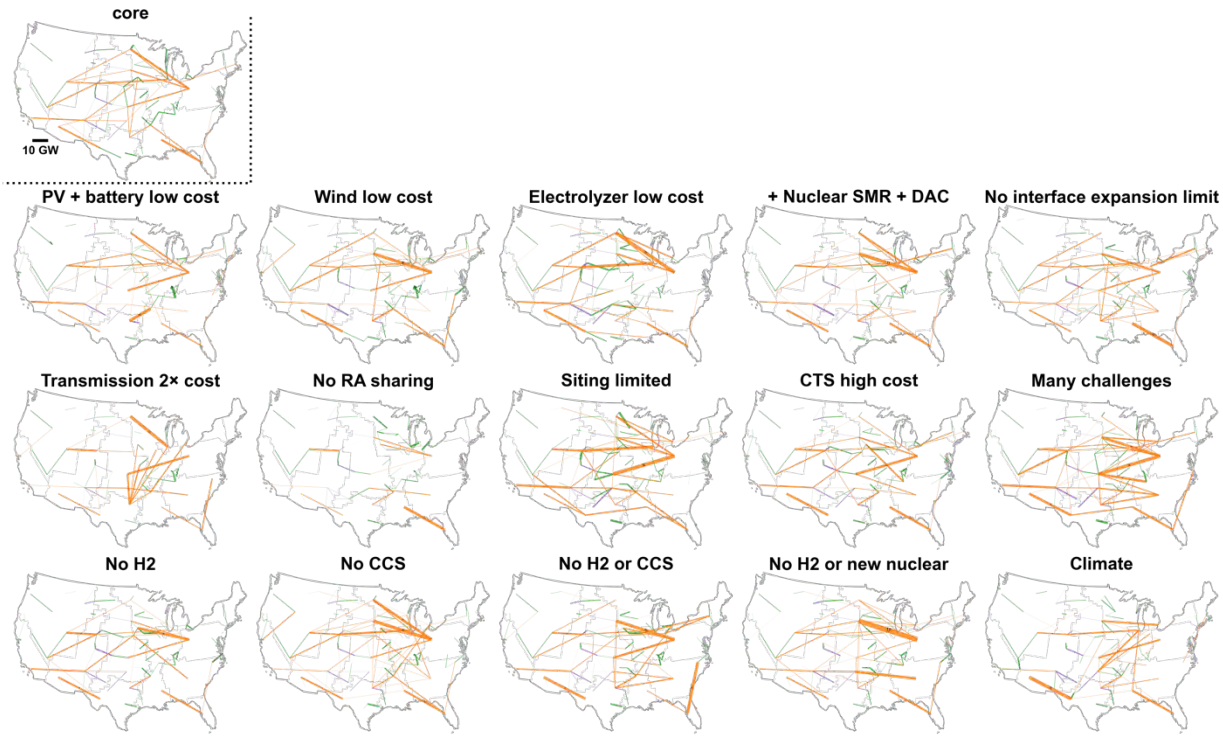


Figure D-6. New long-distance transmission additions through 2050 with Mid-Demand 90% by 2035 assumptions for each sensitivity case under the P2P transmission framework

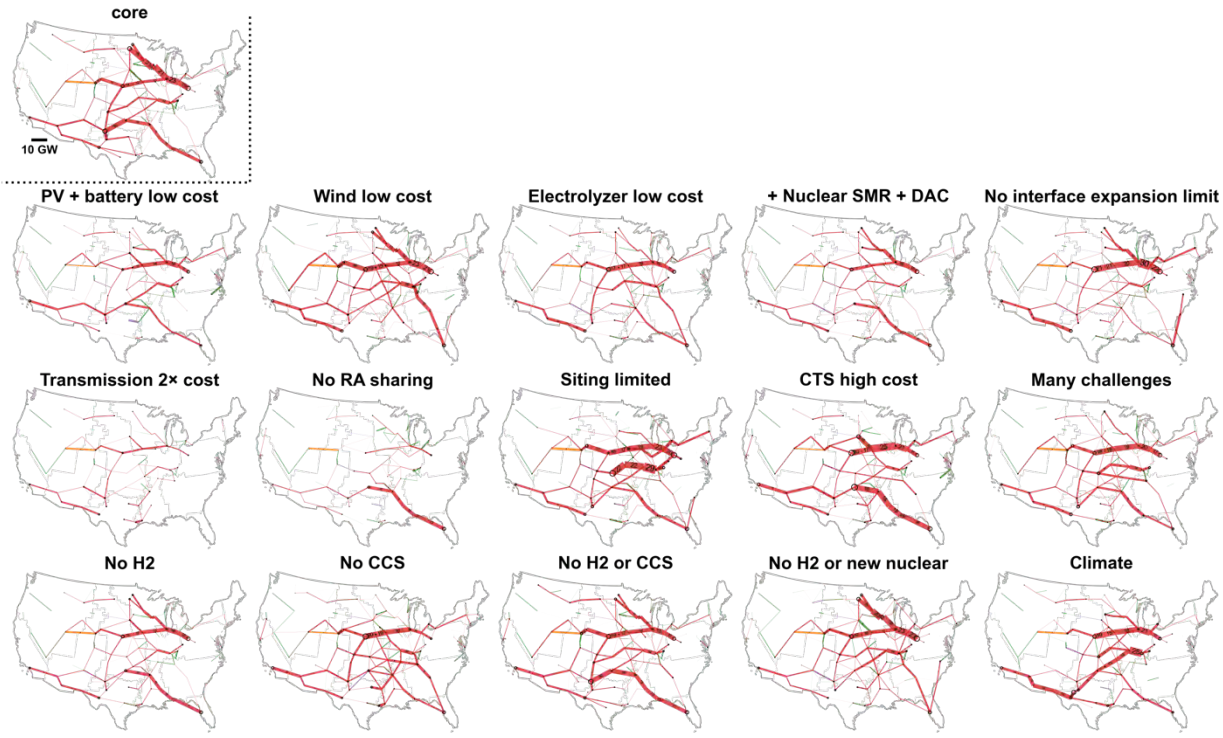


Figure D-7. New long-distance transmission additions through 2050 with Mid-Demand 90% by 2035 assumptions for each sensitivity case under the MT transmission framework

D.2 Additional Capacity Expansion Modeling Results Through 2050

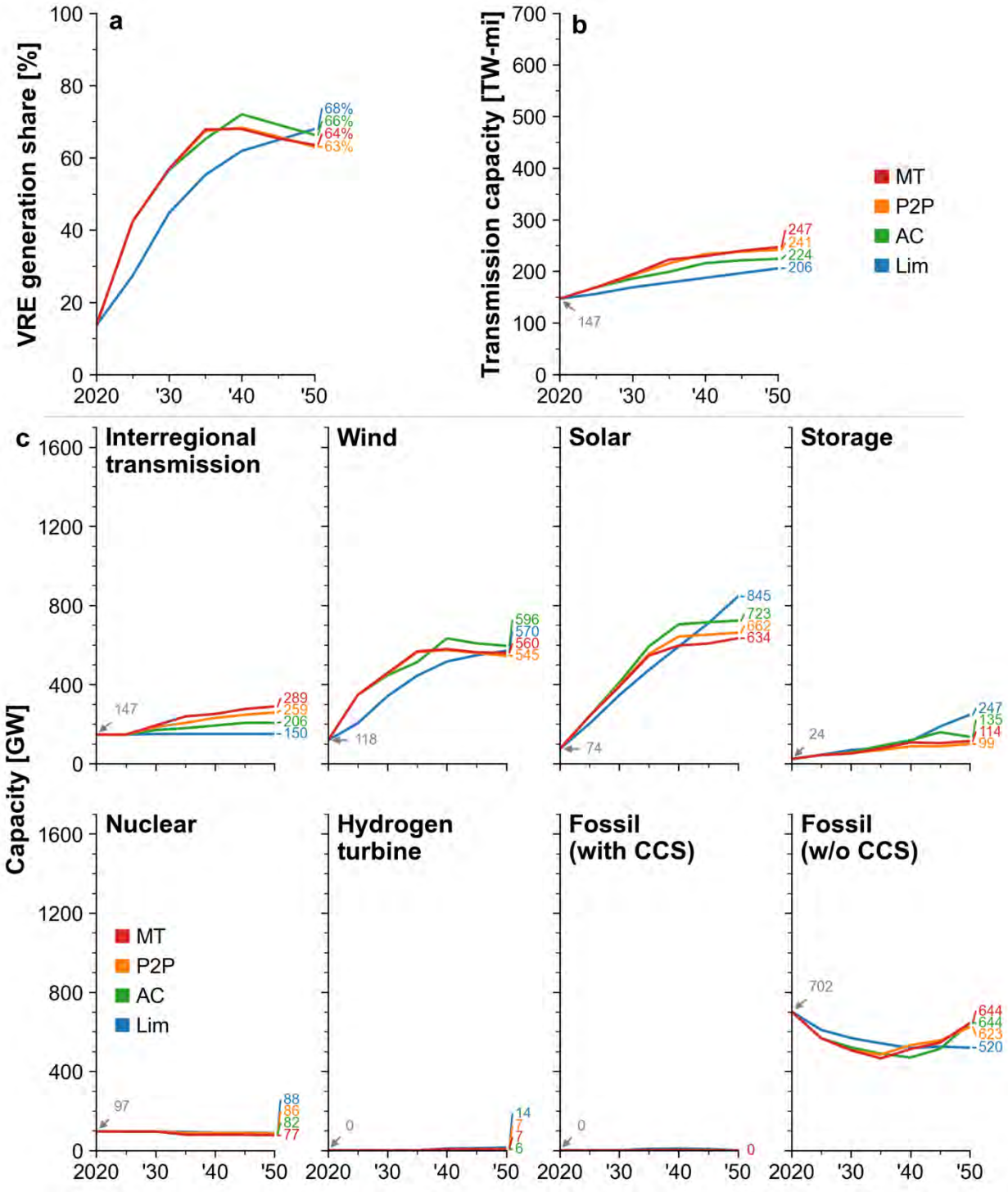


Figure D-8. Trajectories of VRE share (a), transmission capacity (b), and nameplate capacity (c) under Low-Demand Current Policies conditions

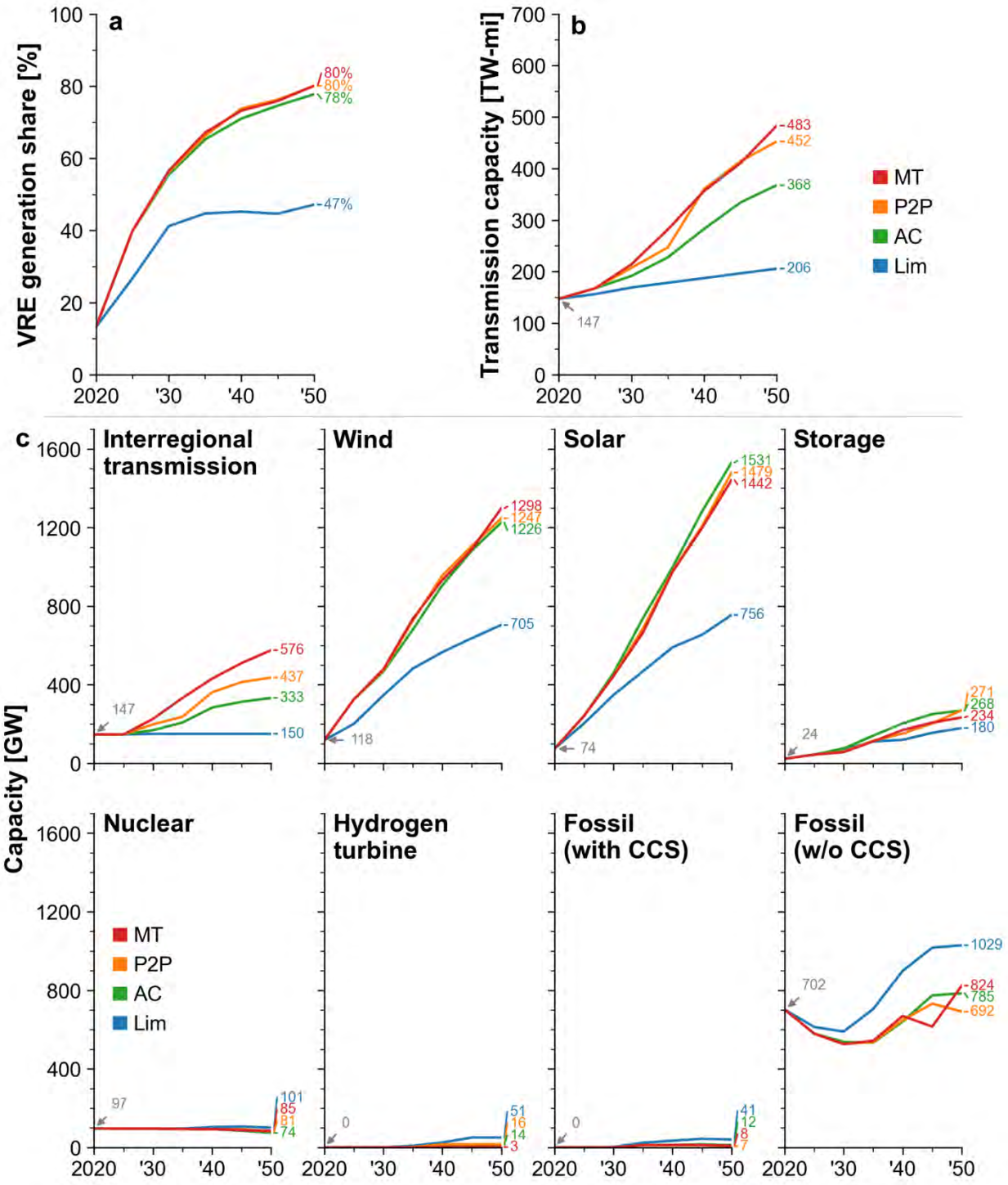


Figure D-9. Trajectories of VRE share (a), transmission capacity (b), and nameplate capacity (c) under High-Demand Current Policies conditions

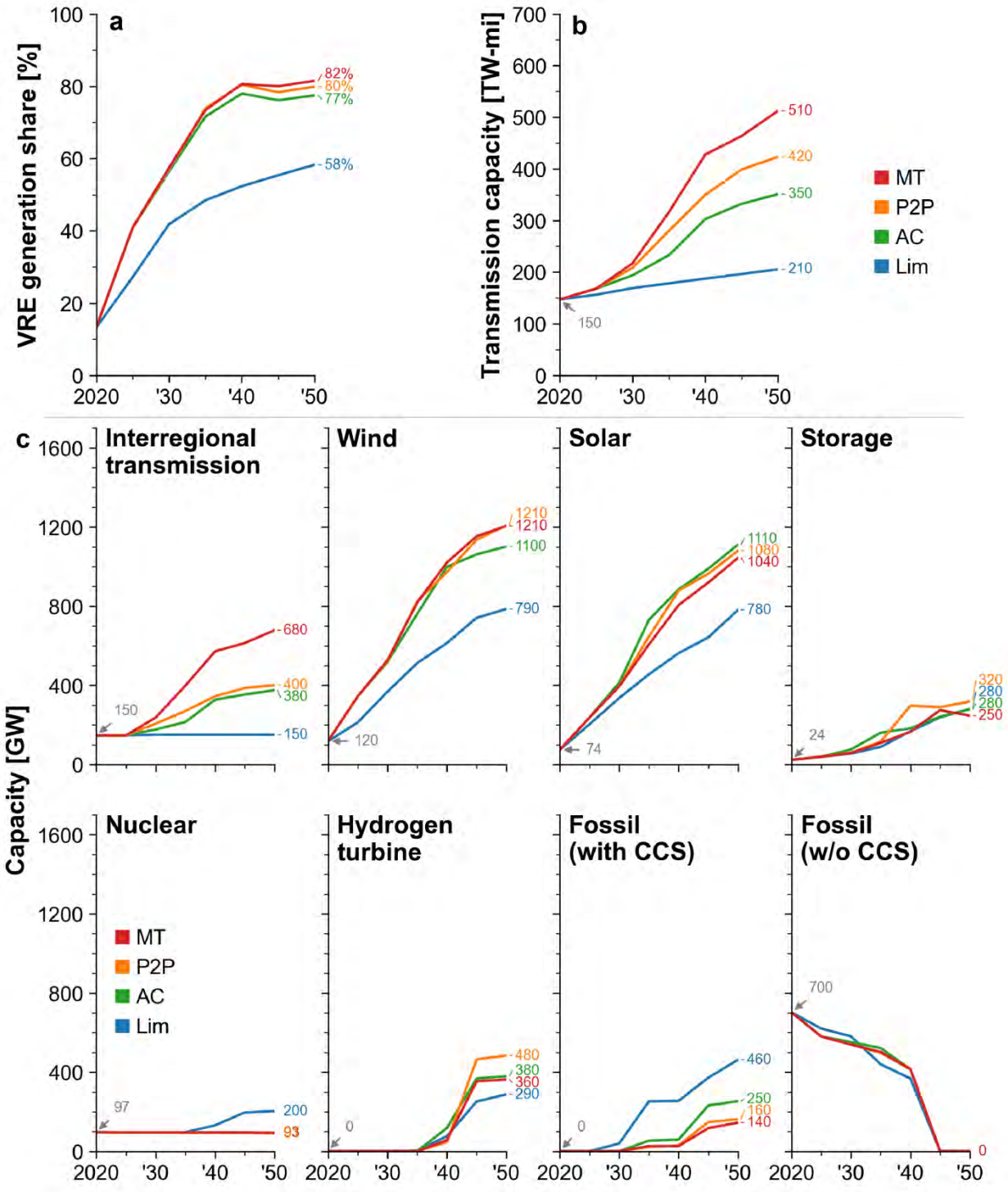


Figure D-10. Trajectories of VRE share (a), transmission capacity (b), and nameplate capacity (c) under Mid-Demand 90% by 2035 conditions

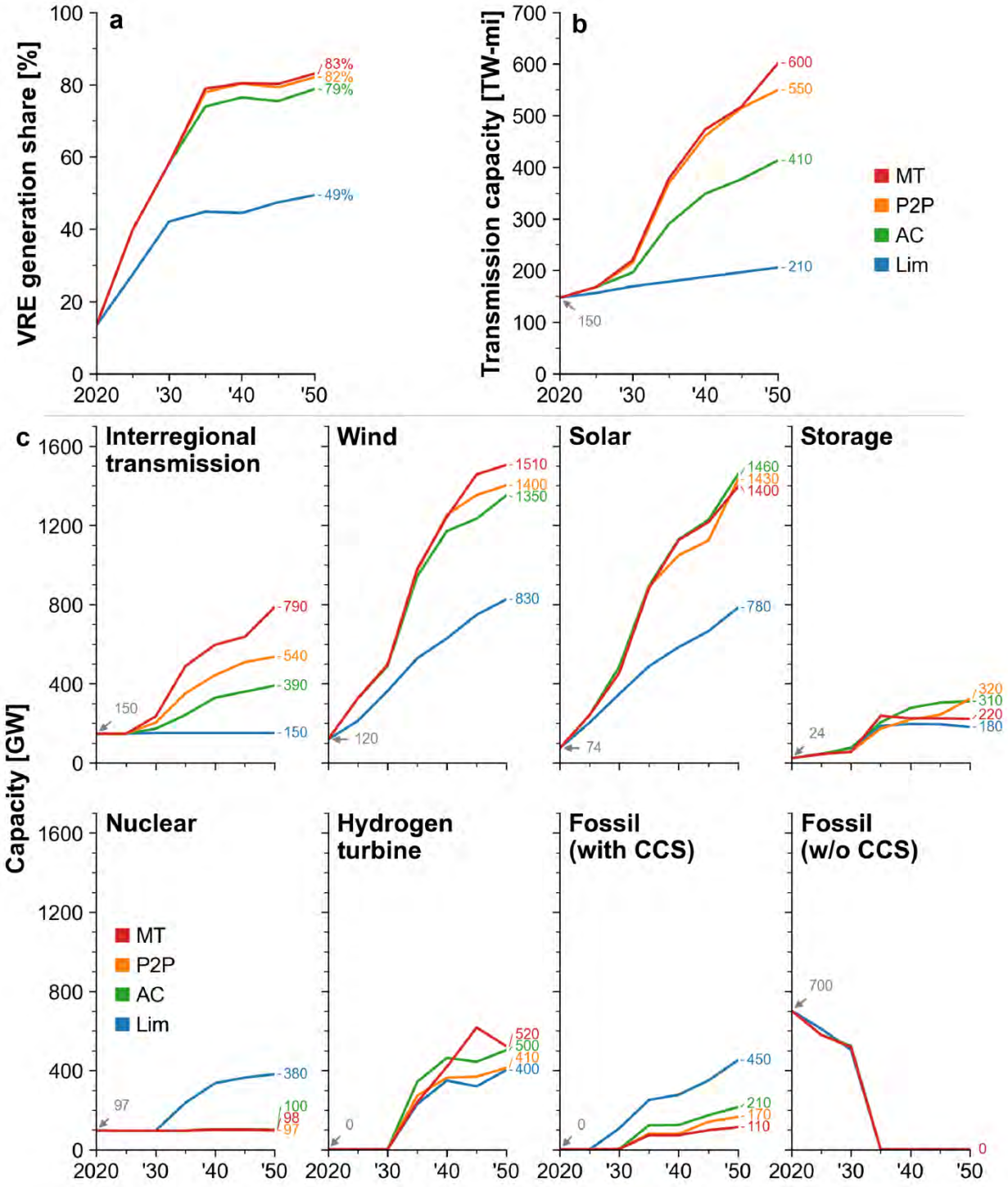


Figure D-11. Trajectories of VRE share (a), transmission capacity (b), and nameplate capacity (c) under High-Demand 100% by 2035 conditions

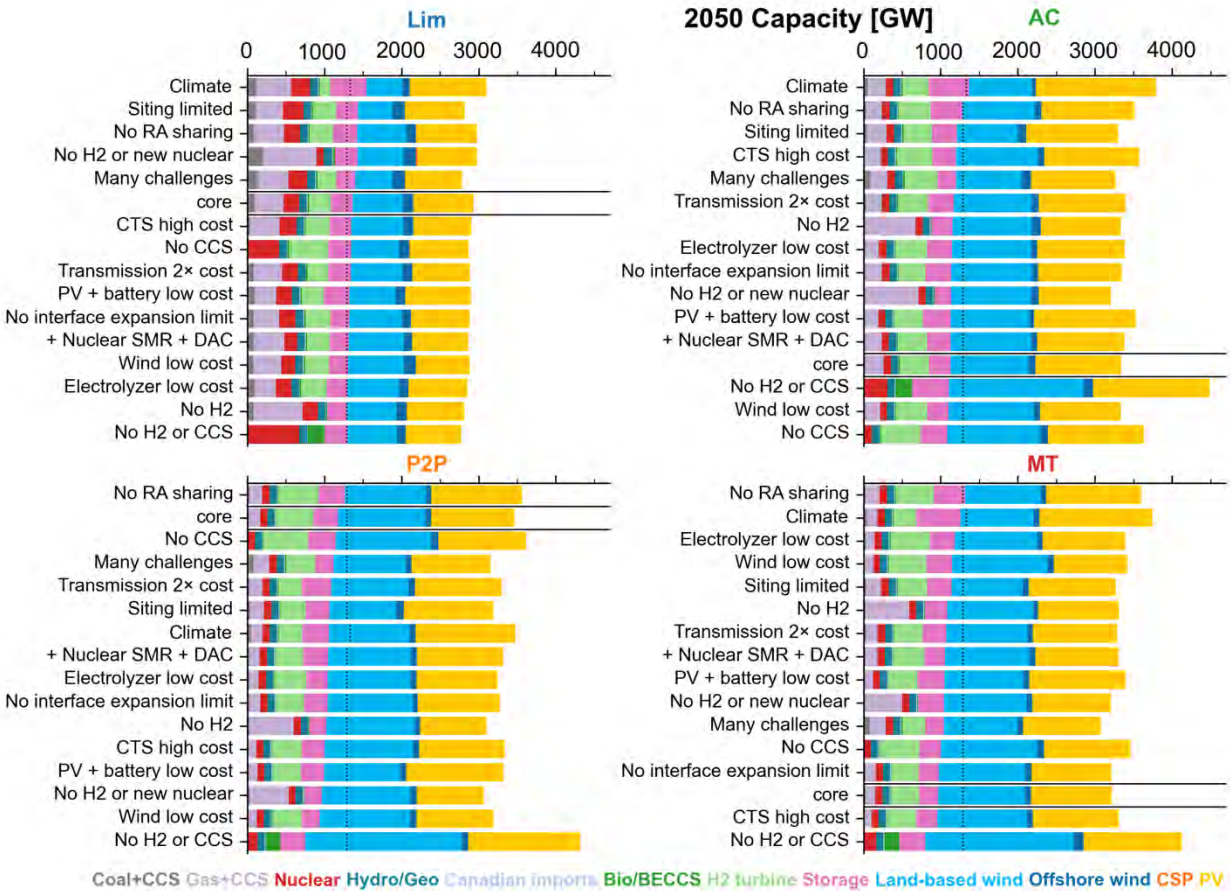


Figure D-12. National capacity mix in 2050 with Mid-Demand 90% by 2035 assumptions for each transmission framework and sensitivity case

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.

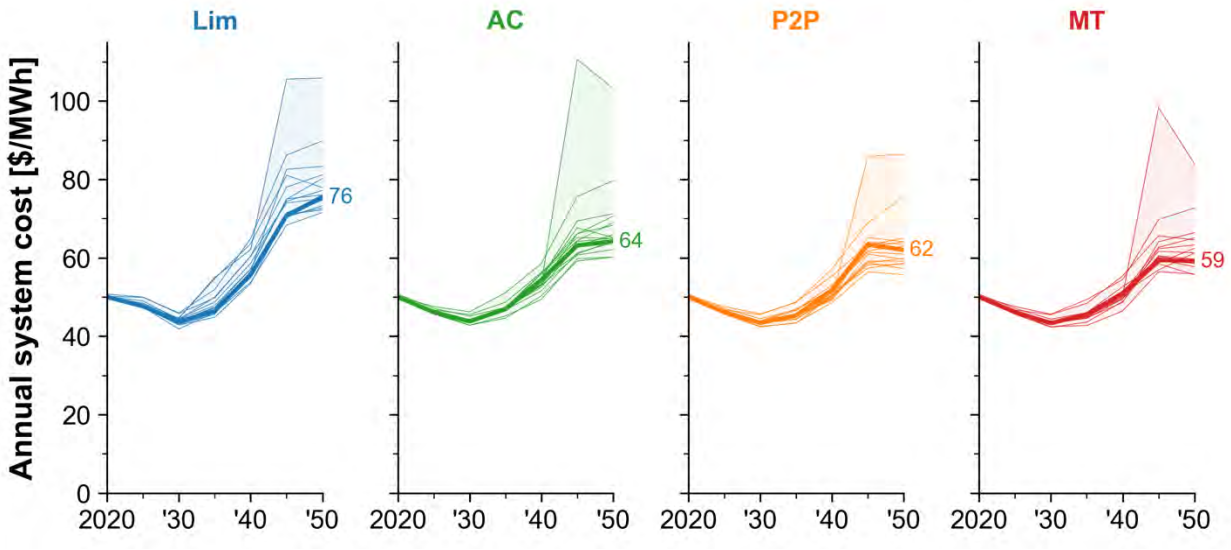


Figure D-13. Annual system cost ($/MWh) for the four transmission frameworks and all sensitivity cases under Mid-Demand 90% by 2035 conditions

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).

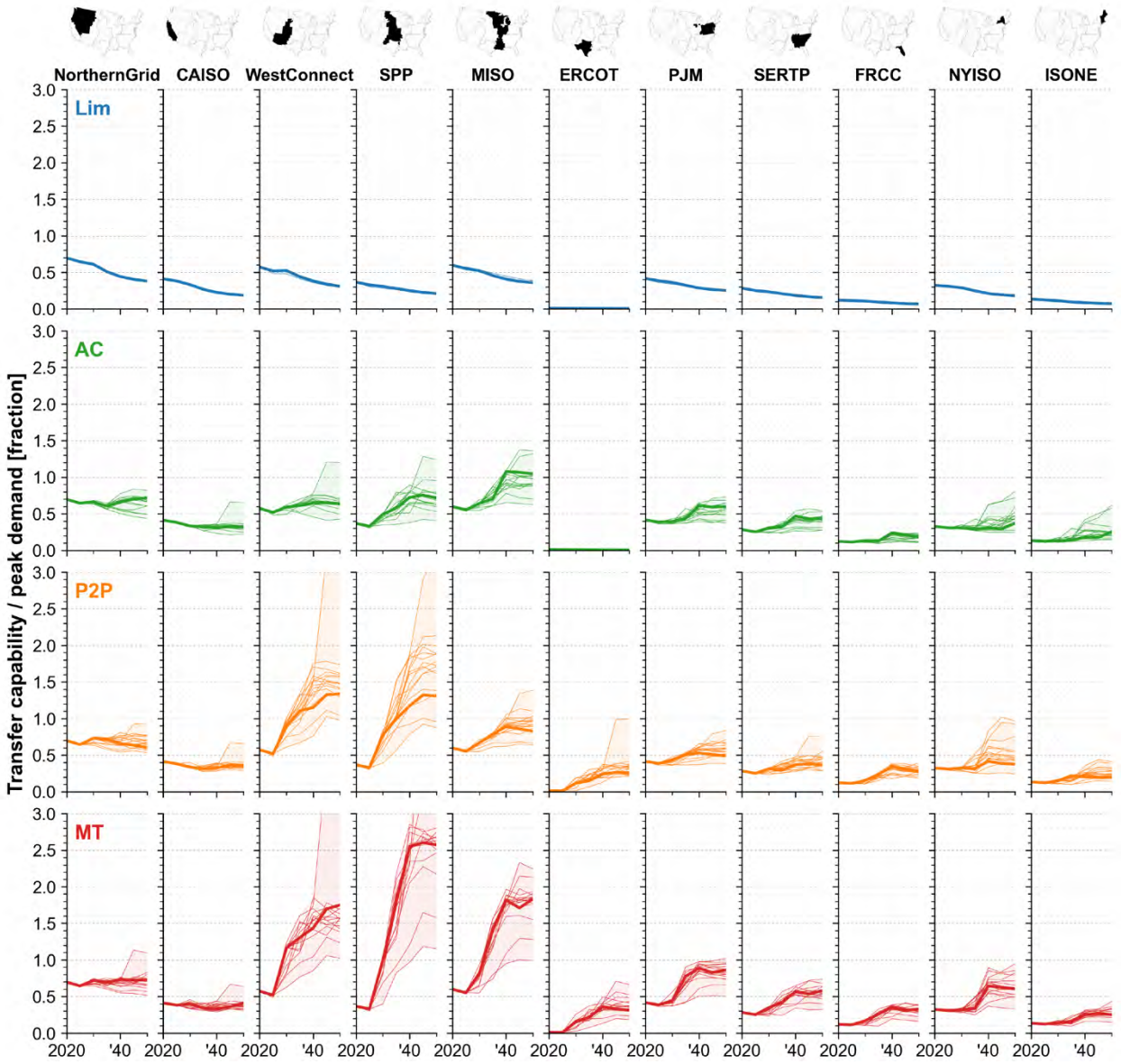


Figure D-14. Ratio of interregional transfer capability to peak demand for the 11 planning regions with Mid-Demand 90% by 2035 assumptions across the four transmission frameworks and all sensitivity cases

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.

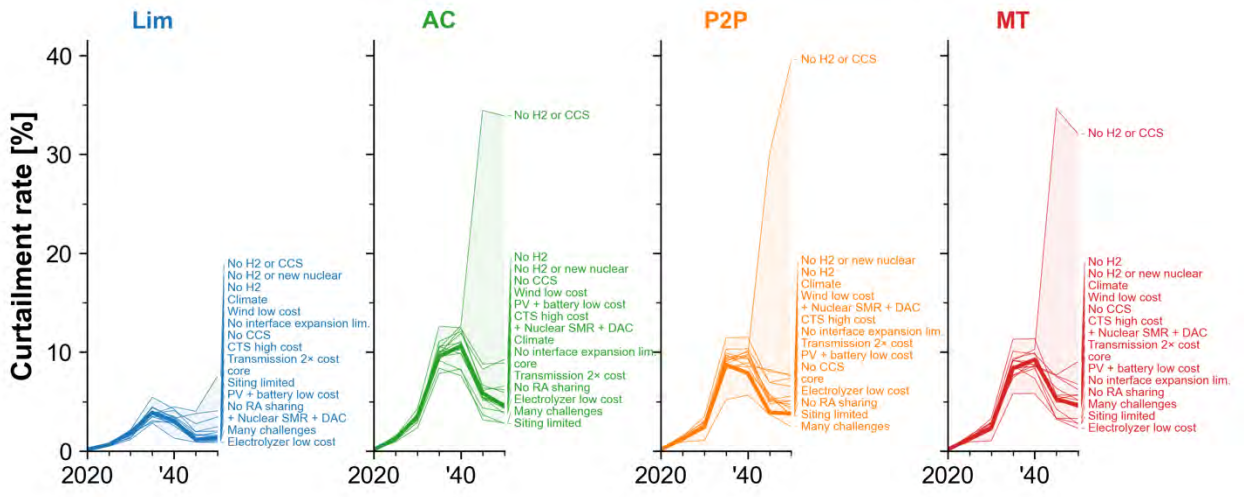


Figure D-15. National average VRE curtailment rate [$MWh_{curtailed}$ / $MWh_{available}$] with Mid-Demand 90% by 2035 assumptions for all sensitivity cases

D.3 Additional Resource Adequacy Results

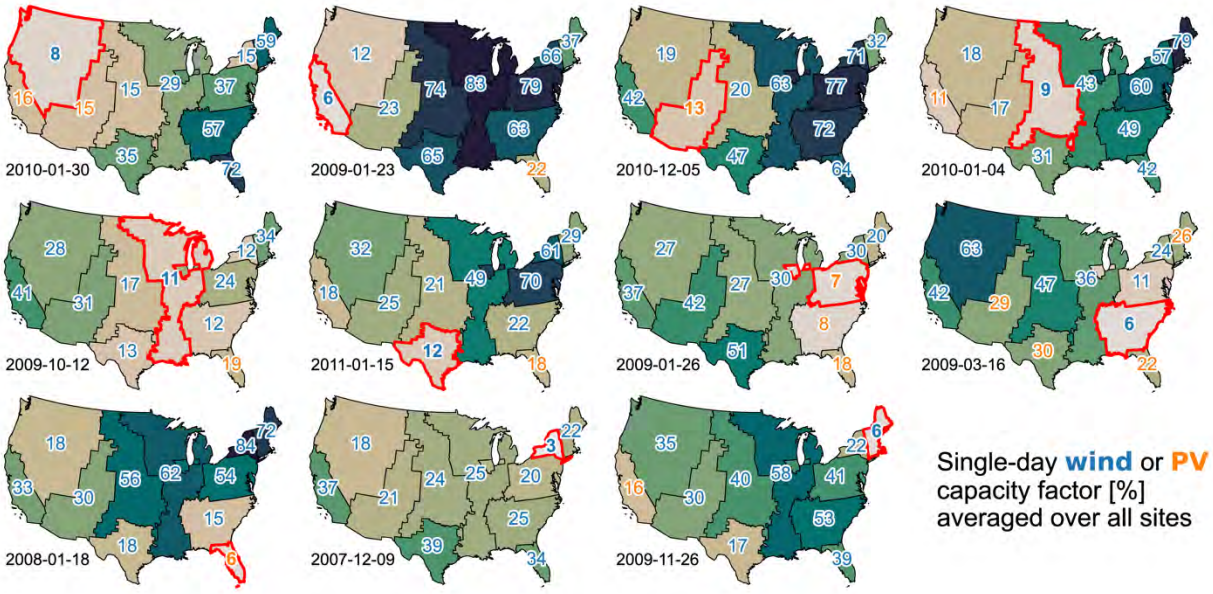


Figure D-16. Single-day wind (blue) or PV (orange) capacity factor on the least-windy/sunny day from 2007 to 2013 weather years in each planning region

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.

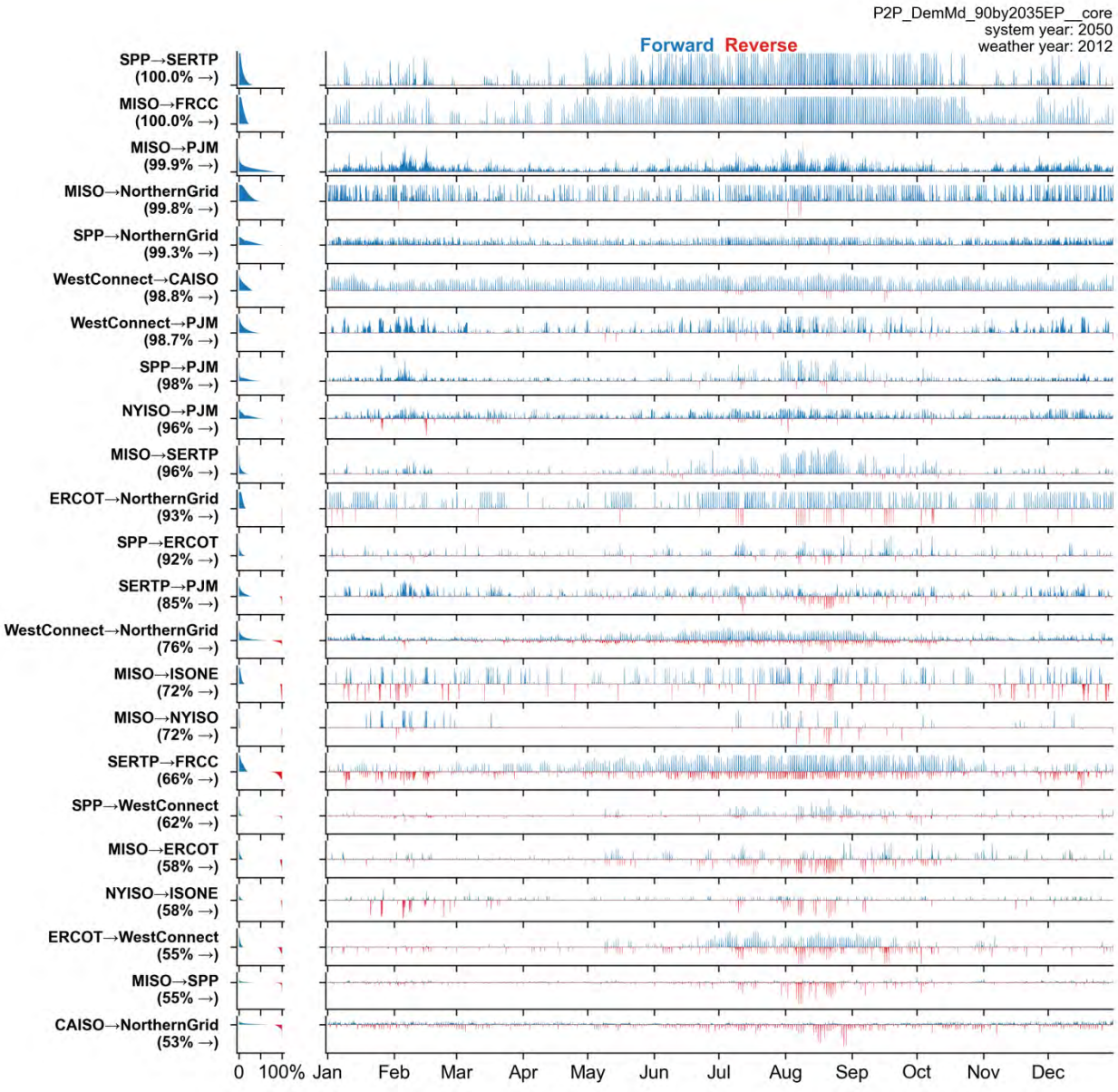


Figure D-17. Hourly interregional transmission flows for the P2P transmission framework in 2050 under Mid-Demand 90% by 2035 conditions as modeled by PRAS

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.

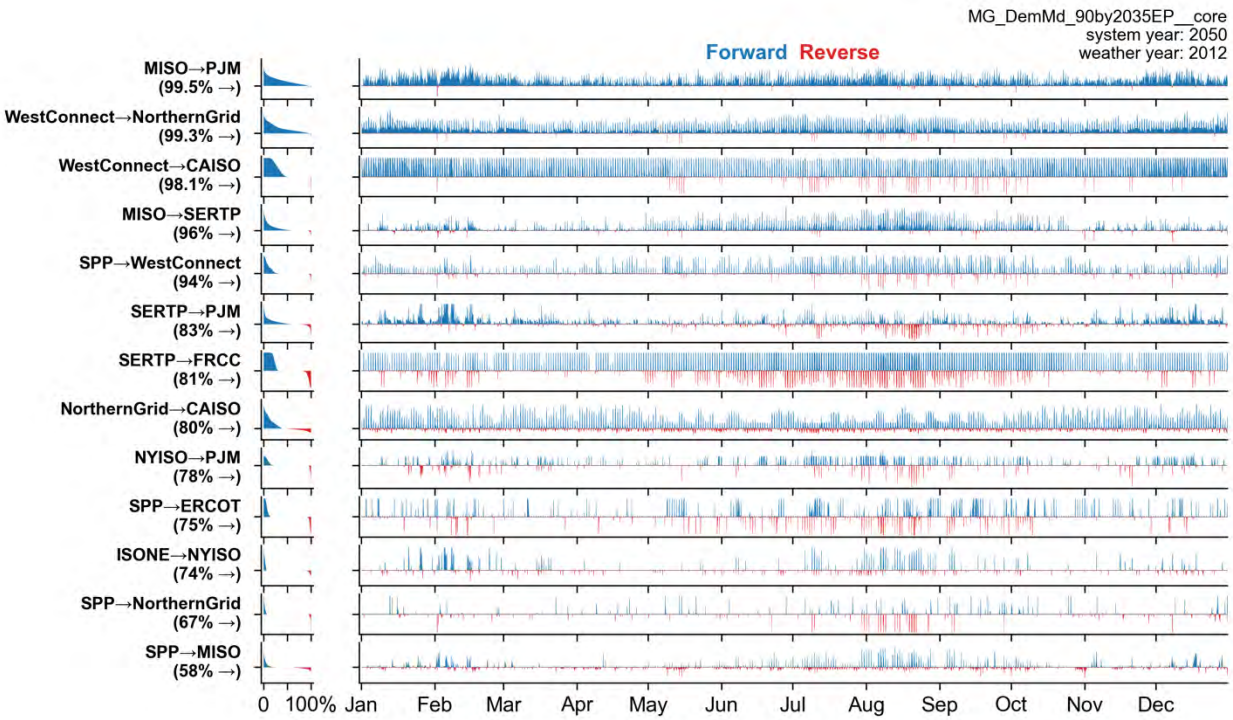


Figure D-18. Hourly interregional transmission flows for the MT transmission framework in 2050 under Mid-Demand 90% by 2035 conditions as modeled by PRAS

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

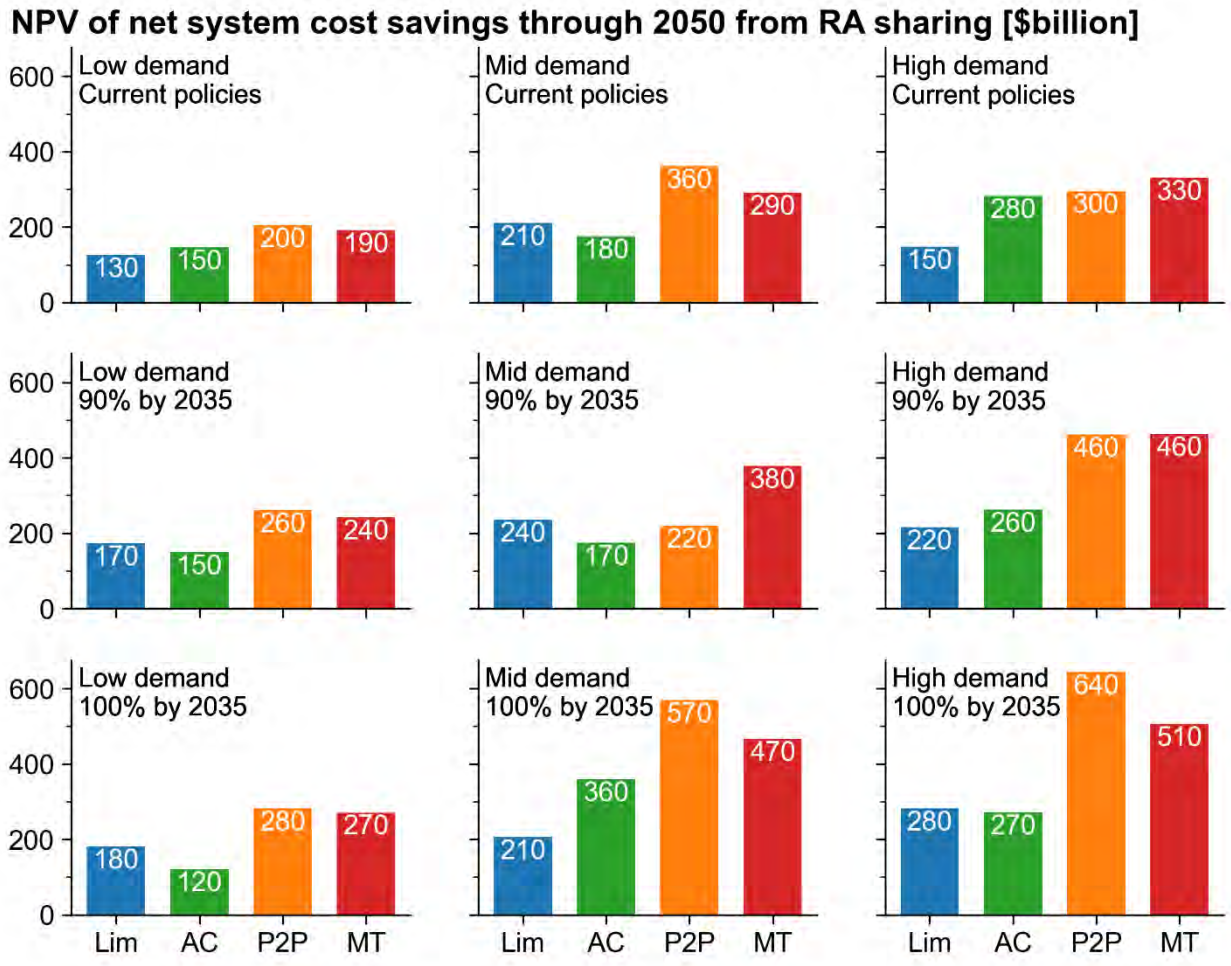


Figure D-19. Impact of the allowance of interregional RA sharing on system cost for each of the demand and emissions assumptions

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

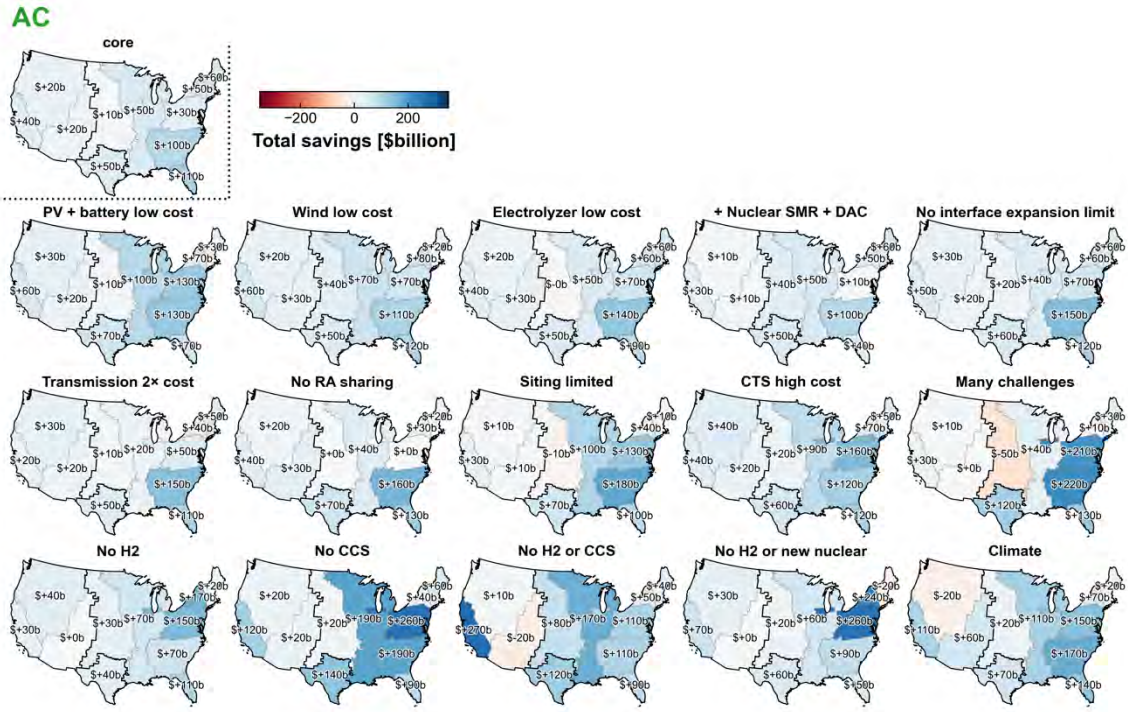


Figure D-20. Net present value of system savings in the AC transmission framework by region in $billion of avoided costs relative to the Limited framework under Mid-Demand 90% by 2035 scenario assumptions

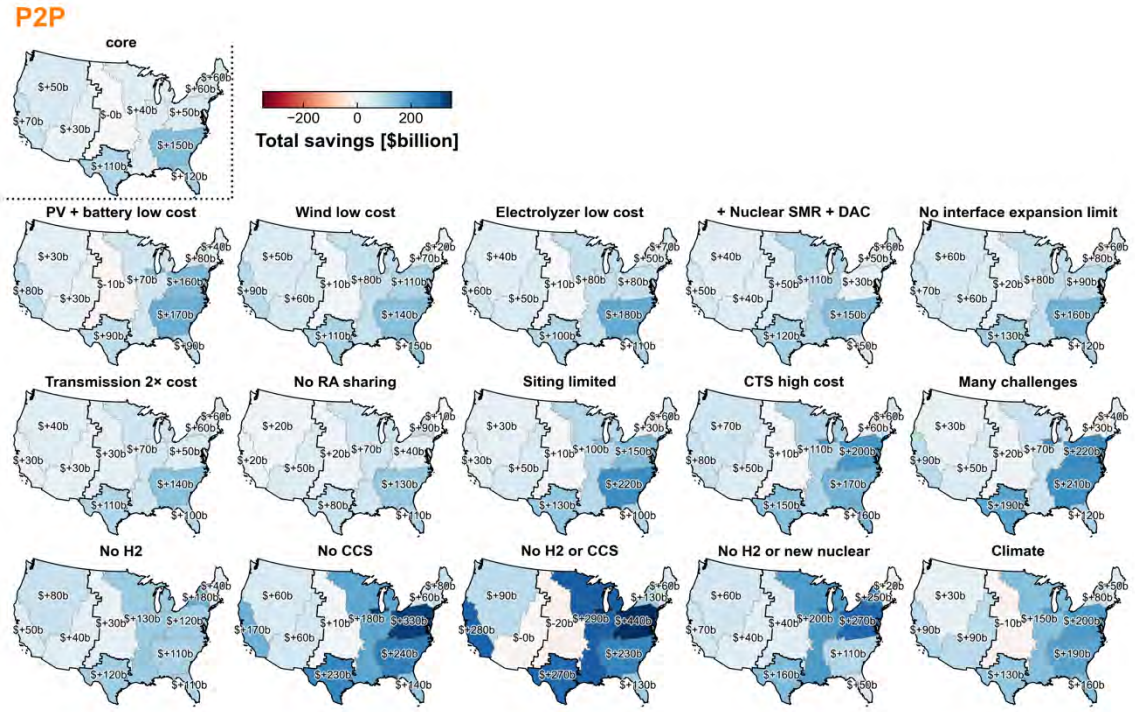


Figure D-21. Net present value of system savings in the P2P transmission framework by region in $billion of avoided costs relative to the Limited framework under Mid-Demand 90% by 2035 scenario assumptions

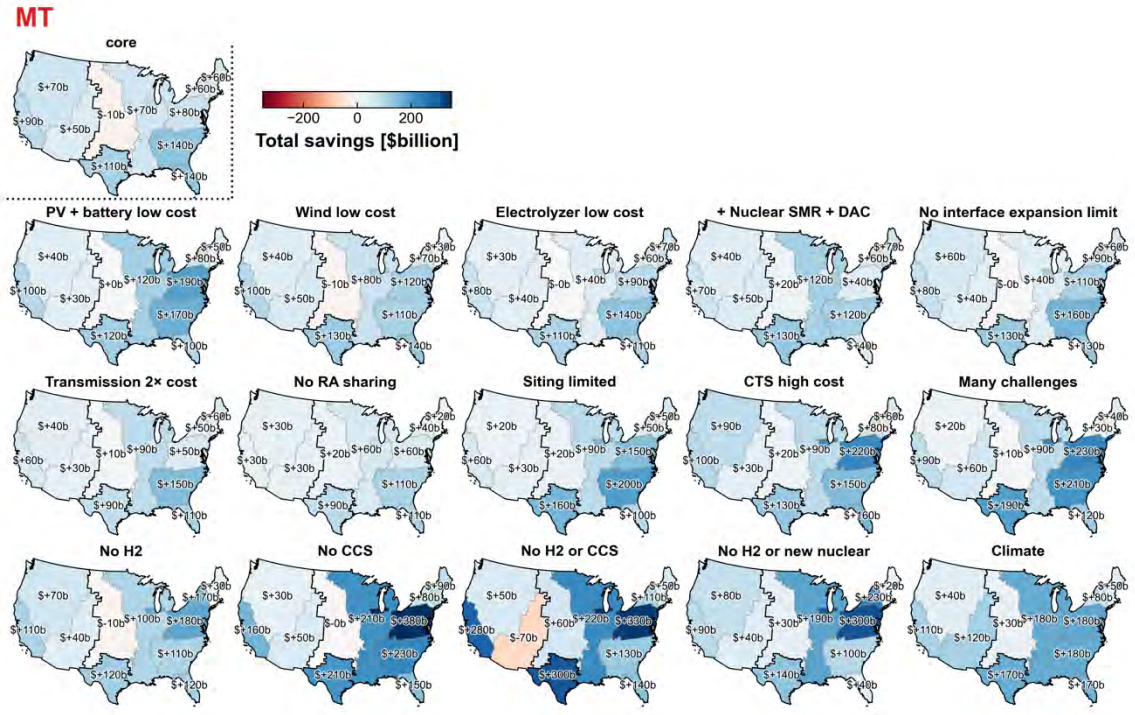


Figure D-22. Net present value of system savings in the MT transmission framework by region in $billion of avoided costs relative to the Limited framework under Mid-Demand 90% by 2035 scenario assumptions

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.

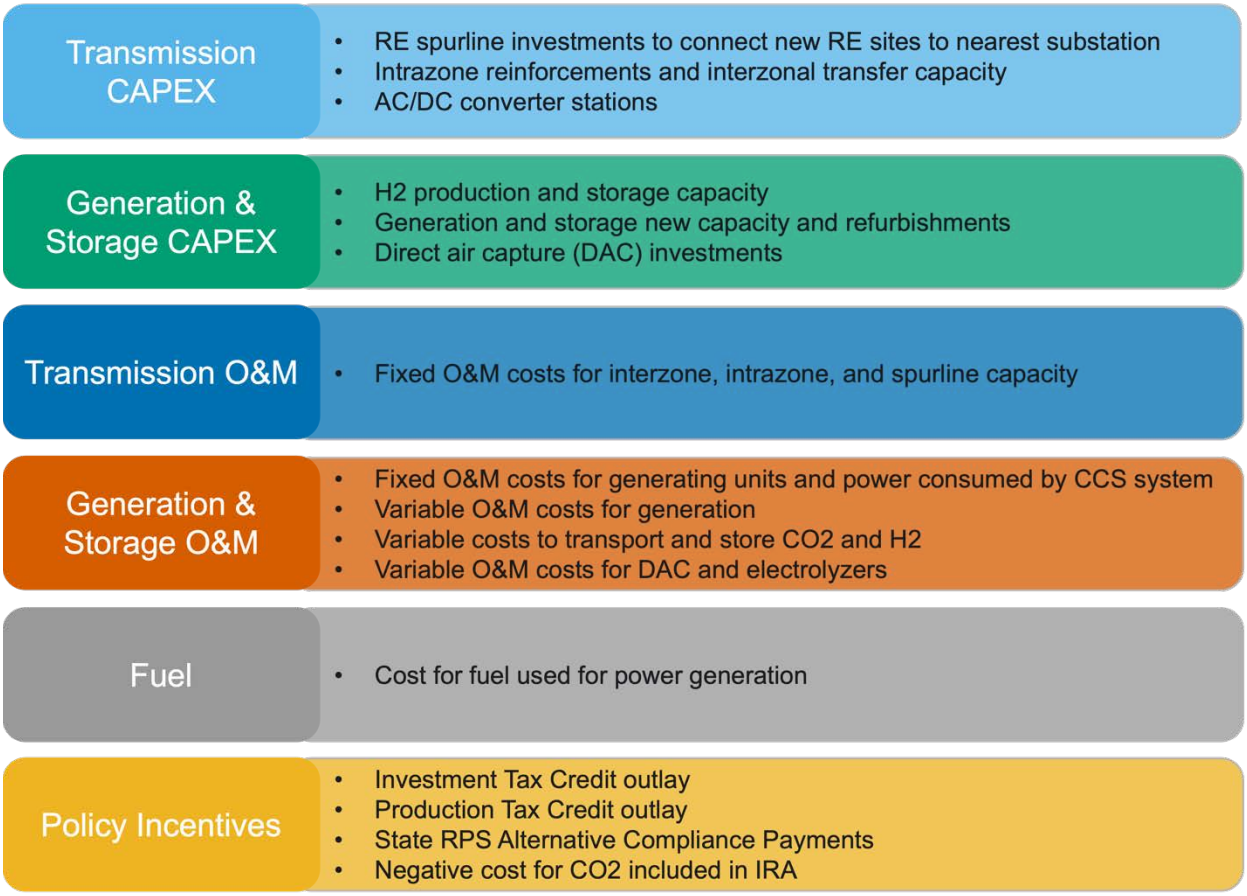


Figure E-1. System costs included in transmission valuation. Many benefits are correlated and not mutually exclusive.

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.

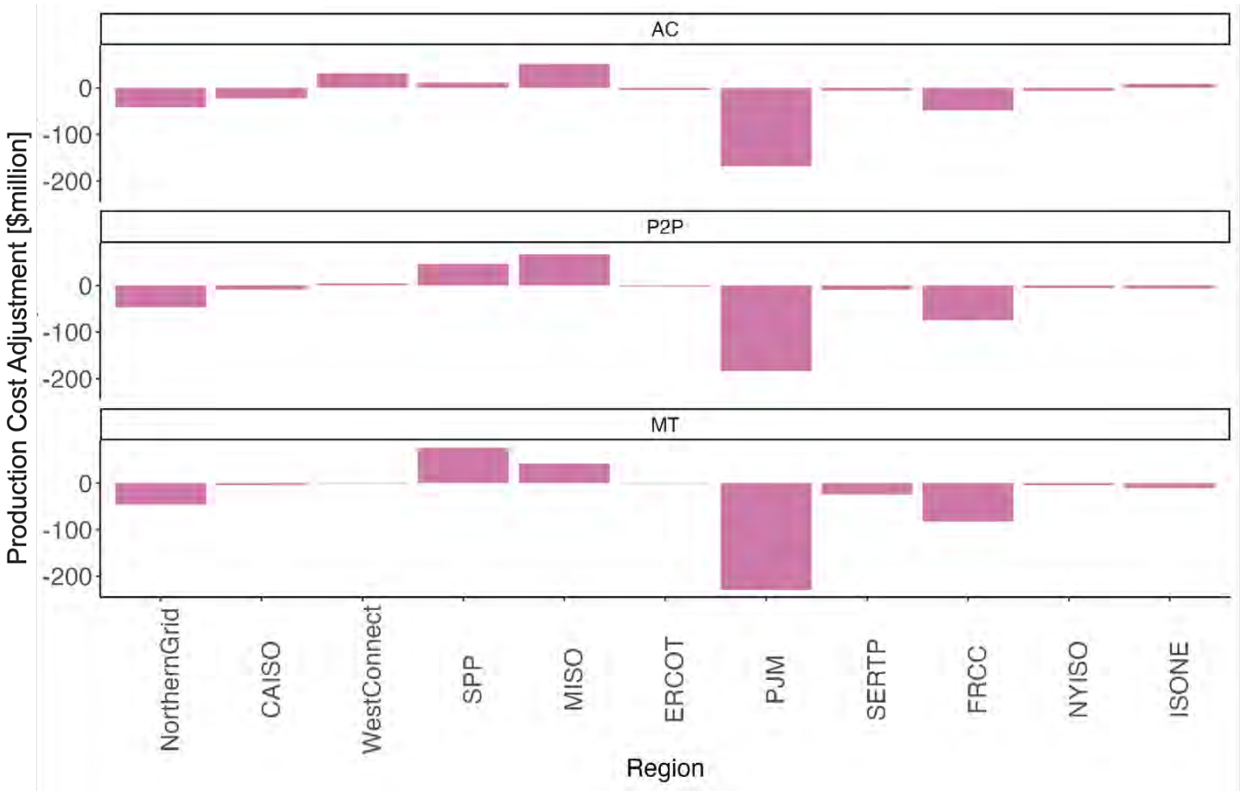


Figure E-2. Production cost adjustment for each transmission planning region and network topology for the core Mid-Demand 90% by 2035 scenarios ($million)

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)

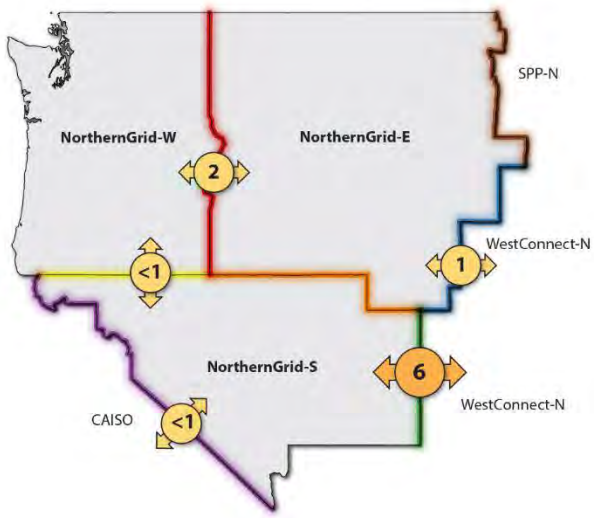
REGION	EXISTING	Percentile of New Capacity 25TH	50TH	75TH
Northern Grid S.	11	0	0.1	0.4
West Connect S.	5.3	3.0	4.1	4.9



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

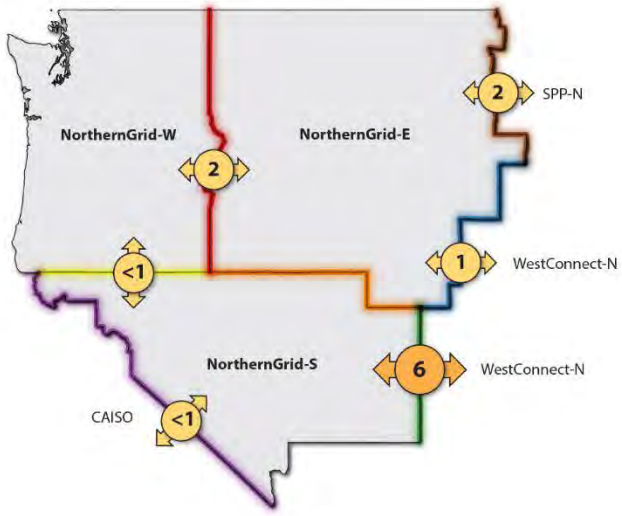


NorthernGrid

AC Framework

Interface Capacity (GW)

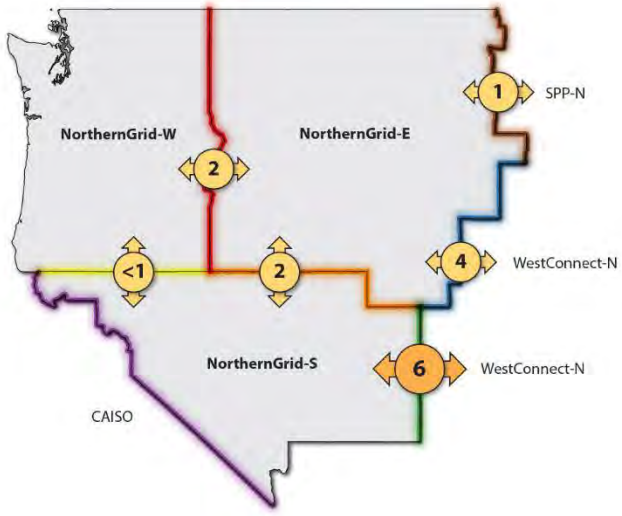
REGION	EXISTING	Percentile of New Capacity 25TH	50TH	75TH
NG-W, NG-E	13.2	1.7	1.7	1.7
NG-E, SPP-N	0.2	0	0	0
NG-E, WC-N	4.0	1.1	1.2	1.8
NG-E, NG-S	3.1	0	0	0.6
NG-W, NG-S	0.5	0.1	0.4	1.2
NG-S, WC-N	2.4	6.3	7.1	7.2
NG-S, CAISO	11	0.1	0.7	1.4



P2P Framework

Interface Capacity (GW)

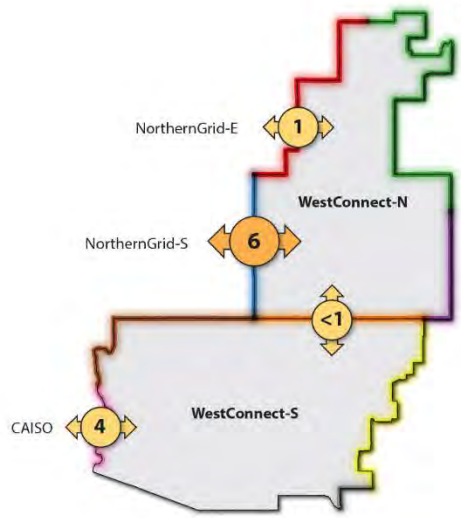
REGION	EXISTING	Percentile of New Capacity 25TH	50TH	75TH
NG-W, NG-E	13.2	1.7	1.7	1.7
NG-E, SPP-N	0.2	1.8	2.2	2.5
NG-E, WC-N	4.0	1.4	2.1	2.5
NG-E, NG-S	3.1	0	0	0
NG-W, NG-S	0.5	0.1	0.3	0.5
NG-S, WC-N	2.4	5.8	7.0	7.9
NG-S, CAISO	11	0.1	0.4	0.3



MT Framework

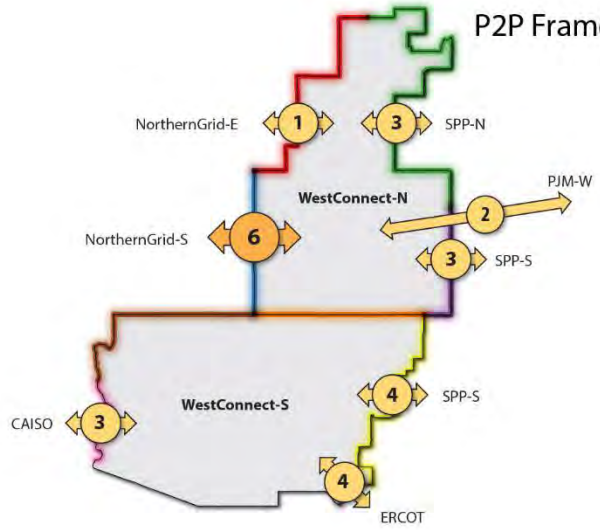
Interface Capacity (GW)

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



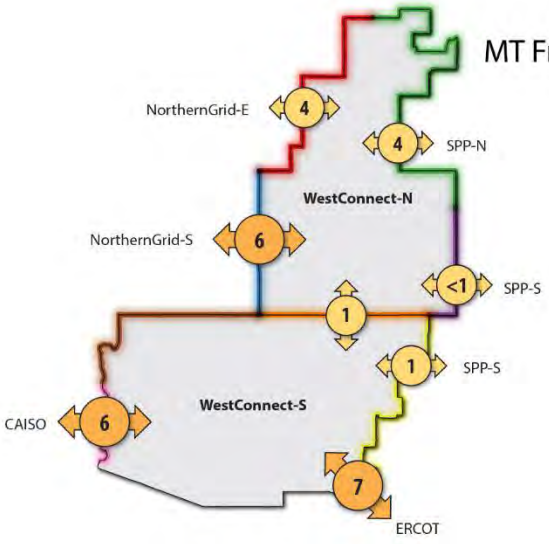
Interface Capacity (GW)

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

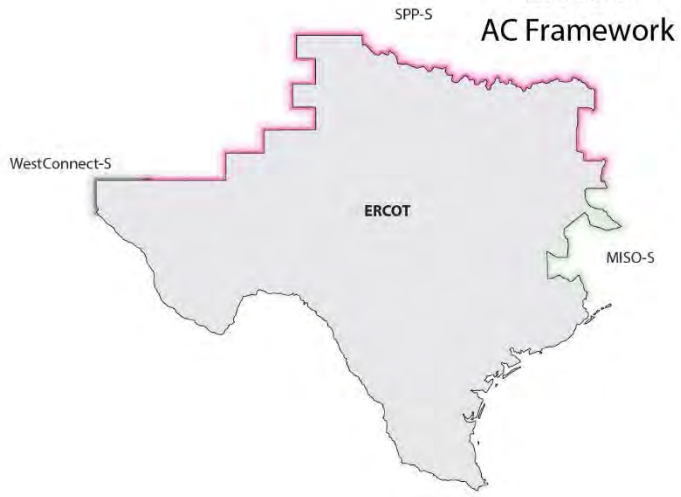


Interface Capacity (GW)

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

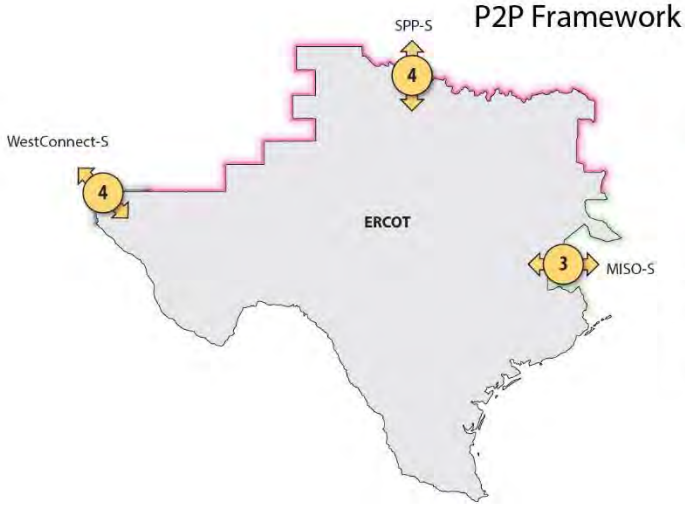
AC Framework



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

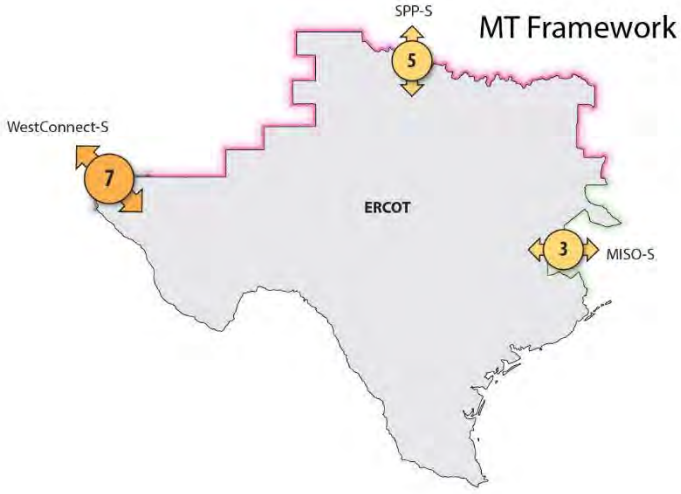
P2P Framework



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

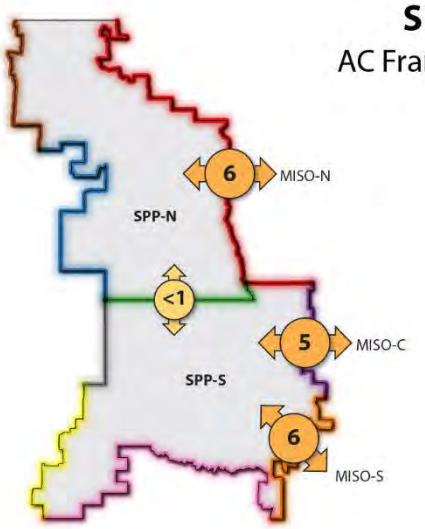


Interface Capacity (GW)

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

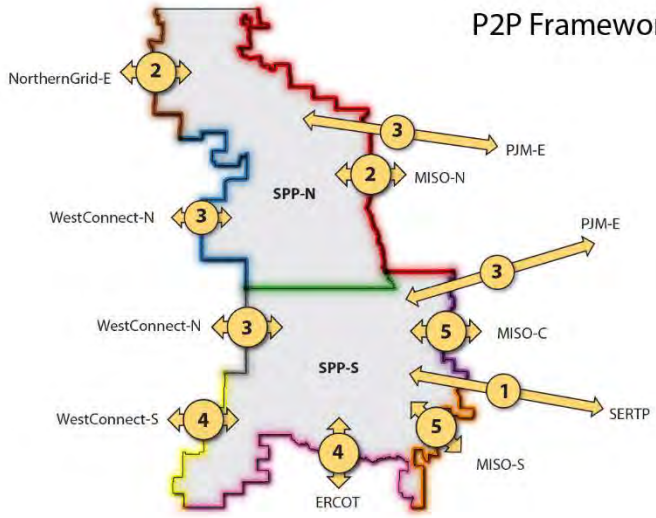
AC Framework



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

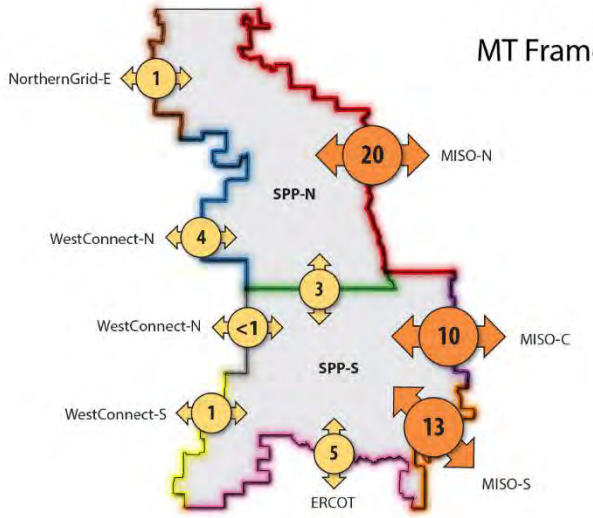
P2P Framework



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

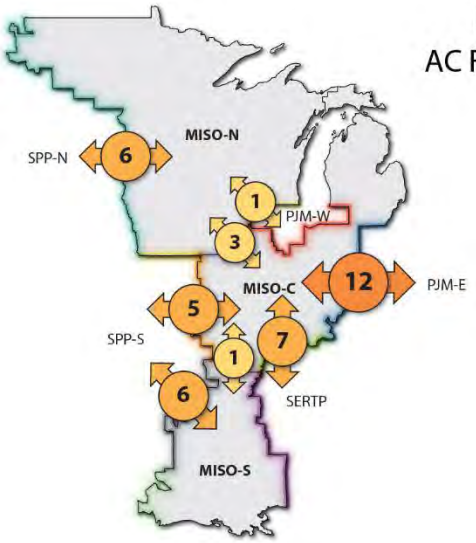


Interface Capacity (GW)

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

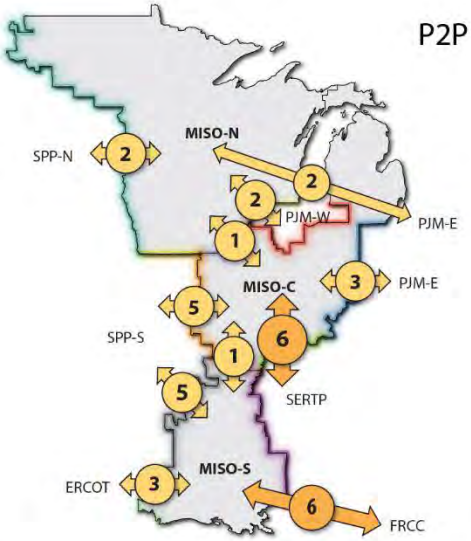
AC Framework



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

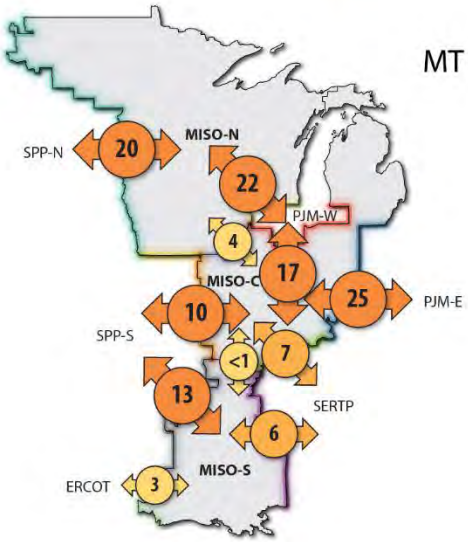
P2P Framework



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
MISO-S, FRCC	0	6.2	7.3	8.6

MT Framework

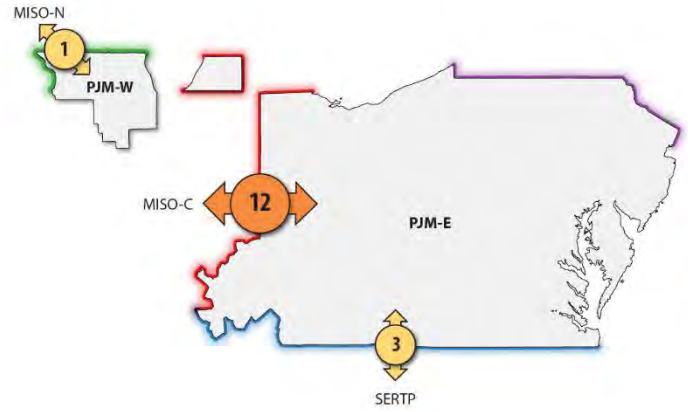


Interface Capacity (GW)

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

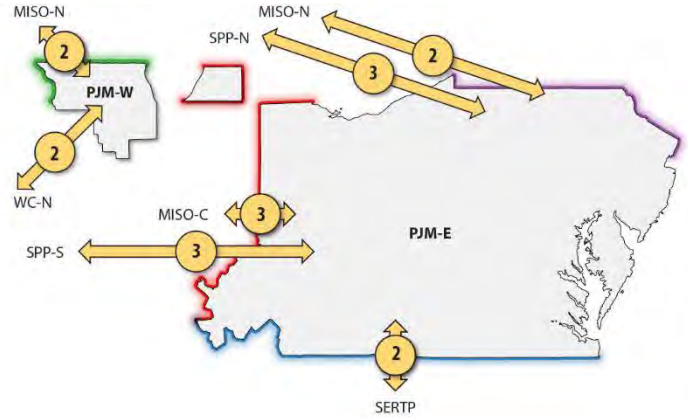
AC Framework



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

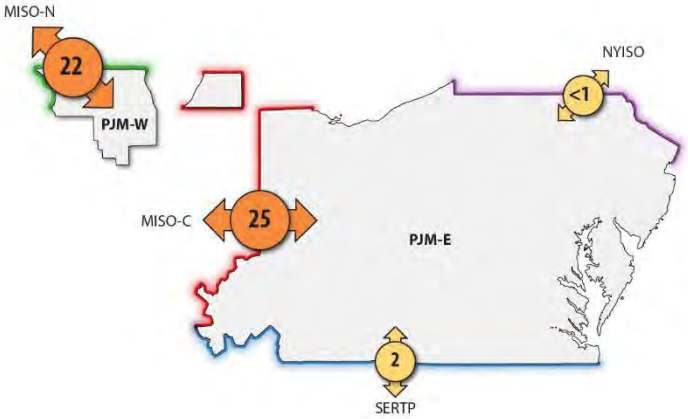
P2P Framework



Interface Capacity (GW)

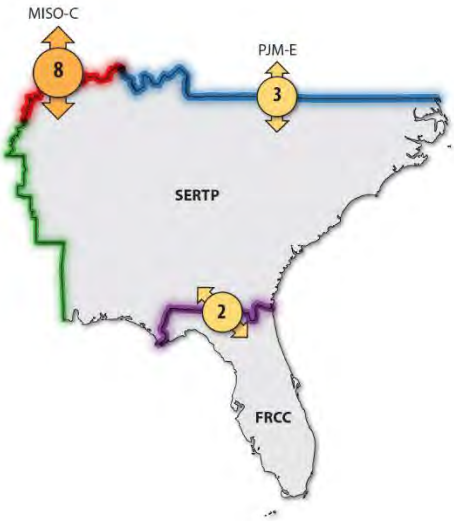
REGION	EXISTING	Percentile of New Capacity 25TH	50TH	75TH
PJM-W, MISO-N	5.0	1.5	2.0	3.4
PJM-E, MISO-C	28.3	2.6	4.7	7.9
PJM-E, SERTP	10.9	2.2	5.0	6.3
PJM-E, NYISO	6.6	0	0	0
Nonadjacent Region Interfaces				
PJM-E, MISO-N	0	2.0	4.4	7.1
PJM-E, SPP-N	0	3.4	5.2	10.0
PJM-E, SPP-S	0	3.3	4.7	7.1
PJM-W, WC-N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

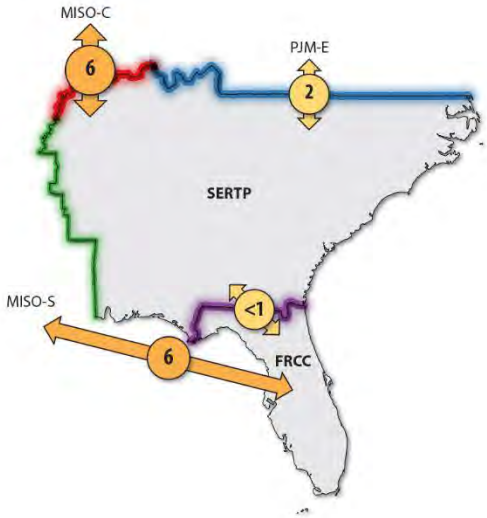


SERTP & FRCC

AC Framework

Interface Capacity (GW)

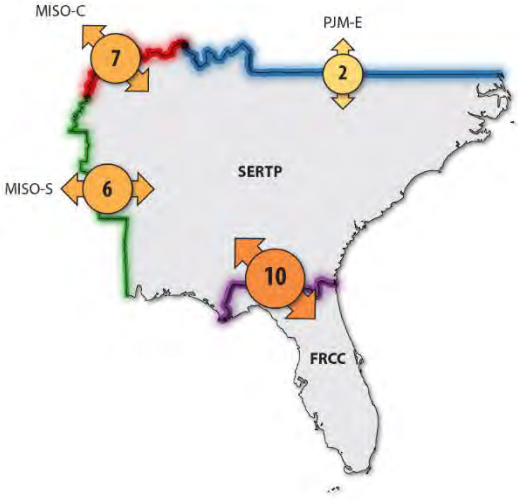
REGION	EXISTING	Percentile of New Capacity 25TH	50TH	75TH
SERTP, MISO-C	4.1	7.5	10.1	12.2
SERTP, PJM-E	10.9	3.2	6.8	7.4
SERTP, MISO-S	11.0	0	0	0.1
SERTP, FRCC	6.6	1.9	2.3	2.6



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

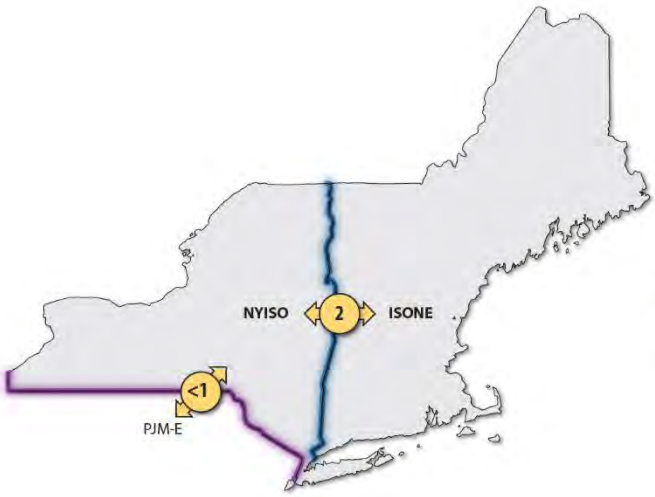
P2P Framework



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









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	)
(MISO)	)
	)

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



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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.

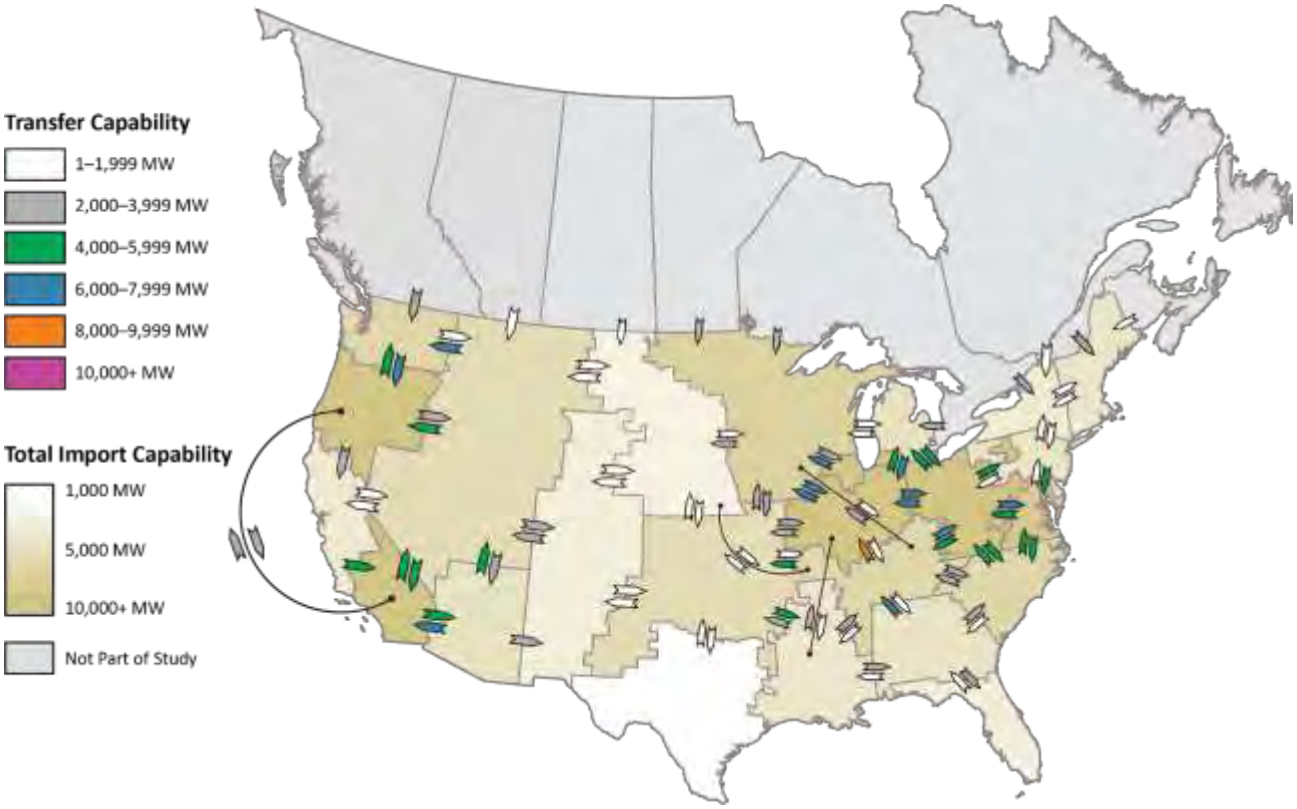

Figure ES.1: Transfer Capabilities (Summer)

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

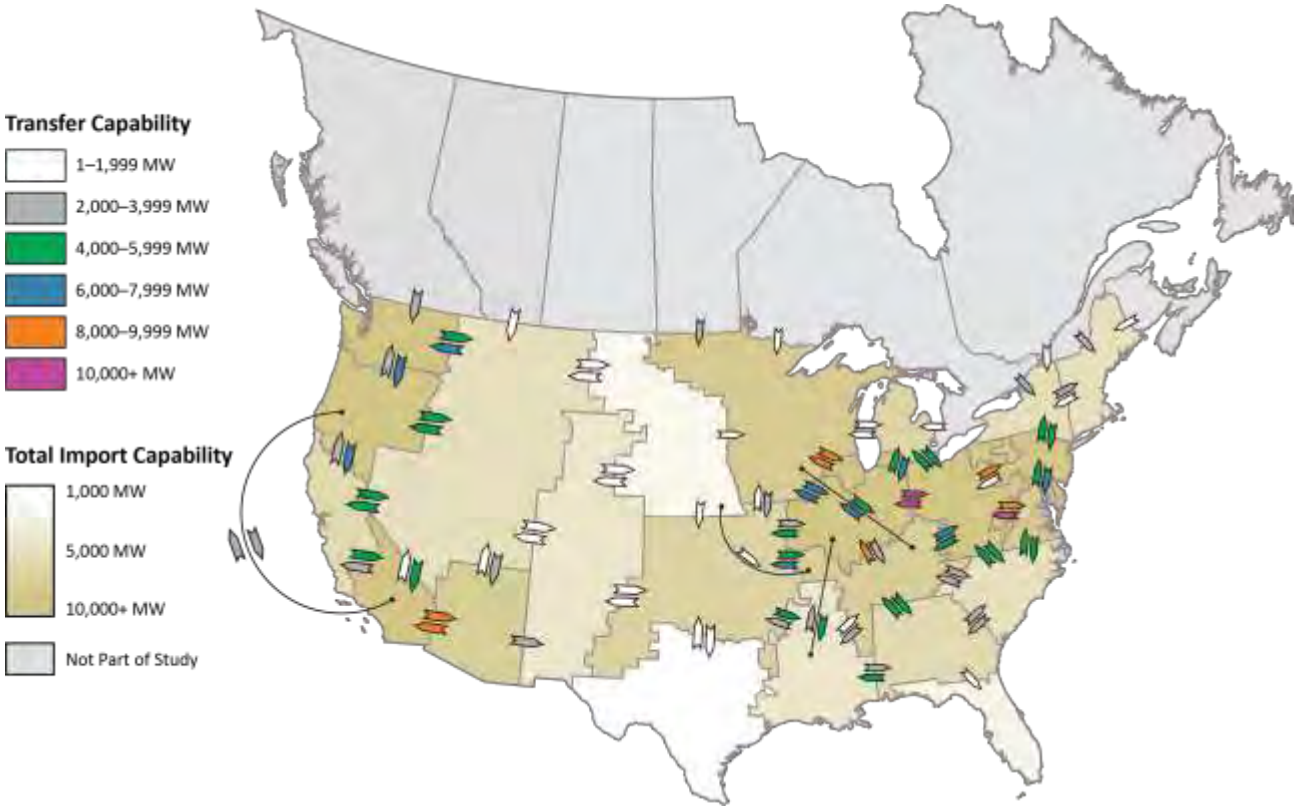

Figure ES.2: Transfer Capabilities (Winter)

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.

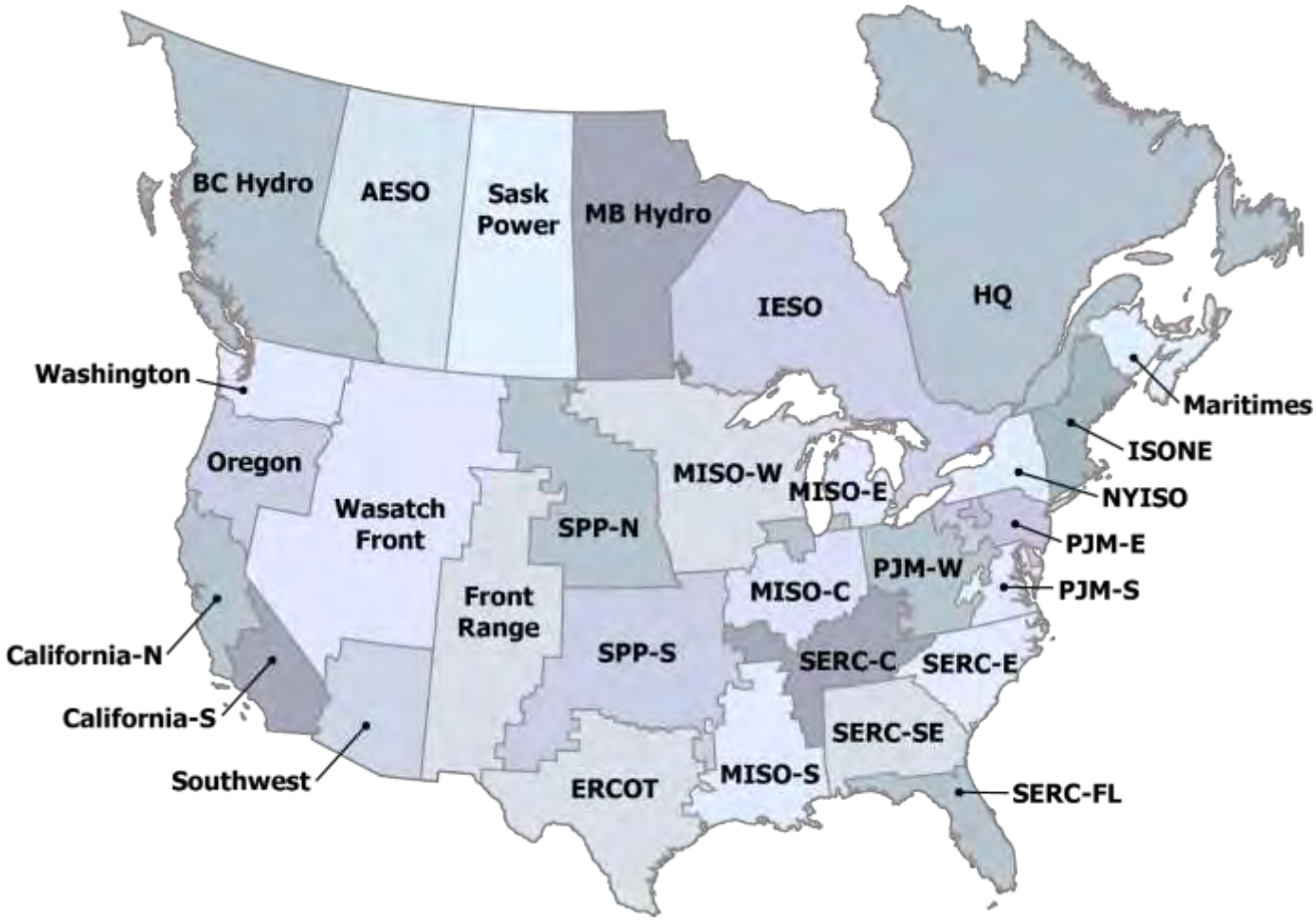

Figure 1.1: Transmission Planning Regions

[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)

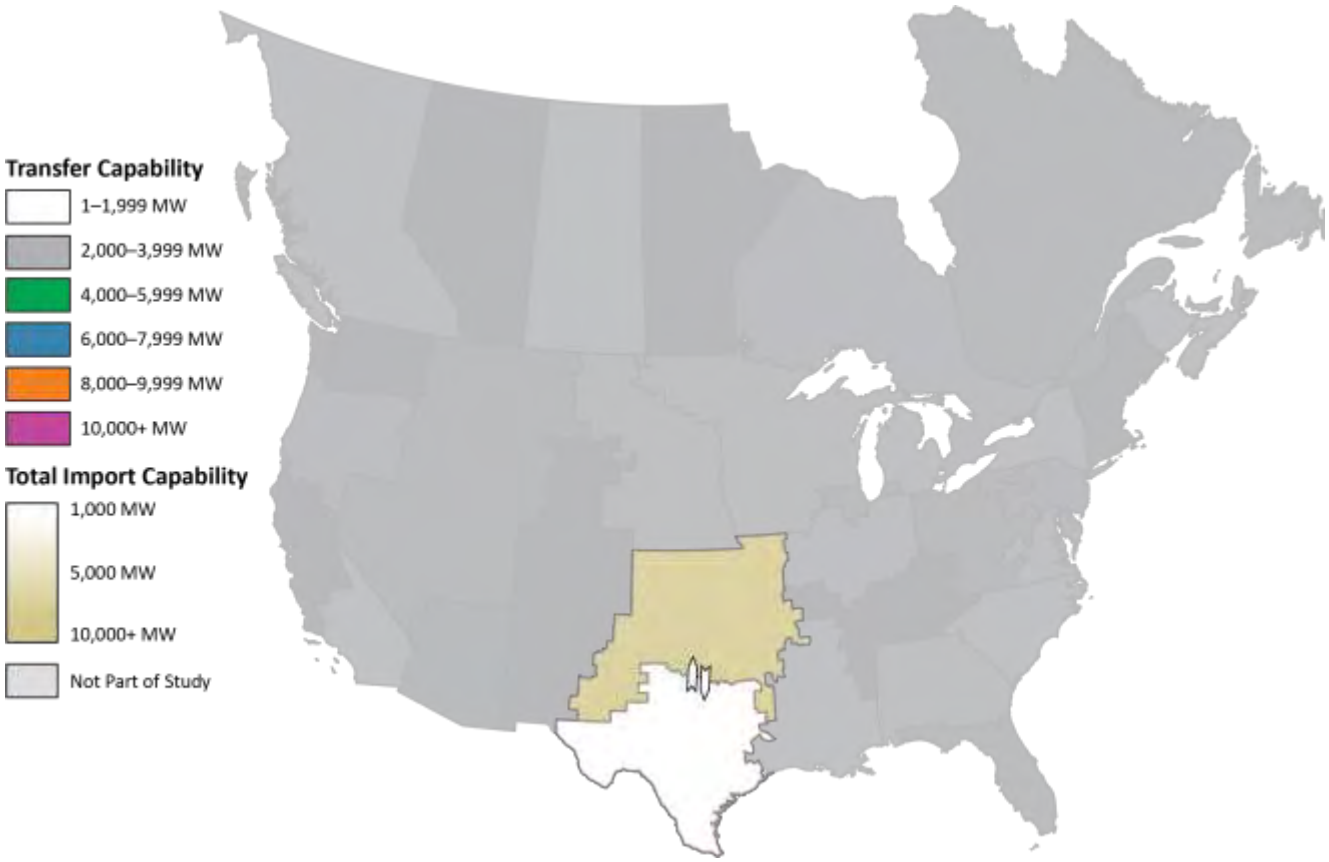

Figure 4.2: Transfer Capability Between ERCOT and Eastern Interconnections (Winter)

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.

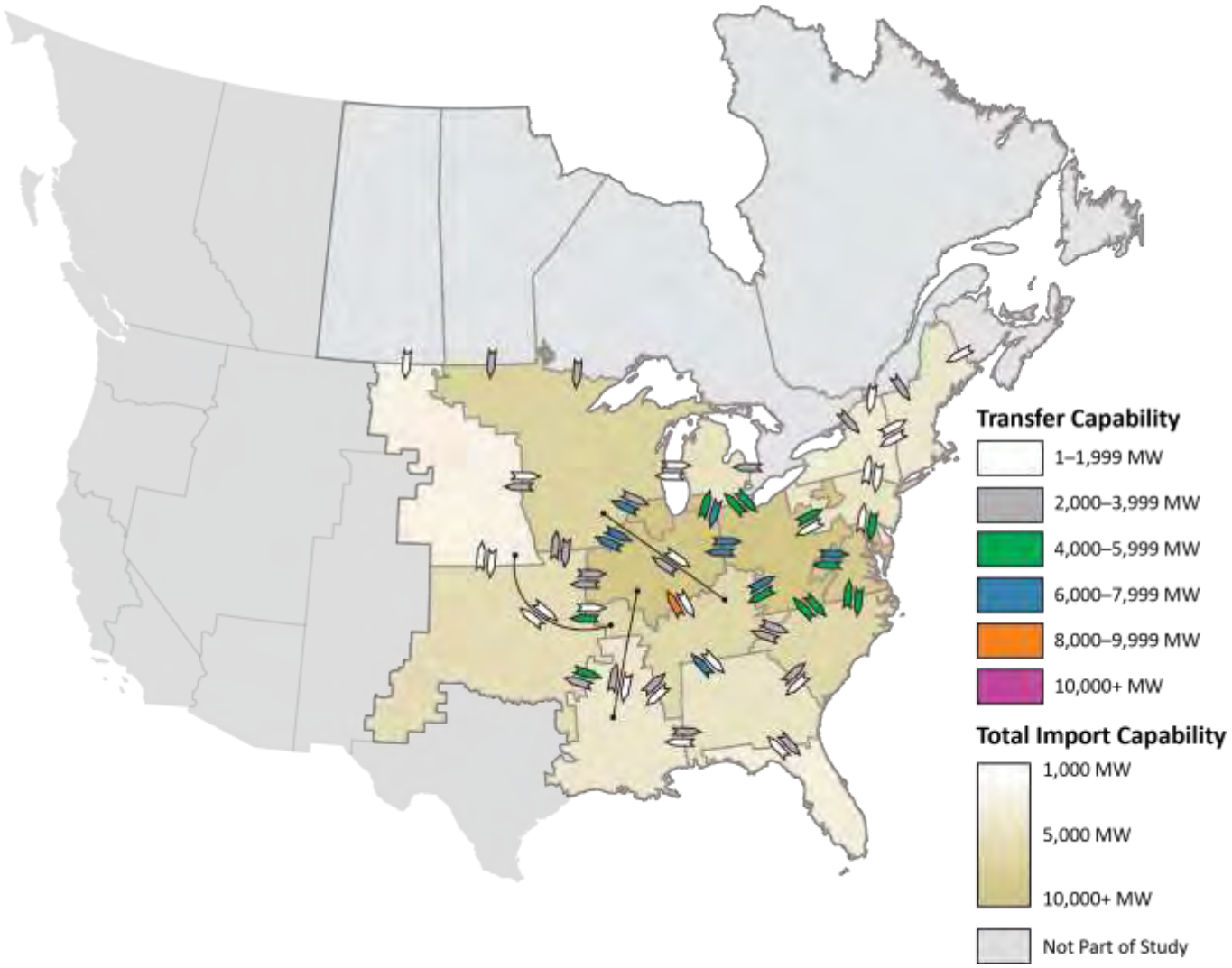

Figure 5.1: Transfer Capabilities of Eastern Interconnection Interfaces (Summer)

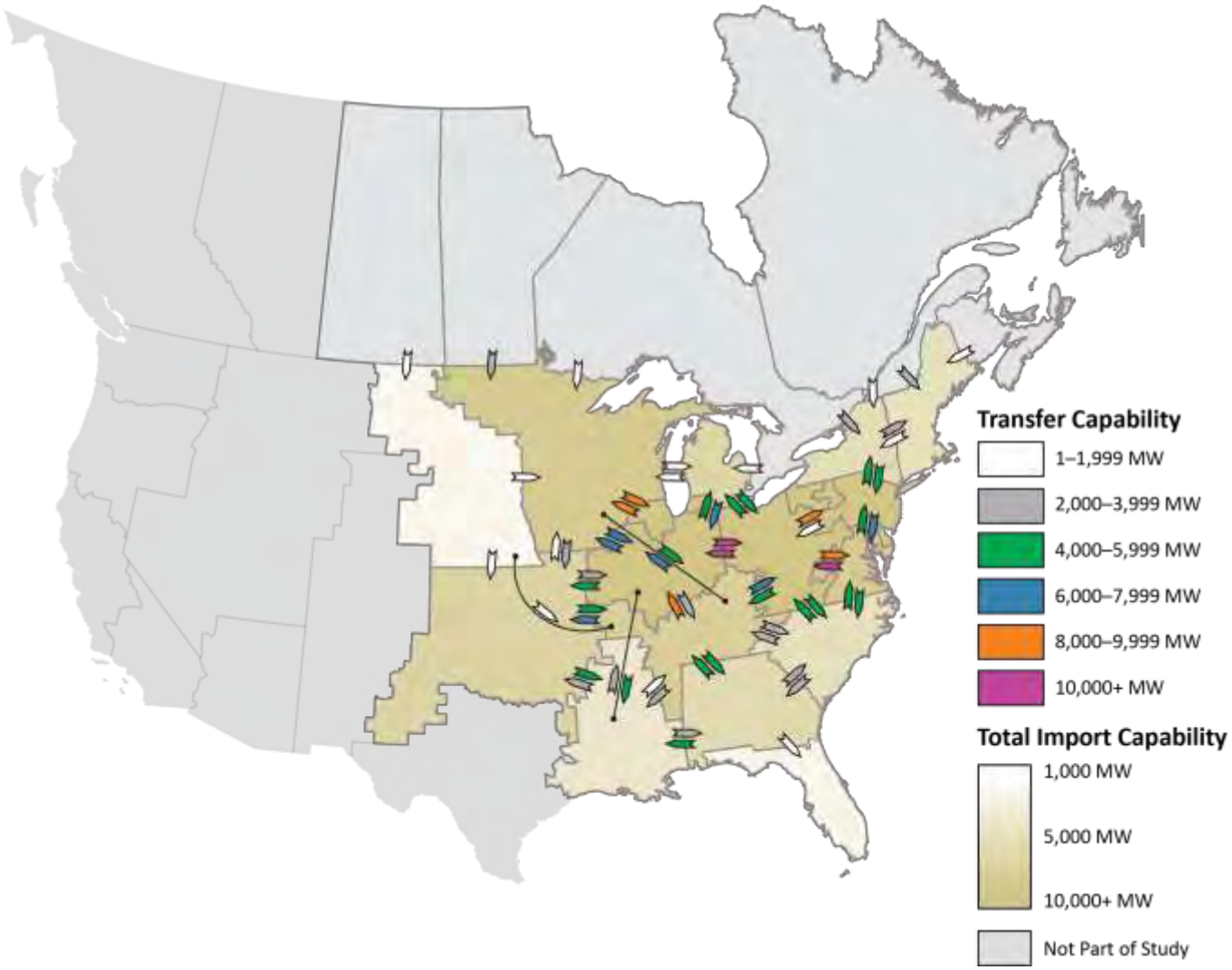

Figure 5.2: Transfer Capabilities of Eastern Interconnection Interfaces (Winter)

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

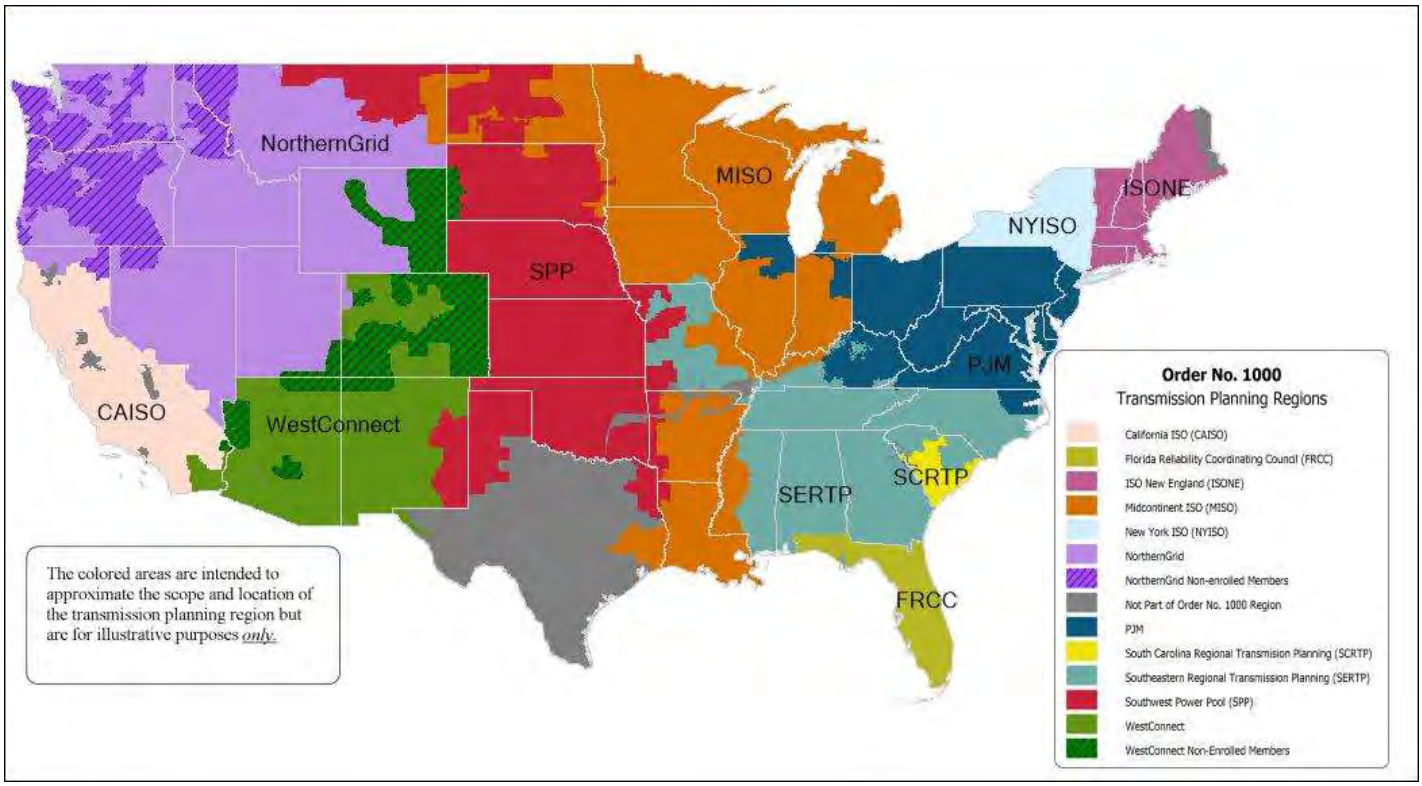

Figure 7.1: Areas Defined in FERC Order 1000

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 (MISO)	)))))

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

Exhibit 67

August 2025 Order

Order No. 202-25-7

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA), 16 U.S.C. § 824a(c), and section 301(b) of the Department of Energy Organization Act, 42 U.S.C. §7151(b), and for the reasons set forth below, I hereby determine that an emergency exists in portions of the Midwest region of the United States due to a shortage of electric energy, a shortage of facilities for the generation of electricity, and other causes. Issuance of this Order will meet the emergency and serve the public interest.

Order No. 202-25-3

J.H. Campbell Generating Plant (Campbell Plant) is a 1,420 MW coal-fired plant primarily owned by Consumers Energy Company (Consumers) and located in West Olive, MI. In 2021, Consumers announced that it planned to implement a "speed closure" of the Campbell Plant fifteen years before the end of its scheduled design life.[1] Instead of retiring the Campbell Plant at the end of its design life, Consumers planned to accelerate the Campbell Plant's retirement and discontinue its operations on May 31, 2025.

Order No. 202-25-3, issued pursuant to FPA section 202(c), required that the Campbell Plant remain in operation for 90 days, until August 21, 2025. That order was based on my determination that emergency conditions existed in the region served by the Midcontinent Independent System Operator, Inc. (MISO). Specifically, I determined that MISO likely faced tight reserve margins during the summer 2025 period, particularly during periods of high demand or low generation resource output. I determined that the continued operation of the Campbell Plant would provide additional generation capacity during these periods which would help prevent the potential loss of power to homes and local businesses in the areas that might have been affected by curtailments or outages that would otherwise pose a risk to public health and safety. I determined that the continued operation of the Campbell Plant was necessary to alleviate immediate and anticipated threats to reliability. My determination was based on a number of facts.

First, the North American Electric Reliability Corporation (NERC) released its 2025 Summer Reliability Assessment on May 14, 2025. In its assessment, NERC indicated that "[d]emand forecasts and resource data indicate that MISO is at elevated risk of operating reserve shortfalls during periods of high demand or low resource output."[2] In particular, NERC explained that the retirement of thermal generation capacity increased the likelihood of electricity supply

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[1] *See Consumers Energy Announces Plan to End Coal Use by 2025; Lead Michigan's Clean Energy Transformation*, Consumers Energy (June 23, 2021), https://www.consumersenergy.com/news-releases/news-release-details/2021/06/23/consumers-energy-announces-plan-to-end-coal-use-by-2025-lead-michigans-clean-energy-transformation. As a coal-fired facility, it would be difficult for the Campbell Plant to resume operations once it has been retired. Specifically, any stop and start of operation creates heating and cooling cycles that could cause an immediate failure that could take 30-60 days to repair if a unit comes offline.

[2] *2025 Summer Reliability Assessment*, North American Electric Reliability Corporation, at 16 (May 2025), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2025.pdf (NERC 2025 Summer Reliability Assessment).

shortfalls. NERC anticipated that the near-term period of greatest capacity shortfall for MISO would likely occur in August.[3]

Second, multiple generation facilities in Michigan have retired in recent years. According to the U.S. Energy Information Administration (EIA), "[s]ince 2020, about 2,700 megawatts of coal-fired generating capacity have been retired and no new coal-fired facilities are planned."[4] Additionally, EIA stated, "[t]ypically, Michigan's nuclear power plants have supplied about 30% of in-state electricity, but the amount of electricity generated by nuclear power plants in Michigan has declined as plants have been decommissioned."[5] The state's Big Rock Point nuclear power plant shut down in 1997, and the Palisades nuclear power plant closed in 2022. While the Palisades nuclear power plant may reopen in 2025, it was not projected to be available during the peak demand period this summer.[6]

Third, the Campbell Plant's retirement would have further decreased available dispatchable generation within MISO's service territory, adding to the loss of the other 1,575 MW of natural gas and coal-fired generation that has retired since the summer of 2024. Although MISO and Consumers have incorporated the planned retirement of the Campbell Plant into their supply forecasts and Consumers acquired a 1,200 MW natural gas power plant in Covert, MI, the NERC Assessment still anticipates "elevated risk of operating reserve shortfalls."[7]

Fourth, MISO's Planning Resource Auction Results for the 2025-2026 Planning Year, released in April 2025, noted that for the northern and central zones, which includes Michigan, "new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources."[8] While the results "demonstrated sufficient capacity," the summer months reflected the "highest risk and a tighter supply-demand balance" and these results "reinforce the need to increase capacity."[9]

Continuing Emergency Conditions

The emergency conditions that led to the issuance of Order No. 202-25-3 continue, both in the near and long term. The summer season has not yet ended, and the production of electricity from the Campbell Plant will continue to be a critical asset to maintain reliability in MISO this summer. That need is evidenced by the fact that the Campbell Plant was called on by MISO to generate large amounts of electricity during the heat wave that hit MISO this past June. According

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[3] *Id.*
[4] *Michigan State Profile and Energy Estimates*, U.S. Energy Info. Admin. (Oct. 17, 2024), https://www.eia.gov/state/print.php?sid=MI.
[5] *Id.*
[6] The start-up of Palisades is scheduled for the fourth quarter of 2025.
[7] NERC 2025 Summer Reliability Assessment at 16.
[8] *Planning Resource Auction—Results for Planning Year 2025–2026,* Midcontinent Independent System Operator, Inc., 13 (May 29, 2025), https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250529_Corrections694160.pdf. (MISO Planning Resource Auction – Results for Planning Year 2025-26).
[9] *Id*. at 2,12.

to the U.S. Environmental Protection Agency's data, over the month of June, the Campbell Plant generated approximately 664,000 MWh, running at 61% capacity.[10] In fact, between June 11 and August 18, MISO issued dozens of alerts to manage grid reliability in its Central Region in response to hot weather, severe weather, high customer load, forced generation outages, and transfer capability limits. MISO issued alerts for the Central Region on at least 40 of the 69 days between June 11 and August 18. In June, MISO issued alerts affecting the Central Region on 18 days, including an Energy Emergency Alert (EEA) level 1 ("Max Gen Step 1b") on June 23 to enable MISO to take emergency action to ensure grid stability, including bringing additional resources online.[11] The Central Region had alerts on 21 days in July, including one Max Generation Warning on July 29 and two Max Generation Alerts on July 28 and 29.[12] Two Capacity Advisory Initiate alerts have been issued in August to date.[13] Moreover, the May 2025 NERC Summer Reliability Assessment referenced a Seasonal Outlook issued by the National Oceanic and Atmospheric Administration (NOAA), which estimates that much of the Midwest has a 33%-40% chance to experience above-normal temperatures this summer.[14] The Seasonal Outlook released by NOAA on July 17, 2025, increased this estimate for much of the region to a 40%-50% chance.[15]

MISO's resource adequacy problems are not limited to the summer. In 2022, MISO requested Federal Energy Regulatory Commission (FERC) approval of its filing to revise its resource adequacy construct (including the Planning Resource Auction or PRA) to establish capacity requirements for each of the four seasons of the year rather than on an annual basis determined by peak summer demand.[16] MISO justified this revision by explaining that "Reliability risks associated with resource adequacy have shifted from 'Summer only' to a year-round

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[10] *See, Custom Data Download, EPA CAMPD (Clean Air Markets Program Data),* https://campd.epa.gov/data/custom-data-download *(search criteria to produce these results could include Emissions >> Monthly >> Unit (default) >>Apply >>"2025" and "June." The data can then be filtered to only include the Campbell Plant.)*

[11] An Energy Emergency Alert is an alert declared by the Transmission Provider in accordance with the NERC Operating Manual associated with the Transmission Provider's inability to provide for the Energy and Operating Reserve requirements of the MISO Balancing Authority Area. For more information, see MISO, FERC Electric Tariff, Module A, § 1.E (Definitions) (92.0.0). For more information on Energy Emergency Alert levels, see North American Electric Reliability Corporation. (n.d.). *EOP-011-1 Emergency Operations*. https://www.nerc.com/pa/stand/reliability%20standards/eop-011-1.pdf.

[12] A Max Gen Alert occurs when MISO is forecasting a potential capacity shortage. A Max Gen Warning is a warning to prepare for a possible Max Gen Event. *See* MISO Operating Procedures, https://efis.psc.mo.gov/Document/Display/9379 (20180920).

[13] A Capacity Advisory alert is an advisory issued based on the potential for limited operating capacity margins (<5%) in the following 2-3 days. *See* MISO Operating Procedures, https://efis.psc.mo.gov/Document/Display/9379 (20180920).

[14] NERC 2025 Summer Assessment at 9.

[15] *Seasonal Outlook*, NOAA Climate Prediction Ctr., (July 17, 2025), https://www.cpc.ncep.noaa.gov/products/predictions/long_range/seasonal.php?lead=1.

[16] M*idcontinent Independent System Operator, Inc.*, FERC Docket No. ER22-495-000 (Nov. 30, 2021). This request was approved by FERC on August 31, 2022. Midcontinent Independent System Operator, Inc., 180 FERC ¶ 61,141 (2022).

concern."[17] MISO noted that over 60 percent of all "MaxGen" events (events when MISO initiates emergency procedures because of concerns over the adequacy of available generation) occurred outside of the summer season.[18]

In December of 2023, MISO released an "Attributes Roadmap," in which it presented "an in-depth look at the challenges of operating a reliable bulk electric system in a rapidly transforming energy landscape."[19] Among other things, this report described changes in the time of year during which the risk of the loss of load was greatest. For the 2023/24 Planning Year, the greatest risk of loss of load was in the summer, but it is expected that by the summer of 2027, there will be an equal loss of load risk in both the summer and fall seasons. MISO also projects that the risk of loss of load in the winter and spring seasons, although not as high as in the summer or fall, will nevertheless increase over time.[20]

More recently, MISO affirmed the resource adequacy problems occurring outside of its summer season in its 2024 report entitled, "*MISO's Response to the Reliability Imperative.*"[21] In a section of that report entitled "Risks in Non-Summer Seasons," MISO again stressed that it has resource reliability concerns outside of the summer season.

> Widespread retirements of dispatchable resources, lower reserve margins, more frequent and severe weather events and increased reliance on weather-dependent renewables and emergency-only resources have altered the region's highest historic risk profile, creating risks in non-summer months that rarely posed challenges in the past.[22]

These MISO studies indicate that the emergency conditions caused by the loss of generation capacity in MISO extend past the summer season.

The evidence indicates that there is also a potential longer term resource adequacy emergency in MISO. When MISO reported the results of its PRA for the 2025-26 Planning Year, it noted that "new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources" in the northern and central zones, which include Michigan.[23]

On June 6, 2025, subsequent to the issuance of Order No. 202-25-3, the Organization of MISO States (OMS) and MISO issued the results of their survey, which has been conducted annually for many years to determine the degree to which expected capacity resources satisfy

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[17] MISO Transmittal Letter at 3, FERC Docket No. ER22-495-000 (Nov. 30, 2021).
[18] *Id.* at 3-4.
[19] *Attributes Roadmap*, MISO (Dec. 2023), https://cdn.misoenergy.org/2023%20Attributes%20Roadmap631174.pdf.
[20] *Id.* at 11.
[21] *MISO's Response to the Reliability Imperative*, MISO (Updated Feb. 2024), https://cdn.misoenergy.org/2024+Reliability+Imperative+report+Feb.+21+Final504018.pdf.
[22] *Id.* at 12.
[23] MISO Planning Resource Auction – Results for Planning Year 2025-26 at 13.

planning reserve margin requirements.[24] The 2025 Survey presented projections of resource adequacy for the summer of 2026 and subsequent years. Although the survey projected a potential capacity surplus for the summer of 2026, it also projected that at least 3.1 GW of additional generation capacity beyond currently committed generation capacity must be added to meet the projected planning reserve margin.[25] The survey also projected that there would be insufficient capacity to meet the peak demand for electricity in each of the following four summers, increasing from a deficit of 1.4 GW in 2027 to 8.2 GW in 2030.[26] Similar results were projected for MISO's winter seasons, with a small surplus of generation capacity in 2026, followed by increasing deficits the following four years.[27]

The primary reasons for these projected deficits also are shown on the OMS-MISO survey. Large amounts of existing generation capacity are projected to be retired each year while, at the same time, the demand for electricity is projected to increase at an accelerating pace.[28] Although the OMS-MISO survey projects generation capacity to continue to increase in the coming years with the addition of new potential generation assets, the increase in capacity is largely offset by the projected retirements, and does not keep up with the growth in demand.[29]

MISO has been taking steps to address these projected deficits. For example, on June 6, 2025, MISO submitted a proposal to FERC to establish an Expedited Resource Addition Study (ERAS) process to provide a framework for the expedited study of interconnection requests to address urgent resource adequacy and reliability needs in the near term. This proposal was approved by FERC on July 21, 2025.[30] The ERAS process should help expedite the construction of needed new capacity. However, resources studied under the ERAS will have commercial operation dates that are at least three years away, and are provided an additional three year grace period to commence commercial operations.[31] In addition, supply chain constraints impeding the acquisition of critical grid components, including large natural gas turbines and transformers, are likely to further hinder rapid construction and exacerbate reliability concerns.[32] Consequently, the new ERAS process is unlikely to result in the addition of any new generation capacity in the next few years.

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[24] *2025 OMS-MISO Survey Results*, OMS and MISO (Updated June 6, 2025) https://cdn.misoenergy.org/20250606%20OMS%20MISO%20Survey%20Results%20Workshop%20Presentation702311.pdf.
[25] *Id.* at 2.
[26] *Id.* at 7.
[27] *Id.* at 9.
[28] *Id.* at 7, 9.
[29] *Id.*
[30] M*idcontinent Independent System Operator, Inc.*, 192 FERC ¶ 61,064 (2025).
[31] 192 FERC ¶ 61,064 at P 84.
[32] *See generally, US Gas-Fired Turbine Wait Times as Much as Seven Years; Costs Up Sharply*, S&P Global (May 2025), US gas-fired turbine wait times as much as seven years; costs up sharply | S&P Global. "With demand for natural gas-fired turbines in the US rapidly accelerating amid power demand growth forecasts driven by AI, manufacturing, and electrification, wait times for turbines are anywhere between one and seven years depending on the model, and costs have increased considerably, experts told Platts."

Order 202-25-3 was preceded by executive orders on January 20, 2025, and April 8, 2025, in which President Donald J. Trump underscored the dire energy challenges facing the Nation due to growing resource adequacy concerns. Specifically, in Executive Order 14262, "Strengthening the Reliability and Security of the United States Electric Grid," President Trump emphasized that "the United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion of artificial intelligence data centers and increase in domestic manufacturing."[33] President Trump likewise recognized, in Executive Order 14156, "Declaring a National Energy Emergency," that the "United States' insufficient energy production, transportation, refining, and generation constitutes an unusual and extraordinary threat to our Nation's economy, national security, and foreign policy."[34] The Executive Order adds: "Hostile state and non-state foreign actors have targeted our domestic energy infrastructure, weaponized our reliance on foreign energy, and abused their ability to cause dramatic swings within international commodity markets."[35]

The Department's July 2025 Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid, issued pursuant to the President's directive in Executive Order 14262, details the myriad challenges affecting the Nation's energy outlook. "Absent decisive intervention, the Nation's power grid will be unable to meet projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation."[36] The prolific growth of data centers for the development of AI, as well as their immense energy needs, presents a new and unexpected source of load growth. This growth is illustrated by the fact that there are more than twenty AI companies operating in Michigan alone.[37] In addition, as just one example, Consumers has announced an additional 1 GW of new power to a planned hyperscale data center and "continue[s] to see positive momentum with data centers within the 9 GW pipeline . . . ."[38]

Grid operators—including MISO itself—have likewise acknowledged the Nation's current energy crisis. For instance, during a March 25, 2025, hearing before the House Committee on Energy and Commerce, Jennifer Curran, Senior Vice President, Planning and Operations, MISO, testified that "the MISO region faces resource adequacy and reliability challenges due to the

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[33] Executive Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025) (*Strengthening the Reliability and Security of the United States Electric Grid*), https://www.whitehouse.gov/presidential-actions/2025/04/strengthening-the-reliability-and-security-of-the-united-states-electric-grid/.

[34] Executive Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025) (*Declaring a National Energy Emergency*), https://www.whitehouse.gov/presidential-actions/2025/01/declaring-a-national-energy-emergency/.

[35] *Id*.

[36] *See also Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid*, U.S. Department of Energy (July 2025), at 1, https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf.

[37] Ekku Jokinen, *Top 21 Artificial Intelligence Companies in Michigan*, (last accessed Aug. 13, 2025), https://www.inven.ai/company-lists/top-21-artificial-intelligence-companies-in-michigan.

[38] *See Michigan utility Consumers Energy to provide 1GW of power to new hyperscale data center*, Data Center Dynamics (August 05, 2025), https://www.datacenterdynamics.com/en/news/michigan-utility-consumers-energy-to-provide-1gw-of-power-to-new-hyperscale-data-center/ (quoting Consumers Energy CEO Garrick Rochow).

changing characteristics of the electric generating fleet, inadequate transmission system infrastructure, growing pressures from extreme weather, and rapid load growth."[39] Ms. Curran also described "much stronger growth [in demand for electricity] from continued electrification efforts, a resurgence in manufacturing, and an unexpected demand for energy-hungry data centers to support artificial intelligence."[40] She added, "[a] growing reliability risk is that the rapid retirement of existing coal and gas power plants threatens to outpace the ability of new resources with the necessary operational characteristics to replace them."[41]

ORDER

FPA section 202(c)(1) provides that whenever the Secretary of the Department of Energy determines "that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy," then the Secretary has the authority "to require by order . . . such generation, delivery, interchange, or transmission of electric energy as in its judgment will best meet the emergency and serve the public interest."[42] This statutory language constitutes a specific grant of authority to the Secretary to require the continued operation of the Campbell Plant when the Secretary has determined that such continued operation will best meet an emergency caused by a sudden increase in the demand for electric energy or a shortage of generation capacity.

Such is the case here. As described above, the emergency conditions resulting from increasing demand and accelerated retirements of generation facilities supporting the issuance of Order No. 202-25-3 will continue in the near term and are also likely to continue in subsequent years. This could lead to the potential loss of power to homes and local businesses in the areas that may be affected by curtailments or outages, presenting a risk to public health and safety. Given the responsibility of MISO to identify and dispatch generation necessary to meet load requirements, I have determined that, under the conditions specified below, continued additional dispatch of the Campbell Plant is necessary to best meet the emergency and serve the public interest under FPA section 202(c).

To ensure the Campbell Plant will be available if needed to address emergency conditions, the Campbell Plant shall remain in operation until November 19, 2025.[43]

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[39] Keeping the Lights On: Examining the State of Regional Grid Reliability Before the House Committee on Energy and Commerce, Subcommittee on Energy, 119th Cong. (Mar. 25, 2025) (statement of Ms. Jennifer Curran, Senior Vice President for Planning and Operations, Midcontinent Independent System Operator), at 5, https://democrats-energycommerce.house.gov/sites/evo-subsites/democrats-energycommerce.house.gov/files/evo-media-document/witness-testimony_curran_eng_grid-operators_03.25.2025.pdf.

[40] *Id.* at 6.

[41] *Id.* at 7.

[42] Although the text of FPA section 202(c) grants this authority to "the Commission," section 301(b) of the Department of Energy Organization Act transferred this authority to the Secretary of the Department of Energy. *See* 42 U.S.C. § 7151(b) (2018).

[43] 16 U.S.C. § 824a(c)(4).

Based on my determination of an emergency set forth above, I hereby order:

A. From August 21, 2025, MISO and Consumer Energy shall take all measures necessary to ensure that the Campbell Plant is available to operate. For the duration of this Order, MISO is directed to take every step to employ economic dispatch of the Campbell Plant to minimize cost to ratepayers. Following the conclusion of this Order, sufficient time for orderly ramp down is permitted, consistent with industry practices. Consumers Energy is directed to comply with all orders from MISO related to the availability and dispatch of the Campbell Plant.

B. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters as determined by MISO pursuant to paragraph A. MISO shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether the Campbell Plant has operated in compliance with the allowances contained in this Order.

C. All operation of the Campbell Plant must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions. This Order does not provide relief from any obligation to pay fees or purchase offsets or allowances for emissions that occur during the emergency condition or to use other geographic or temporal flexibilities available to generators.

D. By September 4, 2025, MISO is directed to provide the Department of Energy (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability of the Campbell Plant consistent with this Order. MISO shall also provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time.

E. Consumers is directed to file with the Federal Energy Regulatory Commission Tariff revisions or waivers to effectuate this Order. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).

F. This Order shall not preclude the need for the Campbell Plant to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.

G. Because this Order is predicated on the shortage of facilities for generation of electric energy and other causes, the Campbell Plant shall not be considered a capacity resource.

H. This Order shall be effective from 00:00 Eastern Daylight Time (EDT) on August 21, 2025, and shall expire at 00:00 EDT on November 19, 2025, with the exception of applicable compliance obligations in paragraph D.

I. Issued in Norfolk, Virginia at 8:50pm Eastern Daylight Time on this 20th day of August 2025.

Chris Wright
Secretary of Energy

cc: **FERC Commissioners**
Chairman David Rosner
Commissioner Lindsay S. See
Commissioner Judy W. Chang

Michigan Public Service Commissioners
Chairman Dan Scripps
Commissioner Katherine Peretick
Commissioner Shaquila Myers

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)
Emergency Order: Midcontinent	)
Independent System Operator	)
(MISO)	)
	)

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.

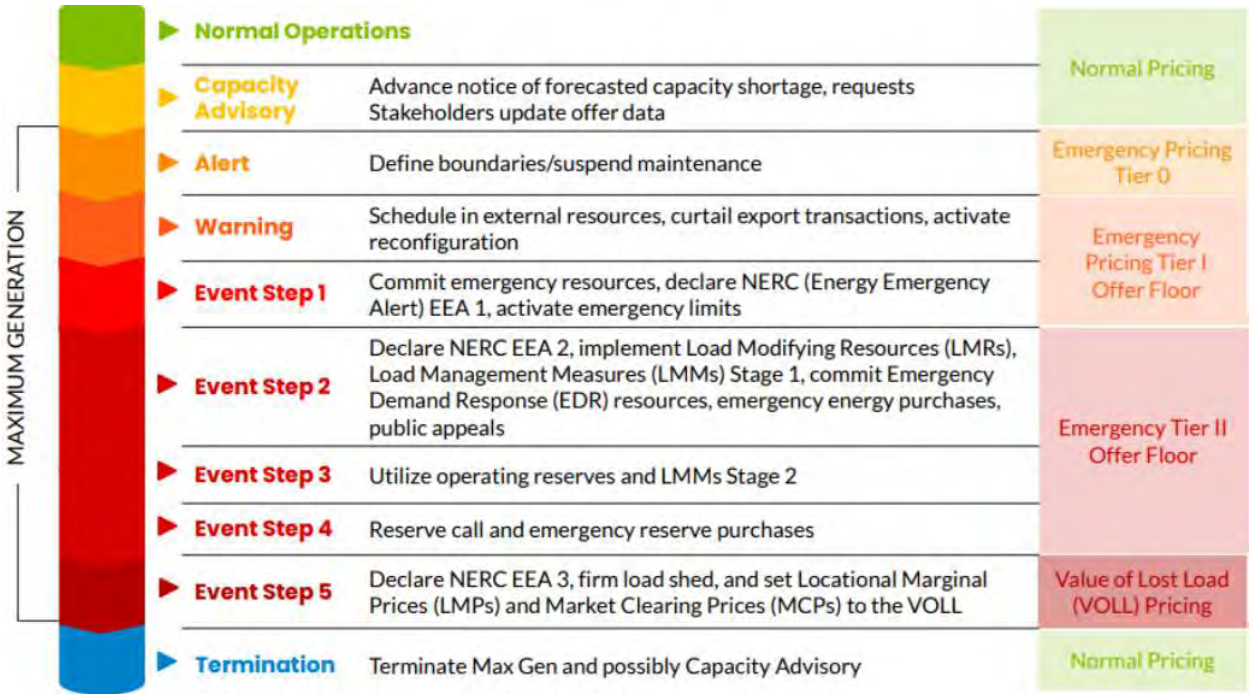

Figure 1: MISO chart showing its steps for Maximum Generation Events

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.

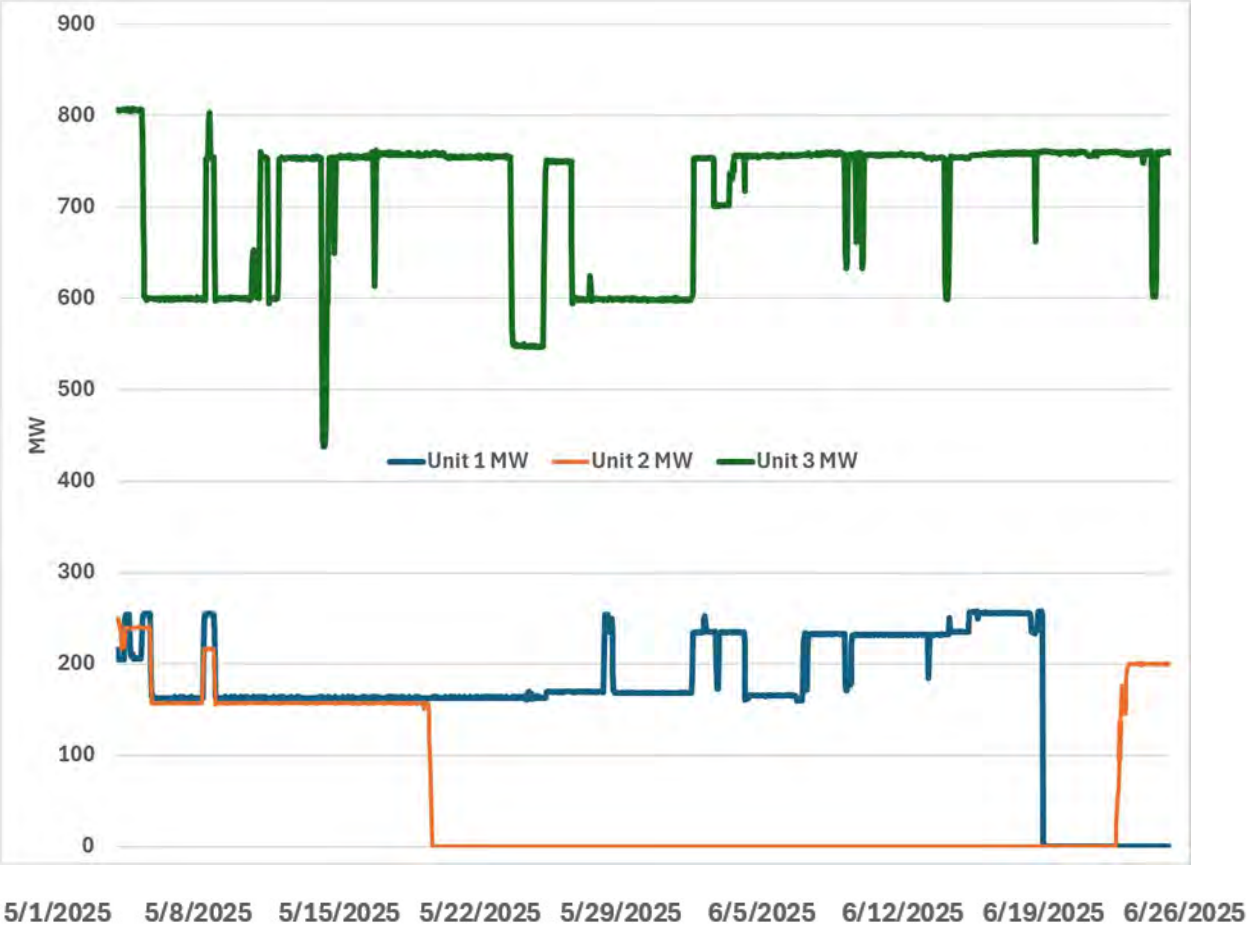

Figure 2: Campbell unit output over May and June 2025, from EPA CEMS dataset

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

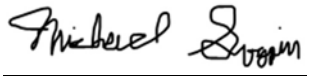
-FERC, *Consumers Energy Company submits FERC Form 1 report for 2024/Q4* (Mar. 2025), *available at* https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20250320-8006

-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	)
(MISO)	)
	)

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

Exhibit 69

Powers Sept. Decl.

DECLARATION OF BILL POWERS, P.E.

I, Bill Powers, P.E., declare as follows:

1. I am the principal of Powers Engineering, an engineering firm that consults on issues related to the operation of, and control of pollution from, power plants, including coal-fired power plants. My office is located in San Diego, California.

2. My professional and educational experience is set forth in the curriculum vitae attached to this declaration (Attachment A) and in the declaration I prepared on the U.S. Department of Energy's and Secretary of Energy Christopher Wright's ("DOE") May 23, 2025 order regarding Consumers Energy Company's ("Consumers") J.H. Campbell coal-fired power plant (Order No. 202-25-3) ("May Order"). That declaration, attached here as Attachment B, was filed with DOE on June 18, 2025 as an attachment to the Request for Rehearing of the May Order filed by Sierra Club, Natural Resources Defense Council, Michigan Environmental Council, Environmental Defense Fund, Environmental Law and Policy Center, Vote Solar, Public Citizen, Union of Concerned Scientists, Ecology Center, and Urban Core Collective ("Public Interest Organizations").

3. My June 18 declaration provides my opinion on: (A) the extent to which Campbell can operate reliably after May 31, 2025; (B) whether Campbell can operate effectively as a peaking unit; and (C) easily attainable steps DOE can require to ensure Campbell's operations are consistent with environmental requirements and minimize adverse environmental impacts. I did not opine on the claimed energy emergency described in the Order, nor did I opine on alternatives to Campbell that are available to DOE to effectively address the circumstances described in the Order.

4. I am familiar with DOE's August 20, 2025 order regarding Consumers' Campbell plant (Order No. 202-25-7) ("August Order"). I have been asked by the Public Interest Organizations to opine on: (A) the continued validity of the opinion I provided in my June 18 declaration; (B) the extent to which Campbell can reliably operate in light of any new information that has emerged since my June 18 declaration; and (C) environmental implications of Campbell's continued operation, including adverse environmental impacts and consistency with environmental requirements.

A. <u>The continued validity of the opinion I provided in my June 18 declaration.</u>

5. The opinion I provided in my June 18 declaration continues to be valid. I am not aware of any new information that weakens or undermines my June 18 declaration. In fact, as I discuss below, I am aware of new information that reinforces my opinion. Thus, I fully reaffirm and incorporate here my June 18 declaration.

6. Additionally, I do not identify anything in the August Order that responds to my June 18 declaration. I also do not identify in the August Order material that addresses the types of matters addressed in my June 18 declaration.

B. <u>The extent to which Campbell can reliably operate in light of any new information that has emerged since my June 18 declaration.</u>

7. In my professional opinion, it is unlikely that Campbell can be depended upon to operate reliably in its current state as of August 2025. This is especially true if the plant is required to run for extended periods of time; is required to stop and start numerous times; or attempts to start up at an accelerated rate in response to extreme demand conditions. The reasons for that opinion are set forth in my June 18 declaration at pages 4–17 (which, again, I incorporate here).

8. As I explained in my June 18 declaration, each of Campbell's three units suffered outages in 2023 and 2024 that tended to be long, recurrent, and due to the types of failures that are the predictable result of old equipment, minimal capital spending, and minimal major maintenance spending.[1] The record evidence shows that, in the 2022-2025 period, Consumers significantly cut back on capital expenditures and major maintenance on Campbell Units 1, 2, and 3:

- **Capital spending:** Consumers reduced its capital spending by approximately **91 percent** across all three units compared to the amount the company projected to spend if Units 1-2 operated until 2031 and Unit 3 operated until 2039.[2]
- **Major maintenance spending:** Consumers reduced its major maintenance spending by approximately **62-78 percent** across all three units compared to the amount the company projected to spend if Units 1-2 operated until 2031 and Unit 3 operated until 2039.[3]

The reductions in Consumers' capital and major maintenance spending on Units 1-3 that followed the Integrated Resource Plan (IRP) that established a May 2025 retirement date are summarized in the following table:

Capital spending	Pre-IRP projected spend 2022-25 ($MM)	Post-IRP actual/projected spend 2022-25 ($MM)	% reduction
Units 1&2	60.6	4.1	93
Unit 3	85.5	8.4	90
Major maintenance spending			
Units 1&2	14.4	5.5	62
Unit 3	23.5	5.1	78

[1] Attachment B (June 18 declaration), pp. 4-5.
[2] Ibid, pp. 5-6.
[3] Ibid.

9. Further, Consumers recently confirmed that it did "not record[] any capital expenditures at the Campbell plant in the two-year period prior to May 31, 2025."[4] Consumers' lack of capital expenditures in that two-year period is consistent with the opinion in my June 18 declaration that Consumers has been transitioning from a preventive capital spending and maintenance structure to a reactive, "fix it if it breaks" approach.[5]

10. Campbell will continue to degrade in 2025 to the extent there is a continued lack of capital spending and minimal major maintenance spending. *Id.* at 5.

11. I am not aware of any calculations or itemizations of costs that Consumers has incurred since the May Order.[6]

12. It is my opinion that if Campbell's ability to operate reliably has improved since my June 18 declaration, it is likely the result of Consumers making capital expenditures or performing major maintenance that it had cancelled after Campbell's May 31, 2025 retirement date was established in the 2021 Integrated Resource Plan settlement. I identified those foregone capital expenditures and major maintenance projects in my June 18 declaration.[7] The table below identifies a subset of those cancelled capital and major maintenance projects that are the minimum that would likely be necessary to improve Campbell's ability to operate reliably.[8]

[4] RFR Exhibit 101, Consumers, Informal Response to Michigan AG Campbell Questions, June 10, 2025, Question 1 ("Consumers June Responses to AG").
[5] Attachment B (June 18 declaration), pp. 15-16.
[6] RFR Exhibit 101 (Consumers June Responses to AG), Question 2 (stating that Consumers "has not performed any calculations to determine any amounts it could or would include in a request for cost recovery" to comply with the May Order).
[7] Attachment B (June 18 declaration), pp. 8-14.
[8] Ibid.

Unit 1	Unit 2	Unit 3
Replacement of: • Pulse Jet Fabric Filter (PJFF) bags • Boiler components • Superheat outlet pendant • Air preheater baskets	**Replacement of:** • Horizontal reheat • Selective Catalytic Reduction (SCR) catalyst • Burner assemblies • Turbine reheat stop valve • Boiler components	**Two major maintenance projects:** • Boiler feedwater pump inspection • Turbine overhaul **Replacement of:** • PJFF bags • High pressure feedwater heater 8A • SCR catalyst

13. New information reinforces my opinion that it is unlikely Campbell can be depended upon to operate reliably. For example, during June 2025—the first full calendar month of operation under the May Order—Unit 1 experienced an outage on June 23 and remained offline the rest of the month.[9]

14. In addition, Unit 2 was largely offline in June 2025, producing power on only four days in a 30-day month. It produced significant amounts of power on only three days, June 28-30, and then operating only at approximately 50 percent of its rated capacity when online.[10] Multiple operational issues contributed to Unit 2's poor performance. On July 17, 2025, Consumers informed Michigan's environmental agency that:

> [Campbell] Unit 2 was offline on May 19, 2025 and there was no immediate plan as of May 27, 2025 to bring it back online. But after further evaluation and interpretation of the DOE order . . . it has been determined that it is necessary to attempt to repair and operate Unit 2 . . . .[11]

[9] RFR Exhibit 102, EPA, Clean Air Markets Program Data (CAMPD), June daily 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 "daily 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." ("CAMPD daily emissions data").
[10] Ibid.
[11] RFR Exhibit 103, Joseph Firlit, Consumers, email to April Lazzaro, EGLE, July 17, 2025 ("July 17 email from Consumers to EGLE").

Unit 2 was "out of service due to needed boiler tube repairs and other balance of plant work"[12] when the 90-day period covered by the May Order began on May 23.[13] At the time, the estimated return to service was June 27, 2025.[14] Unit 2 then operated briefly between June 25 and July 4, 2025 before going back offline to address a water intake issue.[15]

15. Unit 2's poor performance in June 2025 is consistent with its recent operational performance. Unit 2 had very high forced outage rates in 2023 and 2024, 57.32 percent and 48.07 percent respectively, caused by worn, obsolete, and difficult to repair components.[16]

16. In my opinion, Unit 2 is suffering from chronic component operational deficiencies that severely impair its reliability.

17. Even if it were available to operate, Unit 2 takes approximately 36 hours to start up from a cold condition. Unit 2 could not be relied upon to provide any power, much less peaking power to meet high demand summer load conditions, during the June – August 2025 period covered by the May Order. The approximate number of hours required for startup from a cold condition for each Campbell unit are shown in the table below.[17] These startup times are very long, even for coal units. In contrast, peaking gas turbines can start up in 10 minutes or less.[18]

Unit 1	Unit 2	Unit 3
24 hours	36 hours	72 hours

[12] Petrotech, *Balance of Plant in Power Generation*, webpage accessed on August 31, 2025: https://petrotechinc.com/balance-of-plant-in-power-generation/. "Coal and thermal plants require extensive BoP (balance of plant) systems to handle ash removal, feedwater management, as well as pollution control."
[13] RFR Exhibit 101 (Consumers June Responses to AG), Question 4.
[14] Ibid.
[15] RFR Exhibit 103 (July 17 email from Consumers to EGLE).
[16] Attachment B (June 18 declaration), pp. 4-5.
[17] RFR Exhibit 101 (Consumers June Responses to AG), Question 5.
[18] Attachment B (June 18 declaration), p. 17.

18. The problems with Campbell Units 1 and 2 reaffirm my opinion that it is unlikely Campbell can be depended upon to operate reliably, including because Consumers transitioned from a preventative to a reactive approach to plant maintenance in recent years. As I explain in my June 18 declaration, it is reasonable to assume that much of the $161 million in planned capital and major maintenance projects that Consumers cancelled at Campbell in recent years was necessary to ensure continued, nominally reliable plant operations. Campbell can no longer operate reliably due to the lack of capital and major maintenance investment in recent years. This reality contradicts a basic premise of the August Order, which claims there is an ongoing need for Campbell—to assure grid reliability—at least through 2030.[19]

19. Campbell is a 1,560 MW power plant.[20] Campbell operated well below its capacity in June 2025, with output between approximately 800 MW and 1,000 MW.[21] Campbell was in partial outage throughout the month, with one or two of the three units, either Unit 1 or Unit 2 or both, offline at any given time.[22] The statement in DOE's Order that the Campbell units must operate continuously to reliably produce power is in error.[23] Units 1 and 2 demonstrated they cannot stay online continuously in June 2025 and that they must stop and start, with long outages between stops, due to their unreliable condition.

20. The Campbell outages that occurred in June 2025 were predictable due to the lack of the necessary capital and major maintenance expenditures in recent years. Neither Unit 1 nor

[19] August Order, p. 5. "The (MISO) survey also projected that there would be insufficient capacity to meet the peak demand for electricity in each of the following four summers, increasing from a deficit of 1.4 GW in 2027 to 8.2 GW in 2030."
[20] May Order, p. 1.
[21] RFR Exhibit 102 (CAMPD daily emissions data) (numbers derived by dividing the "Gross Load MWh" values by 24 (hours)).
[22] Ibid.
[23] August Order, p. 1, footnote 1: "As a coal-fired facility, it would be difficult for the Campbell Plant to resume operations once it has been retired. Specifically, any stop and start of operation creates heating and cooling cycles that could cause an immediate failure that could take 30-60 days to repair if a unit comes offline."

Unit 2 could reliably provide power throughout the first full calendar month of the May Order. The unreliability of the Campbell units will likely increase if these units continue to operate.

C. The extent to which Campbell's operations are consistent with environmental requirements and minimize adverse environmental impacts in light of any new information that has emerged since my June 18 declaration.

21. Burning coal produces pollutants. These pollutants include nitrogen oxide ("NO_x"), sulfur dioxide ("SO_2"), and particulate matter, among others.

22. Large quantities of these pollutants will enter the atmosphere if uncontrolled.

23. Coal-burning power plants must include air emission control equipment to reduce the pollutants in the coal boiler exhaust gas stream. The equipment still allows some level of pollution to enter the atmosphere, but it reduces the amount of pollutants entering the atmosphere.

24. Some of that air cleaning equipment includes pulse jet fabric filters and SCR catalysts. Pulse jet fabric filters remove particulate matter from the boiler exhaust gas. Pulse jet fabric filter bags are degraded over time by fly ash erosion and plugging, resulting in particulate "bleed through" and potentially bag rupture, which would result in increased particulate matter emissions.[24] The SCR catalysts are used to reduce NO_x emissions. Over time the catalyst is poisoned by trace metals and fouled by fly ash.[25] NO_x emissions increase as the catalyst degrades.

[24] Power Engineering, *Real World Performance Results of Fabric Filters on Utility Coal-Fired Boilers*, August 1, 2012: https://www.power-eng.com/environmental-emissions/real-world-performance-results/.
[25] Power Engineering, *Selective Catalytic Reduction: Operational Issues and Guidelines*, November 1, 2011: https://www.power-eng.com/environmental-emissions/selective-catalytic-reduction-operational-issues-and-guidelines/.

25. In order for air cleaning equipment like pulse jet fabric filters and SCR catalysts to do the job they are supposed to do, they must be kept in good working order. They also must be replaced when at their end of life.

26. The Campbell units depend on pulse jet fabric filters and SCR catalysts to reduce the units' air pollution emissions.

27. In my June 18 declaration, I explained the hazards if Campbell's pulse jet fabric filters and SCR catalysts are not in good working order.[26] These hazards include releases of particulate matter and NO_x. I further explained that DOE should require any Campbell unit that exceeds air permit limits for opacity, NO_x, or SO_2 during operation of Units 1 -2—as registered on the continuous monitors installed on each unit—to shut down. My opinion remains the same following review of new information available since the June 18 declaration.

28. Campbell's SCR catalysts are past their end of life. According to Consumers, "Campbell Unit 2 and Campbell Unit 3 selective catalytic reduction catalysts [were] at end of life" as of June 10.[27] The company further recognized on June 10 that new catalyst is needed should DOE continue preventing Campbell's retirement.[28] Consumers' estimate for one layer of catalyst at Campbell Unit 2 is $3 million and at Campbell Unit 3 is $5 million.[29] The company also noted that catalyst purchases "typically require six-to-twelve-month lead time."[30]

29. In addition, according to Consumers, "Campbell Unit 3 is overdue for [pulse jet fabric filter] bag changeout."[31] Consumers cancelled a prior changeout "due to expected site

[26] Attachment B (June 18 declaration), pp. 19-20.
[27] RFR Exhibit 101 (Consumers June Responses to AG), Question 2.
[28] Ibid (stating that the SCR catalysts for Campbell Units 2 and 3 "are expected to perform adequately for the next 90 days, however additional extensions beyond this will eventually require catalyst addition").
[29] Ibid.
[30] Ibid.
[31] Ibid, Question 15.

closure."[32] Consumers acknowledged on June 10 that continued operation of Campbell beyond August 2025 "may negatively impact [] performance" of the Unit 3 pulse jet fabric filter.[33] Consumers' rough estimate for Campbell Unit 3 pulse jet fabric filter full bag changeout (24 compartments with 28,272 bags total) is $7 million to $10 million.[34]

30. The Consumers air permit requires that "[a]ny air cleaning device shall be installed, maintained, and operated in a satisfactory manner and in accordance with the Michigan Air Pollution Control rules and existing law."[35]

31. In my professional opinion, and based on the available information, Campbell's SCR catalysts and pulse jet fabric filter bags are air cleaning devices that are not installed, maintained, and operated in a satisfactory manner at this time. A SCR catalyst at its end of life cannot do its job to remove NO_x in a satisfactory manner. Nor can a pulse jet fabric filter overdue for bag replacement do its job to effectively remove particulate from the boiler exhaust gas.

32. In my professional opinion, including because of the state of the SCR catalysts and pulse jet fabric filters, it appears that operating Campbell violates the air permit, or at minimum may be in serious conflict with the permit.

33. I also opined in my June 18 declaration that there are alternatives to running Campbell to meet an extreme peak demand that would produce far less environmental harm. The new emissions and discharge information since filing my June 18 declaration reinforces my opinion.

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[32] Ibid.
[33] Ibid.
[34] Ibid.
[35] Attachment C, Consumers Energy, J.H. Campbell Generating Complex, Renewable Operating Permit, Permit Number: MI-ROP-B2835-2020b, p. 6.

34. U.S. EPA's Clean Air Markets Program Data ("CAMPD") show that, between June 1 and June 30, 2025, Campbell emitted approximately 694,696 pounds of SO_2 and 483,868 pounds of NO_x. Campbell also emitted 1,453,247,200 pounds of carbon dioxide in the same time period.[36] NO_x is a lung irritant and a precursor to ozone formation.[37] SO_2 can harm the respiratory system and contribute to the formation of acid rain.[38]

35. Campbell is located in Ottawa County, Michigan. The counties adjacent to Ottawa County—Muskegon County to the north and Allegan County to the south—have been identified by the EPA as ozone non-attainment areas.[39] Campbell Units 1-3, when operational, emit ozone precursors that form ozone in the atmosphere, which is carried to surrounding areas and could contribute to ozone non-attainment in Muskegon and Allegan counties.

36. Discharge Monitoring Reports that Consumers filed with Michigan's environmental agency show that, between June 1 and July 31, 2025, Campbell withdrew and discharged approximately 40 billion gallons of cooling water to Lake Michigan.[40] The primary environmental impacts of this cooling water usage is (1) degradation of marine fauna being run through cooling water circulation pumps and (2) the deleterious impacts on marine fauna of the 20°F or more increase in water temperature at the point of cooling water discharge.

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[36] RFR Exhibit 102 (CAMPD daily emissions data).
[37] U.S. EPA, *Basic Information about NO_2*, webpage accessed August 31, 2025: https://www.epa.gov/no2-pollution/basic-information-about-no2.
[38] U.S. EPA, *Sulfur Dioxide Basics*, webpage accessed August 31, 2025: https://www.epa.gov/so2-pollution/sulfur-dioxide-basics.
[39] U.S. EPA., Michigan Nonattainment/Maintenance Status for Each County by Year for All Criteria Pollutants, webpage accessed September 3, 2025: https://www3.epa.gov/airquality/greenbook/anayo_mi html.
[40] See Campbell DMR reports for June and July 2025, available at https://mienviro michigan.gov/nsite/map/results/detail/6241586858212305105/documents. To access the July report, search for "MI0001422_2025-07-01_to_2025-07-31_DMR.pdf" in the "File" bar. The date of the entry is 8/13/2025. To access the June report, search for "MI0001422_2025-06-01_to_2025-06-30_DMR.pdf" in the "File" bar. The date of the entry is 7/14/2025.

37. In my professional opinion, and based on my 40 years of experience in coal boiler air emissions assessment and utility resource planning (as further discussed in Attachments A and B), the above-discussed emissions and discharge data show substantial and unnecessary environmental impact caused by operation of Campbell when lower-emitting, lower cost alternatives are available.

38. Thus, it continues to be my opinion that a coal unit would be the last alternative to consider for a peaking power application due in part to its high environmental impact.

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 San Diego, California.



Bill Powers, P.E.
Powers Engineering
4452 Park Blvd., Suite 209
San Diego, CA 92116

Attachment A

BILL POWERS, P.E.

PROFESSIONAL HISTORY

Powers Engineering, San Diego, CA 1994-
ENSR Consulting and Engineering, Camarillo, CA 1989-93
Naval Energy and Environmental Support Activity, Port Hueneme, CA 1982-87
U.S. Environmental Protection Agency, Research Triangle Park, NC 1980-81

EDUCATION

Bachelor of Science – Mechanical Engineering, Duke University
Master of Public Health – Environmental Sciences, University of North Carolina

PROFESSIONAL AFFILIATIONS

Registered Professional Mechanical Engineer, California (Certificate M24518)
Registered Professional Engineer, Missouri (Certificate 2018039156)
American Society of Mechanical Engineers
Institute of Electrical and Electronics Engineers

TECHNICAL SPECIALTIES

Forty years of experience in:

- Air quality and utility commission proceedings - expert witness
- Distributed solar photovoltaics (PV) siting and regional renewable energy planning
- Power plant cooling system conversion and air emission control assessments
- Combustion equipment permitting, testing and monitoring
- Air pollution control equipment retrofit design/performance testing
- Petroleum refinery air engineering and testing
- Latin America environmental project experience

RECENT AIR QUALITY AND UTILITY COMMISSION PROCEEDINGS

Compressor Station Gas Turbine Air Emission Controls. Assessed the air emission controls and siting issues related to two proposed pipeline compressor station projects in the vicinity of Nashville, Tennessee utilizing Solar Turbines, Inc Titan gas turbines. The result, based on application of a Reasonably Available Control Technology (RACT) requirement, was the reduction of the proposed air permit nitrogen oxides (NOx) emission limit from 25 parts per million (ppm) to 9 ppm.

Combined Heat and Power Plant Gas Turbine Air Emission Controls. Evaluated the air emission controls proposed for a combined heat and power (CHP) plant at Duke University that would utilize Solar Turbines, Inc Titan gas turbine. Applicant proposed a 25 ppm NO_x limit using dry low-NO_x combustion as Best Available Control Technology (BACT) in its Certificate of Public Convenience and Necessity (CPCN) application to the North Carolina Utilities Commission. Argued that NO_x BACT for the CHP plant should be use of selective catalytic reduction (SCR) to achieve a 2 ppm NO_x emission limit. Applicant withdrew its CPCN application.

SDG&E 36-Inch Transmission Pipeline. Expert witness for non-profit client advocating that existing 16-inch pipeline did not require replacement with new $600 million 36-inch pipeline. Underscored in testimony that SDG&E had recently completed extensive inline inspection of existing 16-inch pipeline and found that pipeline was in good condition for long-term operation at 512 psig transmission pressure. Demonstrated that reduction of pressure to 320 psig would not increase safety of existing pipeline, as ILI could no longer be done periodically at lower pressure. Commission accepted this reasoning and denied SDG&E's application.

Cove Point LNG Export Terminal. Expert witness in two separate administrative proceedings before the Maryland Public Service Commission, in 2014 and 2017, regarding air permit conditions for the proposed Cove Point LNG export. The plant site is located in a non-attainment area for ozone. Testimony addressed deficiencies in the proposed air emission limits and proposed control technology for combustion equipment – including gas turbines, auxiliary boilers, and flares, fugitive emission sources, and marine loading vapor recovery systems.

Corpus Christi LNG Expert Terminal. Expert witness in Texas Commission on Environmental Quality contested air permit proceeding in 2013 before the State Office of Administrative Hearings. Testimony addressed deficiencies in the proposed control technology for compressor-drive gas turbines, flares, and fugitive emission sources, and marine loading vapor recovery systems.

DISTRIBUTED SOLAR PV SITING AND REGIONAL RENEWABLE ENERGY PLANNING

Roadmap to 100 Percent Local Solar by 2030 in the City of San Diego. Author of the May 2020 *Roadmap to 100 Percent Local Solar Build-Out by 2030 in the City of San Diego* strategic energy plan for San Diego. The *Roadmap* outlines a strategy to maximize the use of solar energy and battery storage in the City of San Diego (City) to provide 100 percent clean electricity to all San Diegans by 2030. The City's Climate Action Plan sets a mandatory target of 100 percent clean electricity by 2035. The *Roadmap* describes how the City can best deliver lower-cost electricity and provide local job growth by choosing local solar power paired with battery storage, complemented by smart energy efficiency and demand response programs, to reach 100 percent clean energy.

North Carolina Clean Path 2025 Plan. Author of the August 2017 *North Carolina Clean Path 2025* strategic energy plan for North Carolina. *NC Clean Path 2025* implements local solar power, battery storage, and energy efficiency measures to rapidly replace fossil fuel-generated electricity in the state. The plan is substantially less costly than the $40 billion expansion of natural gas infrastructure, nuclear power, and transmission infrastructure being planned for North Carolina. Implementation of *NC Clean Path 2025* would reduce power generated by coal- and natural gas-fired plants by about 60 percent by 2025, and 100 percent by 2030. All in-state coal-fired plants would be closed and gas-fired plants would be used only for backup supply. Existing transmission and distribution infrastructure would be maintained and not expanded.

Bay Area Smart Energy 2020 Plan. Author of the March 2012 *Bay Area Smart Energy 2020* strategic energy plan for the nine-county region surrounding San Francisco Bay. This plan uses the zero net energy building targets in the *California Energy Efficiency Strategic Plan* as a framework to achieve a 60 percent reduction in GHG emissions from Bay Area electricity usage, and a 50 percent reduction in peak demand for grid electricity, by 2020. The 2020 targets in the plan include: 25 percent of detached homes and 20 percent of commercial buildings achieving zero net energy, adding 200 MW of community-scale microgrid battery storage and 400 MW of utility-scale battery storage, reduction in air conditioner loads by 50 percent through air conditioner cycling and targeted incentive funds to assure highest efficiency replacement units, and cooling system modifications to increase power output from The Geysers geothermal production zone in Sonoma County.

Solar PV technology selection and siting for SDG&E Solar San Diego project. Served as PV technology expert in California Public Utilities Commission proceeding to define PV technology and sites to be used in San Diego Gas & Electric (SDG&E) $250 million "Solar San Diego" project. Recommendations included: 1) prioritize use of roof-mounted thin-film PV arrays similar to the SCE urban PV program to maximize the installed PV capacity, 2) avoid tracking ground-mounted PV arrays due to high cost and relative lack of available land in the urban/suburban core, 3) and incorporate limited storage in fixed rooftop PV arrays to maximizing output during peak demand periods. Suitable land next to SDG&E substations capable of supporting 5 to 40 MW of PV (each) was also identified by Powers Engineering as a component of this project.

Rooftop PV alternative to natural gas-fired peaking gas turbines, Chula Vista. Served as PV technology expert in California Energy Commission (CEC) proceeding regarding the application of MMC Energy to build a 100 MW peaking gas turbine power plant in Chula Vista. Presented testimony that 100 MW of PV arrays in the Chula Vista area could provide the same level of electrical reliability on hot summer days as an equivalent amount of peaking gas turbine capacity at approximately the same cost of energy. The final decision issued by the CEC in the case denied the application in part due to failure of the applicant or CEC staff to thoroughly evaluate the PV alternative to the proposed turbines.

San Diego Smart Energy 2020 Plan. Author of October 2007 *San Diego Smart Energy 2020*, an energy plan that focuses on meeting the San Diego region's electric energy needs through accelerated integration of renewable and non-renewable distributed generation, in the form of combined heat and power (CHP) systems and solar photovoltaic (PV) systems. PV would meet approximately 28 percent of the San Diego region's electric energy demand in 2020. Annual energy demand would drop 20 percent in 2020 relative to 2003 through use all cost-effective energy efficiency measures. Existing utility-scale gas-fired generation would continue to be utilized to provide power at night, during cloudy weather, and for grid reliability support.

COOLING SYSTEM CONVERSION AND POWER PLANT EMISSION CONTROL ASSESSMENTS

Closed-Cycle Cooling Alternative at California Nuclear Plant.
Lead engineer on review of Bechtel assessment of wedgewire screens and closed-cycle cooling for Diablo Canyon nuclear plant. Demonstrated that wedgewire screens were not likely to be effective in substantially reducing entrainment at the site, and that lower cost closed-cycle retrofit alternatives could be utilized to allow a "cost reasonable" cooling tower retrofit. Plume-abated back-to-back cooling towers located in secondary parking lots to the southeast of the turbine building were identified as the most cost-effective alternative.

Closed-Cycle Cooling Alternative at Florida Nuclear Plant.
Evaluated closed cycle cooling tower feasibility assessment for Turkey Point Nuclear Units 3 and 4. Closed-cycle cooling would replace the existing closed-cycle cooling canals. Wet cooling towers for Units 3 and 4 are feasible and could be operational within four years of submittal of applications for the necessary permits.

Utility Boilers – Conversion of Existing Once-Through Cooled Boilers to Wet Towers, Parallel Wet-Dry Cooling, or Dry Cooling. Provided expert testimony and preliminary design for the conversion of four natural gas and/or coal-fired utility boilers (Unit 4, 235 MW; Unit 3, 135 MW; Unit 2, 65 MW; and Unit 1,65 MW) from once-through river water cooling to wet cooling towers, parallel wet-dry cooling, and dry cooling. Major design constraints were available land for location of retrofit cooling systems and need to maintain maximum steam turbine backpressure at or below 5.5 inches mercury to match performance capabilities of existing equipment. Approach temperatures of 12 ^{o}F and 13 ^{o}F were used for the wet towers. SPX Cooling Technologies F-488 plume-abated wet cells with six feet of packing were used to achieve approach temperatures of 12 ^{o}F and 13 ^{o}F. Annual energy penalty of wet tower retrofit designs is approximately 1 percent. Parallel wet-dry or dry cooling was determined to be technically feasible for Unit 3 based on straightforward access to the Unit 3 surface condenser and available land adjacent to the boiler.

Utility Boiler – Assessment of Air Cooling and Integrated Gasification/Combined Cycle for Proposed 500 MW Coal-Fired Plant. Provided expert testimony on the performance of air-cooling and IGCC relative to the conventional closed-cycle wet cooled, supercritical pulverized coal boiler proposed by the applicant. Steam Pro™ coal-fired power plant design software was used to model the proposed plant and evaluate the impacts on performance of air cooling and plume-abated wet cooling. Results indicated that a conservatively designed air-cooled condenser could maintain rated power output at the design ambient temperature of 90 ^{o}F. The IGCC comparative analysis indicated that unit reliability comparable to a conventional pulverized coal unit could be achieved by including a spare gasifier in the IGCC design, and that the slightly higher capital cost of IGCC was offset by greater thermal efficiency and reduced water demand and air emissions.

Utility Boiler – Assessment of Closed-Cycle Cooling Retrofit Cost for 1,200 MW Oil-Fired Plant. Prepared an assessment of the cost and feasibility of a closed-cycle wet tower retrofit for the 1,200 MW Roseton Generating Station. Determined that the cost to retrofit the Roseton plant with plume-abated closed-cycle wet cooling was well established based on cooling tower retrofit studies performed by the original owner (Central Hudson Gas & Electric Corp.) and subsequent regulatory agency critique of the cost estimate. Also determined that elimination of redundant and/or excessive budgetary line items in owners cost estimate brings the closed-cycle retrofit in line with expected costs for comparable new or retrofit plume-abated cooling tower applications.

Nuclear Power Plant – Assessment of Closed-Cycle Cooling Retrofit Cost for 2,000 MW Plant. Prepared an assessment of the cost and feasibility of a closed-cycle wet tower retrofit for the 2,000 MW Indian Point Generating Station. Determined that the most appropriate arrangement for the hilly site would be an inline plume-abated wet tower instead of the round tower configuration analyzed by the owner. Use of the inline configuration would allow placement of the towers at numerous sites on the property with little or need for blasting of bedrock, greatly reducing the cost of the retrofit. Also proposed an alternative circulating cooling water piping configuration to avoid the extensive downtime projected by the owner for modifications to the existing discharge channel.

Power Plant Dry Cooling Symposium – Chair and Organizer. Chair and organizer of the first symposium held in the U.S. (May 2002) that focused exclusively on dry cooling technology for power plants. Sessions included basic principles of wet and dry cooling systems, performance capabilities of dry cooling systems, case studies of specific installations, and reasons why dry cooling is the predominant form of cooling specified in certain regions of North America (Massachusetts, Nevada, northern Mexico).

Ameren Missouri Coal Units – Causes of Opacity and Opacity Reduction Alternatives. Lead engineer to assess the root causes of opacity exceedances and evaluate potential alternatives to eliminate opacity violations from the Labadie, Meramec, and Rush Island power plants.

Utility Boilers – Evaluation of Correlation Between Opacity and PM_{10} Emissions at Coal-Fired Plant. Provided expert testimony on whether correlation existed between mass PM_{10} emissions and opacity during opacity excursions at large coal-fired boiler in Georgia. EPA and EPRI technical studies were reviewed to assess the correlation of opacity and mass emissions during opacity levels below and above 20 percent. A strong correlation between opacity and mass emissions was apparent at a sister plant at opacities less than 20 percent. The correlation suggests that the opacity monitor correlation underestimates mass emissions at opacities greater than 20 percent, but may continue to exhibit a good correlation for the component of mass emissions in the PM_{10} size range.

IGCC as BACT for Air Emissions from Proposed 960 MW Coal Plant. Presented testimony on IGCC as BACT for air emissions reduction from 960 MW coal plant. Applicant received air permit for a pulverized coal plant to be equipped with a baghouse, wet scrubber, and wet ESP for air emissions control. Use of IGCC technology at the emission rates permitted for two recently proposed U.S. IGCC projects, and demonstrated in practice at a Japanese IGCC plant firing Chinese bituminous coal, would substantially reduce potential emissions of NO_x, SO_2, and PM. The estimated control cost-effectiveness of substituting IGCC for pulverized coal technology in this case was approximately $3,000/ton.

Analysis of Proposed Air Emission Limits for 600 MW Pulverized Coal Plant. Project engineer tasked with evaluating sufficiency of air emissions limits and control technologies for proposed 600 MW coal plant Arkansas. Determined that the applicant had: 1) not properly identified SO_2, sulfuric acid mist, and PM BACT control levels for the plant, and 2) improperly utilized an incremental cost effectiveness analysis to justify air emission control levels that did not represent BACT.

Eight Pulverized Coal Fired 900 MW Boilers – IGCC Alternative with Air Cooling. Provided testimony on integrated gasification combined cycle (IGCC) as a fully commercial coal-burning alternative to the pulverized coal (PC) technology proposed by TXU for eight 900 MW boilers in East Texas, and East Texas as an ideal location for CO2 sequestration due to presence of mature oilfield CO2 enhanced oil recovery opportunities and a deep saline aquifer underlying the entire region. Also presented testimony on the major increase in regional consumptive water use that would be caused by the evaporative cooling towers proposed for use in the PC plants, and that consumptive water use could be lowered by using IGCC with evaporative cooling towers or by using air-cooled condensers with PC or IGCC technology. TXU ultimately dropped plans to build the eight PC plants as a condition of a corporate buy-out.

Utility Boilers – Retrofit of SCR and FGD to Existing Coal-Fired Units.
Expert witness in successful effort to compel an existing coal-fired power plant located in Massachusetts to meet an accelerated NO_x and SO_2 emission control system retrofit schedule. Plant owner argued the installation of advanced NO_x and SO_2 control systems would generate > 1 ton/year of ancillary emissions, such as sulfuric acid mist, and that under Massachusetts Dept. of Environmental Protection regulation ancillary emissions > 1 ton/year would require a BACT evaluation and a two-year extension to retrofit schedule. Successfully demonstrated that no ancillary emissions would be generated if the retrofit NO_x and SO_2 control systems were properly sized and optimized. Plant owner committed to accelerated compliance schedule in settlement agreement.

Utility Boilers – Retrofit of SCR to Existing Natural Gas-Fired Units.
Lead engineer in successful representation of interests of California coastal city to prevent weakening of an existing countywide utility boiler NO_x rule. Weakening of NO_x rule would have allowed a merchant utility boiler plant located in the city to operate without installing selective catalytic reduction (SCR) NO_x control systems. This project required numerous appearances before the county air pollution control hearing board to successfully defend the existing utility boiler NO_x rule.

Biomass Plant NO_x and CO Air Emissions Control Evaluation. Lead engineer for evaluation of available nitrogen oxide (NO_x) and carbon monoxide (CO) controls for a 45 MW Aspen Power biomass plant in Texas where proponent had identified selective non-catalytic reduction (SNCR) for NO_x and good combustion practices for CO as BACT. Identified the use of tail-end SCR for NO_x control at several operational U.S. biomass plants, and oxidation catalyst in use at two of these plants for CO and VOC control, as BACT for the proposed biomass plant. Administrative law judge concurred in decision that SCR and oxidation catalyst is BACT. Developer added SCR and oxidation catalyst to project in subsequent settlement agreement.

Biomass Plant Air Emissions Control Consulting. Lead expert on biomass air emissions control systems for landowners that will be impacted by a proposed 50 MW biomass to be built by the local East Texas power cooperative. Public utility agreed to meet current BACT for biomass plants in Texas, SCR for NO_x and oxidation catalyst for CO, in settlement agreement with local landowners.

Combined-Cycle Power Plant Startup and Shutdown Emissions. Lead engineer for analysis of air permit startup and shutdown emissions minimization for combined-cycle power plant proposed for the San Francisco Bay Area. Original equipment was specified for baseload operation prior to suspension of project in early 2000s. Operational profile described in revised air permit was load following with potential for daily start/stop. Recommended that either fast start turbine technology be employed to minimize start/stop emissions or that "demonstrated in practice" operational and control software modifications be employed to minimize startup/shutdown emissions.

NON-WIRES ALTERNATIVES TO TRANSMISSION LINES

Ameren Missouri Mark Twain 345 kV Transmission Line. Responsible for evaluating: 1) the expected peak load growth of Ameren Missouri (MO) in general and in Northeast MO specifically over the next decade, 2) the likelihood of wind projects moving forward in the Northeast MO over the next decade, 3) the feasibility and cost of reconductoring with high capacity composite conductors the three 161 kV line segments that would experience NERC violations if 450 to 500 MW of wind power was constructed in Northeast MO, and 4) the feasibility and cost-effectiveness of substituting local solar for wind power to allow Ameren MO to meet its 2021 Renewable Portfolio Standard (RPS) obligation without building the proposed 345 kV transmission line or upgrading the three existing 161 kV lines interconnecting at the Adair Substation.

American Transmission Corporation Badger-Coulee 345 kV Line. Responsible for evaluating: 1) the expected peak load growth of Wisconsin utilities over the next decade, and 2) the feasibility and cost-effectiveness of alternatives including load management, energy efficiency, local solar, biogas, and energy storage as viable no-wires alternatives to the proposed ATC Badger-Coulee 345 kV transmission line.

San Diego Gas & Electric Wood Pole to Steel Pole Replacement Project.
Lead engineer assessing need and alternatives to replacement of existing wooden 69 kV poles with larger steel 69 kV poles as a response to the fire hazard potential of wooden poles in rural, high fire risk areas. Wooden poles in good condition and not a source of fire ignition. Utility would continue to shut off power to customers during low humidity, high wind conditions. Prepared alternative, solar with batteries for the ~10,000 affected customer meters, to allow customers to ride-through high fire hazard preventive grid power shut-offs at far less cost than replacing wood poles with steel poles.

San Diego Gas & Electric 500 kV Sunrise Transmission Line.
Lead engineer assessing the validity of load growth forecasts used by the utility to justify the need for the 500 kV line, and for developing a no-wires alternative, net-metered solar power with some battery support, to meet the identified reliability need at little or no net cost to the utility customer base.

COMBUSTION EQUIPMENT PERMITTING, TESTING AND MONITORING

EPRI Gas Turbine Power Plant Permitting Documents – Co-Author.
Co-authored two Electric Power Research Institute (EPRI) gas turbine power plant siting documents. Responsibilities included chapter on state-of-the-art air emission control systems for simple-cycle and combined-cycle gas turbines, and authorship of sections on dry cooling and zero liquid discharge systems.

Air Permits for 50 MW Peaker Gas Turbines – Six Sites Throughout California.
Responsible for preparing all aspects of air permit applications for five 50 MW FT-8 simple-cycle turbine installations at sites around California in response to emergency request by California state government for additional peaking power. Units were designed to meet 2.0 ppm NO_x using standard temperature SCR and innovative dilution air system to maintain exhaust gas temperature within acceptable SCR range. Oxidation catalyst is also used to maintain CO below 6.0 ppm.

Kauai 27 MW Cogeneration Plant – Air Emission Control System Analysis. Project manager to evaluate technical feasibility of SCR for 27 MW naphtha-fired turbine with once-through heat recovery steam generator. Permit action was stalled due to questions of SCR feasibility. Extensive analysis of the performance of existing oil-fired turbines equipped with SCR, and bench-scale tests of SCR applied to naphtha-fired turbines, indicated that SCR would perform adequately. Urea was selected as the SCR reagent given the local availability of urea. Unit is first known application of urea-injected SCR on a naphtha-fired turbine.

Microturbines – Ronald Reagan Library, Ventura County, California.
Project manager and lead engineer or preparation of air permit applications for microturbines and standby boilers. The microturbines drive the heating and cooling system for the library. The microturbines are certified by the manufacturer to meet the 9 ppm NO_x emission limit for this equipment. Low-NO_x burners are BACT for the standby boilers.

Hospital Cogeneration Microturbines – South Coast Air Quality Management District.
Project manager and lead engineer for preparation of air permit application for three microturbines at hospital cogeneration plant installation. The draft Authority To Construct (ATC) for this project was obtained two weeks after submittal of the ATC application. 30-day public notification was required due to the proximity of the facility to nearby schools. The final ATC was issued two months after the application was submitted, including the 30-day public notification period.

Gas Turbine Cogeneration – South Coast Air Quality Management District. Project manager and lead engineer for preparation of air permit application for two 5.5 MW gas turbines in cogeneration configuration for county government center. The turbines are equipped with selective catalytic reduction (SCR) and oxidation catalyst to comply with SCAQMD BACT requirements. Aqueous urea is used as the SCR reagent to avoid trigger hazardous material storage requirements. The NO_x and CO continuous emissions monitoring systems are covered by a separate permit.

Peaker Gas Turbines – Evaluation of NO_x Control Options for Installations in San Diego County.
Lead engineer for evaluation of NO_x control options available for 1970s vintage simple-cycle gas turbines proposed for peaker sites in San Diego County. Dry low-NO_x (DLN) combustors, catalytic combustors, high-temperature SCR, and NO_x absorption/conversion ($SCONO_x$) were evaluated for each candidate turbine make/model. High-temperature SCR was selected as the NOx control option to meet a 5 ppm NO_x emission requirement.

Hospital Cogeneration Plant Gas Turbines – San Joaquin Valley Unified Air Pollution Control District.
Project manager and lead engineer for preparation of air permit application and Best Available Control Technology (BACT) evaluation for hospital cogeneration plant installation. The BACT included the review of DLN combustors, catalytic combustors, high-temperature SCR and $SCONO_x$. DLN combustion followed by high temperature SCR was selected as the NO_x control system for this installation. The high temperature SCR is located upstream of the heat recovery steam generator (HRSG) to allow the diversion of exhaust gas around the HRSG without compromising the effectiveness of the NO_x control system.

1,000 MW Coastal Combined-Cycle Power Plant – Feasibility of Dry Cooling.
Expert witness in on-going effort to require use of dry cooling on proposed 1,000 MW combined-cycle "repower" project at site of an existing 1,000 MW utility boiler plant. Project proponent argued that site was two small for properly sized air-cooled condenser (ACC) and that use of ACC would cause 12-month construction delay. Demonstrated that ACC could easily be located on the site by splitting total of up to 80 cells between two available locations at the site. Also demonstrated that an ACC optimized for low height and low noise would minimize or eliminate proponent claims of negative visual and noise impacts.

Industrial Cogeneration Plant Gas Turbines – Upgrade of Turbine Power Output.
Project manager and lead engineer for preparation of Best Available Control Technology (BACT) evaluation for proposed gas turbine upgrade. The BACT included the review of DLN combustors, catalytic combustors, high-, standard-, and low-temperature SCR, and $SCONO_x$. Successfully negotiated air permit that allowed facility to initially install DLN combustors and operate under a NO_x plantwide "cap." Within two major turbine overhauls, or approximately eight years, the NO_x emissions per turbine must be at or below the equivalent of 5 ppm. The 5 ppm NO_x target will be achieved through technological in-combustor NO_x control such as catalytic combustion, or SCR or SCR equivalent end-of-pipe NO_x control technologies if catalytic combustion is not available.

Gas Turbines – Modification of RATA Procedures for Time-Share CEM.
Project manager and lead engineer for the development of alternate CO continuous emission monitor (CEM) Relative Accuracy Test Audit (RATA) procedures for time-share CEM system serving three 7.9 MW turbines located in San Diego. Close interaction with San Diego APCD and EPA Region 9 engineers was required to

receive approval for the alternate CO RATA standard. The time-share CEM then passed the annual RATA without problems as a result of changes to some CEM hardware and the more flexible CO RATA standard.

Gas Turbines – Evaluation of NO_x Control Technology Performance. Lead engineer for performance review of dry low-NO_x combustors, catalytic combustors, high-, standard-, and low-temperature selective catalytic reduction (SCR), and NO_x absorption/conversion ($SCONO_x$). Major turbine manufacturers and major manufacturers of end-of-pipe NO_x control systems for gas turbines were contacted to determine current cost and performance of NO_x control systems. A comparison of 1993 to 1999 "$/kwh" and "$/ton" cost of these control systems was developed in the evaluation.

Lead engineer for evaluation for proposed combined cycle gas turbine NO_x and CO control systems. Project was in litigation over contract terms, and there was concern that the GE Frame 7FA turbine could not meet the 3 ppm NO_x permit limit using a conventional combustor with water injection followed by SCR. Operations personnel at GE Frame 7FA installatins around the country were interviewed, along with principal SCR vendors, to corroborate that the installation could continuously meet the 3 ppm NO_x limit.

Gas Turbines – Title V "Presumptively Approvable" Compliance Assurance Monitoring Protocol. Project manager and lead engineer for the development of a "presumptively approval" NO_x parametric emissions monitoring system (PEMS) protocol for industrial gas turbines. "Presumptively approvable" means that any gas turbine operator selecting this monitoring protocol can presume it is acceptable to the U.S. EPA. Close interaction with the gas turbine manufacturer's design engineering staff and the U.S. EPA Emissions Measurement Branch (Research Triangle Park, NC) was required to determine modifications necessary to the current PEMS to upgrade it to "presumptively approvable" status.

Environmental Due Diligence Review of Gas Turbine Sites – Mexico. Task leader to prepare regulatory compliance due diligence review of Mexican requirements for gas turbine power plants. Project involves eleven potential sites across Mexico, three of which are under construction. Scope involves identification of all environmental, energy sales, land use, and transportation corridor requirements for power projects in Mexico. Coordinator of Mexican environmental subcontractors gathering on-site information for each site, and translator of Spanish supporting documentation to English.

Development of Air Emission Standards for Gas Turbines - Peru. Served as principal technical consultant to the Peruvian Ministry of Energy in Mines (MEM) for the development of air emission standards for Peruvian gas turbine power plants. All major gas turbine power plants in Peru are currently using water injection to increase turbine power output. Recommended that 42 ppm on natural gas and 65 ppm on diesel (corrected to 15% O_2) be established as the NO_x limit for existing gas turbine power plants. These limits reflect NO_x levels readily achievable using water injection at high load. Also recommended that new gas turbine sources be subject to a BACT review requirement.

Gas Turbines – Title V Permit Templates. Lead engineer for the development of standardized permit templates for approximately 100 gas turbines operated by the oil and gas industry in the San Joaquin Valley. Emissions limits and monitoring requirements were defined for units ranging from GE Frame 7 to Solar Saturn turbines. Stand-alone templates were developed based on turbine size and NO_x control equipment. NO_x utilized in the target turbine population ranged from water injection alone to water injection combined with SCR.

Gas Turbines – Evaluation of NO_x, SO_2 and PM Emission Profiles. Performed a comparative evaluation of the NO_x, SO_2 and particulate (PM) emission profiles of principal utility-scale gas turbines for an independent power producer evaluating project opportunities in Latin America. All gas turbine models in the 40 MW to 240 MW range manufactured by General Electric, Westinghouse, Siemens and ABB were included in the evaluation.

Stationary Internal Combustion Engine (ICE) RACT/BARCT Evaluation. Lead engineer for evaluation of retrofit NO_x control options available for the oil and gas production industry gas-fired ICE population in the San Joaquin Valley affected by proposed RACT and BARCT emission limits. Evaluation centered on lean-burn compressor engines under 500 bhp, and rich-burn constant and cyclically loaded (rod pump) engines under 200 bhp. The results of the evaluation indicated that rich burn cyclically-loaded rod pump engines comprised 50 percent of the affected ICE population, though these ICEs accounted for only 5 percent of the uncontrolled gas-fired stationary ICE NO_x emissions. Recommended retrofit NO_x control strategies included: air/fuel ratio adjustment for rod pump ICEs, Non-selective catalytic reduction (NSCR) for rich-burn, constant load ICEs, and "low emission" combustion modifications for lean burn ICEs.

Development of Air Emission Standards for Stationary ICEs - Peru. Served as principal technical consultant to the Peruvian Ministry of Energy in Mines (MEM) for the development of air emission standards for Peruvian stationary ICE power plants. Draft 1997 World Bank NO_x and particulate emission limits for stationary ICE power plants served as the basis for proposed MEM emission limits. A detailed review of ICE emissions data provided in PAMAs submitted to the MEM was performed to determine the level of effort that would be required by Peruvian industry to meet the proposed NO_x and particulate emission limits. The draft 1997 WB emission limits were revised to reflect reasonably achievable NO_x and particulate emission limits for ICEs currently in operation in Peru.

Air Toxics Testing of Natural Gas-Fired ICEs. Project manager for test plan/test program to measure volatile and semi-volatile organic air toxics compounds from fourteen gas-fired ICEs used in a variety of oil and gas production applications. Test data was utilized by oil and gas production facility owners throughout California to develop accurate ICE air toxics emission inventories.

AIR ENGINEERING/AIR TESTING PROJECT EXPERIENCE – GENERAL

Reverse Air Fabric Filter Retrofit Evaluation – Coal-Fired Boiler. Lead engineer for upgrade of reverse air fabric filters serving coal-fired industrial boilers. Fluorescent dye injected to pinpoint broken bags and damper leaks. Corrosion of pneumatic actuators serving reverse air valves and inadequate insulation identified as principal causes of degraded performance.

Pulse-Jet Fabric Filter Performance Evaluation – Gold Mine. Lead engineer on upgrade of pulse-jet fabric filter and associated exhaust ventilation system serving an ore-crushing facility at a gold mine. Fluorescent dye used to identify bag collar leaks, and modifications were made to pulse air cycle time and duration. This marginal source was in compliance at 20 percent of emission limit following completion of repair work.

Pulse-Jet Fabric Filter Retrofit - Gypsum Calciner. Lead engineer on upgrade of pulse-jet fabric filter controlling particulate emissions from a gypsum calciner. Recommendations included a modified bag clamping mechanism, modified hopper evacuation valve assembly, and changes to pulse air cycle time and pulse duration.

Wet Scrubber Retrofit – Plating Shop. Project engineer on retrofit evaluation of plating shop packed-bed wet scrubbers failing to meet performance guarantees during acceptance trials, due to excessive mist carryover. Recommendations included relocation of the mist eliminator (ME), substitution of the original chevron blade ME with a mesh pad ME, and use of higher density packing material to improve exhaust gas distribution. Wet scrubbers passed acceptance trials following completion of recommended modifications.

Electrostatic Precipitator (ESP) Retrofit Evaluation – MSW Boiler. Lead engineer for retrofit evaluation of single field ESP on a municipal solid waste (MSW) boiler. Recommendations included addition of automated power controller, inlet duct turning vanes, and improved collecting plate rapping system.

ESP Electric Coil Rapper Vibration Analysis Testing - Coal-Fired Boiler. Lead engineer for evaluation of ESP rapper effectiveness test program on three field ESP equipped with "magnetically induced gravity return" (MIGR) rappers. Accelerometers were placed in a grid pattern on ESP collecting plates to determine maximum

instantaneous plate acceleration at a variety of rapper power setpoints. Testing showed that the rappers met performance specification requirements.

Aluminum Remelt Furnace Particulate Emissions Testing. Project manager and lead engineer for high temperature (1,600 ºF) particulate sampling of a natural gas-fired remelt furnace at a major aluminum rolling mill. Objectives of test program were to: 1) determine if condensable particulate was present in stack gases, and 2) to validate the accuracy of the in-stack continuous opacity monitor (COM). Designed and constructed a customized high temperature (inconel) PM_{10}/Mtd 17 sampling assembly for test program. An onsite natural gas-fired boiler was also tested to provide comparative data for the condensable particulate portion of the test program. Test results showed that no significant levels of condensable particulate in the remelt furnace exhaust gas, and indicated that the remelt furnace and boiler had similar particulate emission rates. Test results also showed that the COM was accurate.

Aluminum Remelt Furnace CO and NO_x Testing. Project manager and lead engineer for continuous week-long testing of CO and NO_x emissions from aluminum remelt furnace. Objective of test program was to characterize CO and NO_x emissions from representative remelt furnace for use in the facility's criteria pollution emissions inventory. A TECO Model 48 CO analyzer and a TECO Model 10 NO_x analyzer were utilized during the test program to provide $\pm$1 ppm measurement accuracy, and all test data was recorded by an automated data acquisition system.

PETROLEUM REFINERY AIR ENGINEERING/TESTING EXPERIENCE

Big West Refinery Expansion EIS. Lead engineer on comparative cost analysis of proposed wet cooling tower and fin-fan air cooler for process cooling water for the proposed clean fuels expansion project at the Big West Refinery in Bakersfield, California. Selection of the fin-fin air-cooler would eliminate all consumptive water use and wastewater disposal associated with the cooling tower. Air emissions of VOC and PM_{10} would be reduced with the fin-fan air-cooler even though power demand of the air-cooler is incrementally higher than that of the cooling tower. Fin-fan air-coolers with approach temperatures of 10 ºF and 20 ºF were evaluated. The annualized cost of the fin-fin air-cooler with a 20 ºF approach temperature is essentially the same as that of the cooling tower when the cost of all ancillary cooling tower systems are considered.

Criteria and Air Toxic Pollutant Emissions Inventory for Proposed Refinery Modifications. Project manager and technical lead for development of baseline and future refinery air emissions inventories for process modifications required to produce oxygenated gasoline and desulfurized diesel fuel at a California refinery. State of the art criteria and air toxic pollutant emissions inventories for refinery point, fugitive and mobile sources were developed. Point source emissions estimates were generated using onsite criteria pollutant test data, onsite air toxics test data, and the latest air toxics emission factors from the statewide refinery air toxics inventory database. The fugitive volatile organic compound (VOC) emissions inventories were developed using the refinery's most recent inspection and maintenance (I&M) monitoring program test data to develop site-specific component VOC emission rates. These VOC emission rates were combined with speciated air toxics test results for the principal refinery process streams to produce fugitive VOC air toxics emission rates. The environmental impact report (EIR) that utilized this emission inventory data was the first refinery "Clean Fuels" EIR approved in California.

Development of Air Emission Standards for Petroleum Refinery Equipment - Peru. Served as principal technical consultant to the Peruvian Ministry of Energy in Mines (MEM) for the development of air emission standards for Peruvian petroleum refineries. The sources included in the scope of this project included: 1) SO_2 and NO_x refinery heaters and boilers, 2) desulfurization of crude oil, particulate and SO_2 controls for fluid catalytic cracking units (FCCU), 3) VOC and CO emissions from flares, 4) vapor recovery systems for marine unloading, truck loading, and crude oil/refined products storage tanks, and 5) VOC emissions from process fugitive sources such as pressure relief valves, pumps, compressors and flanges. Proposed emission limits were developed for new and existing refineries based on a thorough evaluation of the available air emission control technologies for the affected refinery sources. Leading vendors of refinery control technology, such as John Zink and Exxon Research, provided estimates of retrofit costs for the largest Peruvian refinery, La Pampilla,

located in Lima. Meetings were held in Lima with refinery operators and MEM staff to discuss the proposed emission limits and incorporate mutually agreed upon revisions to the proposed limits for existing Peruvian refineries.

Air Toxic Pollutant Emissions Inventory for Existing Refinery. Project manager and technical lead for air toxic pollutant emissions inventory at major California refinery. Emission factors were developed for refinery heaters, boilers, flares, sulfur recovery units, coker deheading, IC engines, storage tanks, process fugitives, and catalyst regeneration units. Onsite source test results were utilized to characterize emissions from refinery combustion devices. Where representative source test results were not available, AP-42 VOC emission factors were combined with available VOC air toxics speciation profiles to estimate VOC air toxic emission rates. A risk assessment based on this emissions inventory indicated a relatively low health risk associated with refinery operations. Benzene, 1,3-butadiene and PAHs were the principal health risk related pollutants emitted.

Air Toxics Testing of Refinery Combustion Sources. Project manager for comprehensive air toxics testing program at a major California refinery. Metals, Cr^{+6}, PAHs, H_2S and speciated VOC emissions were measured from refinery combustion sources. High temperature Cr^{+6} stack testing using the EPA Cr^{+6} test method was performed for the first time in California during this test program. Representatives from the California Air Resources Board source test team performed simultaneous testing using ARB Method 425 (Cr^{+6}) to compare the results of EPA and ARB Cr^{+6} test methodologies. The ARB approved the test results generated using the high temperature EPA Cr^{+6} test method.

Air Toxics Testing of Refinery Fugitive Sources. Project manager for test program to characterize air toxic fugitive VOC emissions from fifteen distinct process units at major California refinery. Gas, light liquid, and heavy liquid process streams were sampled. BTXE, 1,3-butadiene and propylene concentrations were quantified in gas samples, while BTXE, cresol and phenol concentrations were measured in liquid samples. Test results were combined with AP-42 fugitive VOC emission factors for valves, fittings, compressors, pumps and PRVs to calculate fugitive air toxics VOC emission rates.

OIL AND GAS PRODUCTION AIR ENGINEERING/TESTING EXPERIENCE

Air Toxics Testing of Oil and Gas Production Sources. Project manager and lead engineer for test plan/test program to determine VOC removal efficiency of packed tower scrubber controlling sulfur dioxide emissions from a crude oil-fired steam generator. Ratfisch 55 VOC analyzers were used to measure the packed tower scrubber VOC removal efficiency. Tedlar bag samples were collected simultaneously to correlate BTX removal efficiency to VOC removal efficiency. This test was one of hundreds of air toxics tests performed during this test program for oil and gas production facilities from 1990 to 1992. The majority of the volatile air toxics analyses were performed at in-house laboratory. Project staff developed thorough familiarity with the applications and limitations of GC/MS, GC/PID, GC/FID, GC/ECD and GC/FPD. Tedlar bags, canisters, sorbent tubes and impingers were used during sampling, along with isokinetic tests methods for multiple metals and PAHs.

Air Toxics Testing of Glycol Reboiler – Gas Processing Plant. Project manager for test program to determine emissions of BTXE from glycol reboiler vent at gas processing facility handling 12 MM/cfd of produced gas. Developed innovative test methods to accurately quantify BTXE emissions in reboiler vent gas.
Air Toxics Emissions Inventory Plan. Lead engineer for the development of generic air toxics emission estimating techniques (EETs) for oil and gas production equipment. This project was performed for the Western States Petroleum Association in response to the requirements of the California Air Toxics "Hot Spots" Act. EETs were developed for all point and fugitive oil and gas production sources of air toxics, and the specific air toxics associated with each source were identified. A pooled source emission test methodology was also developed to moderate the cost of source testing required by the Act.

Fugitive NMHC Emissions from TEOR Production Field. Project manager for the quantification of fugitive Nonmethane hydrocarbon (NMHC) emissions from a thermally enhanced oil recovery (TEOR) oil production field in Kern County, CA. This program included direct measurement of NMHC concentrations in storage tank

vapor headspace and the modification of available NMHC emission factors for NMHC-emitting devices in TEOR produced gas service, such as wellheads, vapor trunklines, heat exchangers, and compressors. Modification of the existing NMHC emission factors was necessary due to the high concentration of CO_2 and water vapor in TEOR produced gases.

Fugitive Air Emissions Testing of Oil and Gas Production Fields. Project manager for test plan/test program to determine VOC and air toxics emissions from oil storage tanks, wastewater storage tanks and produced gas lines. Test results were utilized to develop comprehensive air toxics emissions inventories for oil and gas production companies participating in the test program.

Oil and Gas Production Field – Air Emissions Inventory and Air Modeling. Project manager for oil and gas production field risk assessment. Project included review and revision of the existing air toxics emission inventory, air dispersion modeling, and calculation of the acute health risk, chronic non-carcinogenic risk and carcinogenic risk of facility operations. Results indicated that fugitive H_2S emissions from facility operations posed a potential health risk at the facility fenceline.

TITLE V PERMIT APPLICATION/MONITORING PLAN EXPERIENCE

Title V Permit Application – San Diego County Industrial Facility. Project engineer tasked with preparing streamlined Title V operating permit for U.S. Navy facilities in San Diego. Principal emission units included chrome plating, lead furnaces, IC engines, solvent usage, aerospace coating and marine coating operations. For each device category in use at the facility, federal MACT requirements were integrated with District requirements in user friendly tables that summarized permit conditions and compliance status.

Title V Permit Application Device Templates - Oil and Gas Production Industry. Project manager and lead engineer to prepare Title V permit application "templates" for the Western States Petroleum Association (WSPA). The template approach was chosen by WSPA to minimize the administrative burden associated with listing permit conditions for a large number of similar devices located at the same oil and gas production facility. Templates are being developed for device types common to oil and gas production operations. Device types include: boilers, steam generators, process heaters, gas turbines, IC engines, fixed-roof storage tanks, fugitive components, flares, and cooling towers. These templates will serve as the core of Title V permit applications prepared for oil and gas production operations in California.

Title V Permit Application - Aluminum Rolling Mill. Project manager and lead engineer for Title V permit application prepared for largest aluminum rolling mill in the western U.S. Responsible for the overall direction of the permit application project, development of a monitoring plan for significant emission units, and development of a hazardous air pollutant (HAP) emissions inventory. The project involved extensive onsite data gathering, frequent interaction with the plant's technical and operating staff, and coordination with legal counsel and subcontractors. The permit application was completed on time and in budget.

Title V Model Permit - Oil and Gas Production Industry. Project manager and lead engineer for the comparative analysis of regional and federal requirements affecting oil and gas production industry sources located in the San Joaquin Valley. Sources included gas turbines, IC engines, steam generators, storage tanks, and process fugitives. From this analysis, a model applicable requirements table was developed for a sample device type (storage tanks) that covered the entire population of storage tanks operated by the industry. The U.S. EPA has tentatively approved this model permit approach, and work is ongoing to develop comprehensive applicable requirements tables for each major category of sources operated by the oil and gas industry in the San Joaquin Valley.

Title V Enhanced Monitoring Evaluation of Oil and Gas Production Sources. Lead engineer to identify differences in proposed EPA Title V enhanced monitoring protocols and the current monitoring requirements for oil and gas production sources in the San Joaquin Valley. The device types evaluated included: steam generators, stationary ICEs, gas turbines, fugitives, fixed roof storage tanks, and thermally enhanced oil recovery (TEOR) well vents. Principal areas of difference included: more stringent Title V O&M requirements

for parameter monitors (such as temperature, fuel flow, and O_2), and more extensive Title V recordkeeping requirements.

RACT/BARCT/BACT EVALUATIONS

RACT/BARCT Reverse Jet Scrubber/Fiberbed Mist Eliminator Retrofit Evaluation. Project manager and lead engineer on project to address the inability of existing wet electrostatic precipitators (ESPs) and atomized mist scrubbers to adequately remove low concentration submicron particulate from high volume recovery boiler exhaust gas at the Alaska Pulp Corporation mill in Sitka, AK. The project involved thorough on-site inspections of existing control equipment, detailed review of maintenance and performance records, and a detailed evaluation of potential replacement technologies. These technologies included a wide variety of scrubbing technologies where manufacturers claimed high removal efficiencies on submicron particulate in high humidity exhaust gas. Packed tower scrubbers, venturi scrubbers, reverse jet scrubbers, fiberbed mist eliminators and wet ESPs were evaluated. Final recommendations included replacement of atomized mist scrubber with reverse jet scrubber and upgrading of the existing wet ESPs. The paper describing this project was published in the May 1992 TAPPI Journal.

Aluminum Smelter RACT Evaluation - Prebake. Project manager and technical lead for CO and PM_{10} RACT evaluation for prebake facility. Retrofit control options for CO emissions from the anode bake furnace, potline dry scrubbers and the potroom roof vents were evaluated. PM_{10} emissions from the coke kiln, potline dry scrubbers, potroom roof vents, and miscellaneous potroom fugitive sources were addressed. Four CO control technologies were identified as technologically feasible for potline CO emissions: potline current efficiency improvement through the addition of underhung busswork and automated puncher/feeders, catalytic incineration, recuperative incineration and regenerative incineration. Current efficiency improvement was identified as probable CO RACT if onsite test program demonstrated the effectiveness of this approach. Five PM_{10} control technologies were identified as technologically feasible: increased potline hooding efficiency through redesign of shields, the addition of a dense-phase conveying system, increased potline air evacuation rate, wet scrubbing of roof vent emissions, and fabric filter control of roof vent emissions.

RACT/BACT Testing/Evaluation of PM_{10} Mist Eliminators on Five-Stand Cold Mill. Project manager and lead engineer for fiberbed mist eliminator and mesh pad mist eliminator comparative pilot test program on mixed phase aerosol (PM_{10})/gaseous hydrocarbon emissions from aluminum high speed cold rolling mill. Utilized modified EPA Method 5 sampling train with portion of sample gas diverted (after particulate filter) to Ratfisch 55 VOC analyzer. This was done to permit simultaneous quantification of aerosol and gaseous hydrocarbon emissions in the exhaust gas. The mesh pad mist eliminator demonstrated good control of PM_{10} emissions, though test results indicated that the majority of captured PM_{10} evaporated in the mesh pad and was emitted as VOC.

Aluminum Remelt Furnace/Rolling Mill RACT Evaluations. Lead engineer for comprehensive CO and PM_{10} RACT evaluation for the largest aluminum sheet and plate rolling mill in western U.S. Significant sources of CO emissions from the facility included the remelt furnaces and the coater line. The potential CO RACT options for the remelt furnaces included: enhanced maintenance practices, preheating combustion air, installation of fully automated combustion controls, and energy efficiency modifications.

BARCT Low NO_x Burner Conversion – Industrial Boilers. Lead engineer for evaluation of low NO_x burner options for natural gas-fired industrial boilers. Also evaluated methanol and propane as stand-by fuels to replace existing diesel stand-by fuel system. Evaluated replacement of steam boilers with gas turbine co-generation system.

BACT Packed Tower Scrubber/Mist Eliminator Performance Evaluations. Project manager and lead engineer for Navy-wide plating shop air pollution control technology evaluation and emissions testing program. Mist eliminators and packed tower scrubbers controlling metal plating processes, which included hard chrome, nickel, copper, cadmium and precious metals plating, were extensively tested at three Navy plating shops.

Chemical cleaning and stripping tanks, including hydrochloric acid, sulfuric acid, chromic acid and caustic, were also tested. The final product of this program was a military design specification for plating and chemical cleaning shop air pollution control systems. The hydrochloric acid mist sampling procedure developed during this program received a protected patent.

BACT Packed Tower Scrubber/UV Oxidation System Pilot Test Program. Technical advisor for pilot test program of packed tower scrubber/ultraviolet (UV) light VOC oxidation system controlling VOC emissions from microchip manufacturing facility in Los Angeles. The testing was sponsored in part by the SCAQMD's Innovative Technology Demonstration Program, to demonstrate this innovative control technology as BACT for microchip manufacturing operations. The target compounds were acetone, methylethylketone (MEK) and 1,1,1-trichloroethane, and compound concentrations ranged from 10-100 ppmv. The single stage packed tower scrubber consistently achieved greater than 90% removal efficiency on the target compounds. The residence time required in the UV oxidation system for effective oxidation of the target compounds proved significantly longer than the residence time predicted by the manufacturer.

BACT Pilot Testing of Venturi Scrubber on Gas/Aerosol VOC Emission Source. Technical advisor for project to evaluate venturi scrubber as BACT for mixed phase aerosol/gaseous hydrocarbon emissions from deep fat fryer. Venturi scrubber demonstrated high removal efficiency on aerosol, low efficiency on VOC emissions. A number of VOC tests indicated negative removal efficiency. This anomaly was traced to a high hydrocarbon concentration in the scrubber water. The pilot unit had been shipped directly to the jobsite from another test location by the manufacturer without any cleaning or inspection of the pilot unit.

Pulp Mill Recovery Boiler BACT Evaluation. Lead engineer for BACT analysis for control of SO_2, NO_x, CO, TNMHC, TRS and particulate emissions from the proposed addition of a new recovery furnace at a kraft pulp mill in Washington. A "top down" approach was used to evaluate potential control technologies for each of the pollutants considered in the evaluation.

Air Pollution Control Equipment Design Specification Development. Lead engineer for the development of detailed Navy design specifications for wet scrubbers and mist eliminators. Design specifications were based on field performance evaluations conducted at the Long Beach Naval Shipyard, Norfolk Naval Shipyard, and Jacksonville Naval Air Station. This work was performed for the U.S. Navy to provide generic design specifications to assist naval facility engineering divisions with air pollution control equipment selection. Also served as project engineer for the development of Navy design specifications for ESPs and fabric filters.

CONTINUOUS EMISSION MONITOR (CEM) PROJECT EXPERIENCE

Process Heater CO and NO_x CEM Relative Accuracy Testing. Project manager and lead engineer for process heater CO and NO_x analyzer relative accuracy test program at petrochemical manufacturing facility. Objective of test program was to demonstrate that performance of onsite CO and NO_x CEMs was in compliance with U.S. EPA "Boiler and Industrial Furnace" hazardous waste co-firing regulations. A TECO Model 48 CO analyzer and a TECO Model 10 NO_x analyzer were utilized during the test program to provide $\pm$1 ppm measurement accuracy, and all test data was recorded by an automated data acquisition system. One of the two process heater CEM systems tested failed the initial test due to leaks in the gas conditioning system. Troubleshooting was performed using O_2 analyzers, and the leaking component was identified and replaced. This CEM system met all CEM relative accuracy requirements during the subsequent retest.

Performance Audit of NO_x and SO_2 CEMs at Coal-Fired Power Plant. Lead engineer on system audit and challenge gas performance audit of NO_x and SO_2 CEMs at a coal-fired power plant in southern Nevada. Dynamic and instrument calibration checks were performed on the CEMs. A detailed visual inspection of the CEM system, from the gas sampling probes at the stack to the CEM sample gas outlet tubing in the CEM trailer, was also conducted. The CEMs passed the dynamic and instrument calibration requirements specified in EPA's Performance Specification Test - 2 (NO_x and SO_2) alternative relative accuracy requirements.

LATIN AMERICA ENVIRONMENTAL PROJECT EXPERIENCE

Assessment of operational deficiencies of Camisa pipeline – Peru. Project leader of multi-year assessment of root causes of ruptures on Camisea 14-inch natural gas liquids pipeline for non-profit client. Determined that primary causes of hurried construction in difficult and unstable terrain, unstable right-of-way in the jungle sector due to inadequate erosion control practices, and inadequate pipe wall thickness to withstand external lateral forces. Two assessments were developed during the course of the project documenting deficiencies and recommending remedial actions.

Evaluation of U.S.-Mexico Border Region Copper Smelter Compliance with Treaty Obligations – Mexico. Project manager and lead engineer to evaluate compliance of U.S. and Mexican border region copper smelters with the SO_2 monitoring, recordkeeping and reporting requirements in Annex IV [Copper Smelters] of the La Paz Environmental Treaty. Identified potential problems with current ambient and stack monitoring practices that could result in underestimating the impact of SO_2 emissions from some of these copper smelters. Identified additional source types, including hazardous waste incinerators and power plants, that should be considered for inclusion in the La Paz Treaty process.

Development of Air Emission Limits for ICE Cogeneration Plant - Panamá. Lead engineer assisting U.S. cogeneration plant developer to permit an ICE cogeneration plant at a hotel/casino complex in Panama. Recommended the use of modified draft World Bank NO_x and PM limits for ICE power plants. The modification consisted of adding a thermal efficiency factor adjustment to the draft World Bank NO_x and PM limits. These proposed ICE emission limits are currently being reviewed by Panamanian environmental authorities.

Mercury Emissions Inventory for Stationary Sources in Northern Mexico. Project manager and lead engineer to estimate mercury emissions from stationary sources in Northern Mexico. Major potential sources of mercury emissions include solid- and liquid-fueled power plants, cement kilns co-firing hazardous waste, and non-ferrous metal smelters. Emission estimates were provided for approximately eighty of these sources located in Northern Mexico. Coordinated efforts of two Mexican subcontractors, located in Mexico City and Hermosillo, to obtain process throughput data for each source included in the inventory.

Translation of U.S. EPA Scrap Tire Combustion Emissions Estimation Document – Mexico. Evaluated the Translated a U.S. EPA scrap tire combustion emissions estimation document from English to Spanish for use by Latin American environmental professionals.

Environmental Audit of Aluminum Production Facilities – Venezuela. Evaluated the capabilities of existing air, wastewater and solid/hazardous waste control systems used by the aluminum industry in eastern Venezuela. This industry will be privatized in the near future. Estimated the cost to bring these control systems into compliance with air, wastewater and solid/hazardous waste standards recently promulgated in Venezuela. Also served as technical translator for team of U.S. environmental engineers involved in the due diligence assessment.

Assessment of Environmental Improvement Projects – Chile and Peru. Evaluated potential air, water, soil remediation and waste recycling projects in Lima, Peru and Santiago, Chile for feasibility study funding by the U.S. Trade and Development Agency. Project required onsite interaction with in-country decisionmakers (in Spanish). Projects recommended for feasibility study funding included: 1) an air quality technical support project for the Santiago, Chile region, and 2) soil remediation/metals recovery projects at two copper mine/smelter sites in Peru.

Air Pollution Control Training Course – Mexico. Conducted two-day Spanish language air quality training course for environmental managers of assembly plants in Mexicali, Mexico. Spanish-language course manual prepared by Powers Engineering. Practical laboratory included training in use of combustion gas analyzer, flame ionization detector (FID), photoionization detector (PID), and occupational sampling.

Stationary Source Emissions Inventory – Mexico. Developed a comprehensive air emissions inventory for stationary sources in Nogales, Sonora. This project requires frequent interaction with Mexican state and federal environmental authorities. The principal Powers Engineering subcontractor on this project is a Mexican firm located in Hermosillo, Sonora.

VOC Measurement Program – Mexico. Performed a comprehensive volatile organic compound (VOC) measurements program at a health products fabrication plant in Mexicali, Mexico. An FID and PID were used to quantify VOCs from five processes at the facility. Occupational exposures were also measured. Worker exposure levels were above allowable levels at several points in the main assembly area.

Fluent in Spanish. Studied at the Universidad de Michoacán in Morelia, Mexico, 1993, and at the Colegio de España in Salamanca, Spain, 1987-88. Have lectured (in Spanish) on air monitoring and control equipment at the Instituto Tecnológico de Tijuana. Maintain contact with Comisión Federal de Electricidad engineers responsible for operation of wind and geothermal power plants in Mexico, and am comfortable operating in the Mexican business environment.

PUBLICATIONS

Bill Powers, "*More Distributed Solar Means Fewer New Combustion Turbines*," Natural Gas & Electricity Journal, Vol. 29, Number 2, September 2012, pp. 17-20.

Bill Powers, "*Federal Government Betting on Wrong Solar Horse*," Natural Gas & Electricity Journal, Vol. 27, Number 5, December 2010,

Bill Powers, "*Today's California Renewable Energy Strategy—Maximize Complexity and Expense*," Natural Gas & Electricity Journal, Vol. 27, Number 2, September 2010, pp. 19-26.

Bill Powers, "*Environmental Problem Solving Itself Rapidly Through Lower Gas Costs*," Natural Gas & Electricity Journal, Vol. 26, Number 4, November 2009, pp. 9-14.

Bill Powers, "*PV Pulling Ahead, but Why Pay Transmission Costs?*" Natural Gas & Electricity Journal, Vol. 26, Number 3, October 2009, pp. 19-22.

Bill Powers, "*Unused Turbines, Ample Gas Supply, and PV to Solve RPS Issues*," Natural Gas & Electricity Journal, Vol. 26, Number 2, September 2009, pp. 1-7.

Bill Powers, "*CEC Cancels Gas-Fed Peaker, Suggesting Rooftop Photovoltaic Equally Cost-Effective*," Natural Gas & Electricity Journal, Vol. 26, Number 1, August 2009, pp. 8-13.

Bill Powers, "*San Diego Smart Energy 2020 – The 21st Century Alternative*," San Diego, October 2007.

Bill Powers, "*Energy, the Environment, and the California – Baja California Border Region*," Electricity Journal, Vol. 18, Issue 6, July 2005, pp. 77-84.

W.E. Powers, *"Peak and Annual Average Energy Efficiency Penalty of Optimized Air-Cooled Condenser on 515 MW Fossil Fuel-Fired Utility Boiler,"* presented at California Energy Commission/Electric Power Research Institute Advanced Cooling Technologies Symposium, Sacramento, California, June 2005.

W.E. Powers, R. Wydrum, P. Morris, *"Design and Performance of Optimized Air-Cooled Condenser at Crockett Cogeneration Plant,"* presented at EPA Symposium on Technologies for Protecting Aquatic Organisms from Cooling Water Intake Structures, Washington, DC, May 2003.

P. Pai, D. Niemi, W.E. Powers, *"A North American Anthropogenic Inventory of Mercury Emissions,"* presented at Air & Waste Management Association Annual Conference in Salt Lake City, UT, June 2000.

P.J. Blau and W.E. Powers, *"Control of Hazardous Air Emissions from Secondary Aluminum Casting Furnace Operations Through a Combination of: Upstream Pollution Prevention Measures, Process Modifications and End-of-Pipe Controls,"* presented at 1997 AWMA/EPA Emerging Solutions to VOC & Air Toxics Control Conference, San Diego, CA, February 1997.

W.E. Powers, et. al., *"Hazardous Air Pollutant Emission Inventory for Stationary Sources in Nogales, Sonora, Mexico ,"* presented at 1995 AWMA/EPA Emissions Inventory Specialty Conference, RTP, NC, October 1995.

W.E. Powers, *"Develop of a Parametric Emissions Monitoring System to Predict NO_x Emissions from Industrial Gas Turbines,"* presented at 1995 AWMA Golden West Chapter Air Pollution Control Specialty Conference, Ventura, California, March 1995.

W. E. Powers, et. al., *"Retrofit Control Options for Particulate Emissions from Magnesium Sulfite Recovery Boilers,"* presented at 1992 TAPPI Envr. Conference, April 1992. Published in *TAPPI Journal*, July 1992.

S. S. Parmar, M. Short, W. E. Powers, *"Determination of Total Gaseous Hydrocarbon Emissions from an Aluminum Rolling Mill Using Methods 25, 25A, and an Oxidation Technique,"* presented at U.S. EPA Measurement of Toxic and Related Air Pollutants Conference, May 1992.

N. Meeks, W. E. Powers, *"Air Toxics Emissions from Gas-Fired Internal Combustion Engines,"* presented at AIChE Summer Meeting, August 1990.

W. E. Powers, *"Air Pollution Control of Plating Shop Processes,"* presented at 7th AES/EPA Conference on Pollution Control in the Electroplating Industry, January 1986. Published in *Plating and Surface Finishing* magazine, July 1986.

H. M. Davenport, W. E. Powers, *"Affect of Low Cost Modifications on the Performance of an Undersized Electrostatic Precipitator,"* presented at 79th Air Pollution Control Association Conference, June 1986.

AWARDS

Engineer of the Year, 1991 – ENSR Consulting and Engineering, Camarillo
Engineer of the Year, 1986 – Naval Energy and Environmental Support Activity, Port Hueneme
Productivity Excellence Award, 1985 – U. S. Department of Defense

PATENTS

Sedimentation Chamber for Sizing Acid Mist, Navy Case Number 70094

Attachment B

DECLARATION OF BILL POWERS, P.E.

I, Bill Powers, P.E., declare as follows:

1. I am the principal of Powers Engineering, an engineering firm that consults on issues related to the operation of, and control of pollution from, power plants, including coal-fired power plants. My office is located in San Diego, California. My professional and educational experience is summarized in the curriculum vitae attached to this declaration (Attachment A).

2. I received a Bachelor of Science degree from Duke University in Mechanical Engineering and a Master of Public Health degree in Environmental Sciences from the University of North Carolina. I am a registered engineer in the state of California.

3. I have been an independent engineering consultant with a focus on power systems since 1994. In prior employment, I received "Engineer of the Year" awards from ENSR Consulting and Engineering in 1991 (before ENSR merged with AECOM) and from the Naval Energy and Environmental Support Activity ("NEESA") office within the U.S. Navy in 1986 (before NEESA was subsumed by the Naval Facilities Engineering Service Center). I also received a "Productivity Award of Excellence" from the U.S. Department of Defense in 1985. I worked extensively on Navy and Marine Corps shore installation of coal-fired power plants in the 1980s as a Navy civilian engineer.

4. I have over 40 years of experience in the fields of power plant operations and environmental engineering. My technical specialties include, among others: combustion equipment permitting, testing, and monitoring; air emission control assessments; air pollution control equipment retrofit design/performance; and power plant cooling system conversion.

5. I have served as an engineering expert for a wide array of clients, including private companies, non-profits, and government entities, including the cities of Carlsbad, California and Houston and Dallas, Texas. In this role, I have provided expert testimony, conducted feasibility studies, and consulted on power plant engineering issues in a number of states, including Arkansas, California, Connecticut, Florida, Georgia, Kentucky, Maryland, Missouri, Nevada, North Carolina, New York, and Tennessee.

6. I have extensive experience with coal-fired power plants. For example, in 2022 I provided expert testimony before the North Carolina Public Utility Commission regarding Duke Energy's proposed plan to maintain coal-fired units in its electric supply portfolio—a proposal that was justified in part on the company's belief that those units were necessary to meet winter peak demand. Throughout my career, I have consulted on the operation of, and control of pollution from, coal-fired power plants. Examples include serving as the lead engineer on a system and performance audit of continuous emissions monitoring systems at a coal-fired power plant in Nevada, and on a project to assess and address the root causes of opacity exceedances at Ameren Missouri's Labadie, Meramec, and Rush Island coal-fired power plants. I have also frequently provided expert testimony on coal-fired power plants. For example, I testified on air pollution controls at a coal-fired power plant in Massachusetts, and on the correlation between a Georgia coal-fired power plant's particulate matter emissions and opacity excursions, among other issues. I also served as a testifying expert on an evaluation of the air emissions limits and control technologies for a proposed coal-fired power plant in Arkansas.

7. I am very familiar with "peaking" units that are intended to ramp up and provide electricity during times of peak demand, such as during hot summer months. For example, in 2001, I prepared all aspects of the air permit applications for five 50 MW simple-cycle gas

turbine installations in response to an emergency request by the California state government for additional peaking power.

8. I am familiar with the U.S. Department of Energy's ("DOE") May 23, 2025 order regarding Consumers Energy Company's ("CECo") J.H. Campbell coal-fired power plant (Order No. 202-25-3) ("Order").

9. The J.H. Campbell coal-fired power plant ("Campbell") consists of three coal-fired generating units. The in-service dates for Units 1, 2, and 3 are 1962, 1967, and 1980 respectively.[1] The nameplate capacity for Unit 1 is 265.2 MW; for Unit 2 is 378.8 MW; and for Unit 3 is 916.8 MW.[2] Under CECo's 2021 integrated resource plan ("IRP"), which was approved with modifications by the Michigan Public Service Commission ("Michigan PSC") in 2022, the Campbell units were scheduled to retire on or before May 31, 2025.

10. I was asked by Earthjustice to develop an opinion on: (A) the extent to which Campbell can operate reliably after May 31, 2025; (B) whether Campbell can operate effectively as a peaking unit; and (C) easily attainable steps DOE can require to ensure Campbell's operations are consistent with environmental requirements and minimize adverse environmental impacts. A list of materials I reviewed in developing my opinion is attached (Attachment B).

11. While there may be alternatives to Campbell available to DOE to address the circumstances DOE describes in the Order, I do not opine on these alternatives. I also do not opine on the claimed energy emergency described in the Order.

[1] Michigan PSC Case No. U-21585, Direct Testimony of Richard T. Blumenstock on Behalf of CECo, p. 7, Tbl. 1 (May 2024).
[2] EIA, Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M as a supplement to Form EIA-860) (Apr. 2025), https://www.eia.gov/electricity/data/eia860m/ (showing nameplate capacity).

A. The extent to which Campbell can operate reliably beginning June 1, 2025

12. In my professional opinion, it is unlikely that Campbell can be depended upon to operate reliably in its current state as of June 2025.[3] This is especially true if the plant is required to run for extended periods of time; is required to stop and start numerous times; or attempts to start up at an accelerated rate in response to extreme demand conditions.

13. Even before the scheduled retirement date of May 31, 2025, Campbell suffered from poor reliability. Nationally, the average coal unit forced outage rate in 2023 was 12.0 percent.[4] In contrast, Campbell Units 1-3 had forced outage rates in 2024 of 14.84 percent, 48.07 percent, and 19.25 percent, respectively[5]—well above the average coal unit forced outage rate. The forced outage rates in 2023 were similarly high: Units 1-3 had forced outage rates of 18.66 percent, 57.32 percent, and 22.41 percent, respectively.[6]

14. "Availability" is a measure of the percent of time a unit is not in planned or forced outage and is available to generate electricity. Campbell has lower availability than coal units of comparable size. When CECo compared the availability of the Campbell units in 2019-2023 to similarly sized and fueled generating units, the company found that "[t]he availability of Campbell Units 1, 2, and 3 were all below the five-year comparisons."[7]

15. The nature of the Unit 1-3 outages in 2023 and 2024 reflects the impact of worn and difficult-to-repair or replace coal unit components on operational reliability. Outages tended to be long and recurrent. Tables 1 and 2 document the longest Unit 1-3 outages by description and duration in 2024 and 2023, respectively. The long outages on Units 1 and 2, and the types of

[3] CECo filed testimony regarding Campbell on June 2, 2025, in its most recent rate case before the Michigan PSC.
[4] NERC, *2024 State of Reliability*, p. 59 (June 2024).
[5] Michigan PSC Case No. U-21424, Direct Testimony of Nathan J. Hoffman on Behalf of CECo, Ex. A-15 (Mar. 2025).
[6] Michigan PSC Case No. U-21258, Direct Testimony of Nathan J. Hoffman on Behalf of CECo, Ex. A-14 (Mar. 2024).
[7] U-21424, Hoffman Direct Testimony, p. 22 & Ex. A-16.

failures, are the predictable result of old equipment, no capital investment, and minimal maintenance.

Table 1. Longest 2024 Outages by Type, Units 1-3 - Description and Duration[8]

Unit	Outage description	Total duration (hours)
1	• degraded governing valve (3 outages) • worn leaking superheater tube (1 outage)	911 491
2	• obsolete boiler feedwater pump failure (1 outage) • degraded valve(s) malfunction (3 outages) • worn equipment leaks, various (4 outages)	1,417 1,723 854
3	• worn/failed turbine turning gear[9] (1 outage) • worn tube leak (1 outage)	1,104 356

Table 2. Longest 2023 Outages by Type, Units 1-3 - Description and Duration[10]

Unit	Outage description	Total duration (hours)
1	• worn leaking valve and superheater tube (2 outages)	661
2	• obsolete boiler feedwater pump failure (4 outages) • worn equipment leaks (3 outages)	3,445 571
3	• worn leaking boiler/superheater tubes (3 outages) • worn/vibrating turbine bearings (1 outage)	1,857 426

16. In my professional opinion, Campbell will continue to degrade in 2025 due to the continued lack of capital investment and minimal major maintenance spending.

17. CECo dramatically reduced capital and major maintenance spending on Units 1-3 following the IRP that established a May 2025 retirement date. CECo reduced its capital spending on the units in the 2022-2025 period by approximately 91 percent compared to the amount the company projected to spend in the same period if Units 1-2 operated until 2031 and Unit 3 operated until 2039 (the retirement dates CECo originally proposed in its IRP). Likewise, CECo reduced its major maintenance spending on the units in the 2022-2025 period by 62-78

[8] U-21424, Hoffman Direct Testimony, Ex. A-11.
[9] *Ibid.*, Ex. A-13. The stated scope of the turbine turning gear repair was to "[f]abricate replacement planetary gears and drive shaft to allow for unit operation until the planned retirement in 2025."
[10] U-21258, Hoffman Direct Testimony, Ex. A-10.

percent (approximately 72% total across all three units). The reductions in capital and major maintenance spending are summarized in Table 3.[11]

Table 3. Reductions in CECo Capital and Major Maintenance Spending on Campbell Units 1-3, 2022-2025

Capital spending	Pre-IRP projected spend 2022-25 ($MM)	Post-IRP actual/projected spend 2022-25 ($MM)	% reduction
Units 1&2	60.6	4.1	93
Unit 3	85.5	8.4	90
Major maintenance spending			
Units 1&2	14.4	5.5	62
Unit 3	23.5	5.1	78

18. Some of the capital and major maintenance projects that CECo cancelled in 2022-2025 were reliability projects, while others were air emission control system projects. Regarding the reliability projects that CECo originally planned to carry out (before deciding to retire Units 1-3 in May 2025), CECo likely believed they were necessary to maintain adequate unit reliability and that failure to carry out the projects could compromise that reliability. But CECo then determined that those projects were unnecessary with the May 2025 retirement. Therefore, it is unlikely that Campbell can reliably dispatch given this deferred capital and major maintenance spending.

19. A detailed listing of the 2022-2025 capital projects that CECo projected carrying out before deciding to retire the units in May 2025 is shown in the left-hand column of Tables 4a (Units 1 and 2) and 4b (Unit 3).[12] As can be seen from the middle column in these tables,[13] CECo did not carry out most of those projects.

[11] Table 3 summarizes the information presented in Tables 4a, 4b, 5a, and 5b, which are based on CECo filings with the Michigan PSC.
[12] Information in the left-hand column is from witness Kapala's testimony in CECo's 2021 IRP case. *See* Michigan PSC Case No. U-21090, Revised Direct Testimony of Norman J. Kapala, pp. 13-18 (Oct. 2021).
[13] Information in the middle column is from witness Blumenstock's testimony in CECo's 2023-2025 rate cases. *See* Ex. A-12 to the Direct Testimony of Richard T. Blumenstock in Michigan PSC Case Nos. U-21389 (May 2023), U-21585 (May 2024), and U-21870 (June 2025).

20. Table 4a compares (i) the capital projects CECo proposed carrying out for Units 1 and 2 before deciding to retire those units in May 2025 with (ii) those projects CECo has actually carried out, or plans to carry out, after making that retirement decision. Capital spending dropped by two-thirds on Units 1 and 2 in 2022, from the proposed $12.6 million to $4.1 million. No capital spending occurred in 2023-2024, and no capital spending has yet occurred or is expected to occur in 2025 as of CECo's June 2025 rate case filing. Cancelled capital projects with a direct impact on unit reliability include, among others, partial replacement of the Unit 1 superheat outlet pendant and replacement of the Unit 2 burner assemblies and horizontal reheat system.

Table 4a. Units 1&2 Capital Spend: CECo pre-IRP projection vs. post-IRP actuals/projections

Pre-IRP projection	Post-IRP actuals/projections	Difference
2022 projected spend (in 2021): $12,556,500 $7,300,000 at Campbell Unit 1, including: • PJFF Bag Replacement ($1,578,000) • Superheat Outlet Pendant – partial replacement ($3,490,000) • Five additional projects totaling $2,232,000 $5,256,500 at Campbell Unit 2, including: • Catalyst Management ($1,120,000) • Replace Burner Assemblies ($1,350,000) • Six additional projects totaling $2,786,500	**2022 actual expenditure: $4,067,000** The 2022 actual capital expenditure primarily consisted of two projects, both on Unit 1: air preheater baskets and seals ($1,819,000), and pulse jet fabric filter bags ($1,040,000).	**$8,489,500**
2023 projected spend (in 2021): $16,686,700 $7,214,680 at Campbell Unit 1, including: • PJFF Filter Bag Replacement ($1,514,100) • Replace Air Preheater Baskets and Seals ($1,113,400) • Distributed Control System and Simulator Upgrade ($1,500,000) • Ashpit Rebuild ($1,000,000) • Twelve additional projects totaling $2,087,180 $9,472,020 at Campbell Unit 2, including: • Horizontal Reheat Replacement ($5,053,000) • SCR Reactor Catalyst Replacement ($2,000,000) • Nine additional projects totaling $2,419,020	**2023 actual expenditure: $0** The precise value reported in CECo's filing is negative (-$1,479,000). This is likely due to accounting treatment. For purposes of this analysis, I treat negative investment as $0.	**$16,686,700**
2024 projected spend (in 2021): $21,005,000 $9,753,000 at Campbell Unit 1, including: • Replace Burners Corner 1-8 ($2,700,000) • Replace Air Preheater Baskets and Seals ($1,137,100) • Boiler Component Replacement ($3,000,000) • Balance of Plant Equipment Replacement ($1,500,000) • Six additional projects totaling $1,415,900 $11,252,000 at Campbell Unit 2, including: • Horizontal Reheat Replacement ($7,952,000) • Distributed Control System and Simulator Upgrade ($1,500,000) • Four additional projects totaling $1,800,000	**2024 actual expenditure: $0** The precise value reported in CECo's filing is negative (-$1,510,000). This is likely due to accounting treatment. For purposes of this analysis, I treat negative investment as $0, which is consistent with 2024 testimony from CECo witness Blumenstock stating that the company did not plan to invest any capital in the Campbell units in 2024.[14]	**$21,005,000**
2025 projected spend (in 2021): $10,350,000 $2,550,000 at Campbell Unit 1, including four projects that do not exceed $669,000 individually $7,800,000 at Campbell Unit 2, including: • Replace turbine right side Reheat Stop Valve body ($1,850,000) • Boiler Component Replacement ($3,000,000) • Five additional projects totaling $2,950,000	**2025 projected expenditure: $0** CECo projected no capital expenditures at Unit 1 or Unit 2 in 2025.	**$10,350,000**
	TOTAL	**$56,531,200**

[14] *See* U-21585, Blumenstock Direct Testimony, p. 62.

21. Table 4b compares the capital projects CECo proposed carrying out for Unit 3 before deciding to retire that unit in May 2025 with those projects CECo has actually carried out, or plans to carry out, after making that retirement decision. Capital spending dropped by more than half on Unit 3 in 2022, from a proposed $17.1 million to $7.9 million, and dropped almost entirely in 2023, from a proposed $20.5 million to less than $0.5 million. No capital spending occurred in 2024, and no capital spending has yet occurred or is expected to occur in 2025 as of CECo's June 2025 rate case filing. Cancelled Unit 3 capital projects with a direct impact on unit reliability include, among others, complete coal mill overhauls, boiler wall panel replacements, and fuel handling repairs.

Table 4b. Unit 3 Capital Spend: CECo pre-IRP projection vs. post-IRP actuals/projections

Pre-IRP projection	Post-IRP actuals/projections	Difference
2022 projected spend (in 2021): $17,125,333 • PJFF Bag & Cleaning Air Manifold Replacement ($3,994,601) • SCR Reactor Catalyst Management ($1,866,200) • Complete Mill Overhauls ($1,264,800) • Replace CO-O2 Monitors ($967,400) • Design and Install New Large Particle Ash Screen ($1,485,100) • Fuel Handling & Infrastructure Repairs ($1,500,000) • Sixteen additional projects totaling $6,047,032	**2022 actual expenditure: $7,935,000** The 2022 actual capital expenditure included three projects: air compressor replacement ($1,207,000); selective catalytic reduction catalyst management ($1,196,000); and diesel generator controls ($1,172,000). The actual expenditure represented about 46 percent of the pre-IRP projection.	**$9,190,333**
2023 projected spend (in 2021): $20,478,187 • PJFF Bag & Cleaning Air Manifold Replacement ($3,263,331) • Complete Mill Overhauls ($1,295,300) • Design and Install New Large Particle Ash Screen ($1,008,700) • Secondary Air Heater basket & seal replacement ($2,425,000) • High Pressure Feedwater Heater 8A replacement ($5,039,800) • Fuel Handling & Infrastructure Repairs ($1,500,000) • Seventeen additional projects totaling $6,954,257	**2023 actual expenditure: $456,000** The actual capital expenditure represented about 2 percent of the pre-IRP projection.	**$20,022,187**
2024 projected spend (in 2021): $33,395,569 • SCR Reactor Catalyst Management ($1,959,510) • Turbine Drain Modifications ($2,535,000) • Superheat Terminal Drain Replacement ($3,023,100) • Replace Boiler Sidewall Panels ($2,425,000) • Replace Boiler Front And Rear Wall Panels ($2,482,900) • Secondary Air Heater basket & seal replacement ($1,562,000) • Fuel Handling & Infrastructure Repairs ($1,500,000) • Cell Construction and Permitting ($5,482,830) • and twenty-one additional projects totaling $12,425,229	**2024 actual expenditure: $0** The precise value reported in Consumers' filing is negative (-$1,264,000). This is likely due to accounting treatment. For purposes of this analysis, I treat negative investment as $0, which is consistent with 2024 testimony from CECo witness Blumenstock stating that the company did not plan to invest any capital in the Campbell units in 2024.	**$33,395,569**
2025 projected spend (in 2021): $14,512,045 • GSU Replacement ($6,485,045) • SCR Reactor Catalyst Management ($3,000,000) • AQCS Equipment repair/replacement ($1,000,000) • Cell Construction and Permitting ($2,000,000) • and four additional projects totaling $2,027,000	**2025 projected expenditure: $0** CECo projected no Unit 3 capital budget in 2025.	**$14,512,045**
	TOTAL	**$77,120,134**

22. A detailed listing of the 2022-2025 major maintenance projects that CECo projected carrying out before deciding in 2022 to retire the units in May 2025 is shown in the left-hand column of Tables 5a (Units 1 and 2) and 5b (Unit 3).[15] As can be seen from the middle column in these tables,[16] CECo did not carry out most of those projects.

23. Table 5a compares the major maintenance projects CECo proposed carrying out for Units 1 and 2 before deciding to retire those units in May 2025 with those projects CECo has actually carried out, or plans to carry out, after making that retirement decision. Major maintenance spending declined by a total of 62 percent across 2022-2025, from a proposed total of $14.4 million to $5.5 million. CECo does not specify the nature of most of its major maintenance projects in its rate case filings. However, one cancelled major maintenance project with a direct impact on unit reliability is the Unit 2 turbine valve inspection project.

[15] Information in the left-hand column is from witness Kapala's testimony in CECo's 2021 IRP case. *See* Michigan PSC Case No. U-21090, Revised Direct Testimony of Norman J. Kapala, pp. 28-30 (Oct. 2021).
[16] Information in the middle column is from witness Blumenstock's testimony in CECo's 2023-2025 rate cases. *See* Ex. A-41 to the Direct Testimony of Richard T. Blumenstock in Michigan PSC Case No. U-21389 (May 2023) and Ex. A-43 to witness Blumenstock's testimony in Case Nos. U-21585 (May 2024), and U-21870 (June 2025).

Table 5a. Units 1&2 Major Maintenance Spend: CECo pre-IRP projection vs. post-IRP actuals/projections

Pre-IRP projection	Post-IRP actuals/projections	Difference
2022 projected spend (in 2021): $3,537,000 • Campbell 1 and 2 Periodic Outage Maintenance ($1,248,000) • Thirteen additional projects totaling $2,289,000	**2022 actual expenditure: $3,307,000** The 2022 actual maintenance expenditure was slightly less than the Unit 1&2 maintenance budget projected by CECo in 2021.	**$230,000**
2023 projected spend (in 2021): $2,905,000 • Covering 10 projects	**2023 actual expenditure: $1,054,000** The 2023 actual maintenance expenditure was approximately one-third the Unit 1&2 maintenance budget proposed for 2023 by CECo in 2021.	**$1,851,000**
2024 projected spend (in 2021): $3,405,167 • Covering 12 projects	**2024 actual expenditure: $903,000** The 2024 actual maintenance expenditure was approximately 27 percent of the Unit 1&2 maintenance budget proposed for 2024 by CECo in 2021.	**$2,502,167**
2025 projected spend (in 2021): $4,569,000 • Campbell 2 Turbine Valve Inspection ($1,300,000) • Seven additional projects totaling $3,269,000	**2025 projected expenditure:**[17] **$268,000** The 2025 projected maintenance expenditure was approximately 6 percent of the Unit 1&2 maintenance budget proposed for 2025 by CECo in 2021.	**$4,301,000**
	TOTAL	**$8,884,167**

[17] *See* U-21585, Ex. A-43 to Blumenstock Direct Testimony. This exhibit shows the "Projected Test Year 12 Months Ending 02/28/26." This 12-month cost projection covers most of the 5-month 2025 operational period (1/1/25 – 5/31/25) for Campbell Units 1&2 as well as the additional months those units would not be operational. From the information I reviewed, this is the best source of information regarding CECo's actual and projected 2025 major maintenance spending.

24. Table 5b compares the major maintenance projects CECo proposed carrying out for Unit 3 before deciding to retire that unit in May 2025 with those projects CECo has actually carried out, or plans to carry out, after making that retirement decision. Major maintenance spending declined by a total of 78 percent across 2022-2025, from a proposed total of $23.5 million to $5.1 million. CECo does not specify most of its major maintenance projects in its rate case filings. However, as discussed in more detail below, one cancelled major maintenance project with a direct impact on unit reliability is the $7.9 million Unit 3 turbine overhaul project. The project was originally scheduled to take place in 2024. The turbine failed in April 2024 resulting in a 46-day forced outage.[18]

[18] *See infra* Tbl. 1.

Table 5b. Unit 3 Major Maintenance Spend: CECo pre-IRP projection vs. post-IRP actuals/projections

Pre-IRP projection	Post-IRP actuals/projections	Difference
2022 projected spend (in 2021): $4,208,040 • Boiler Feed Pump Turbine Inspection ($1,680,000) • Fourteen additional projects totaling $2,528,040	**2022 actual expenditure: $3,196,000** The 2022 actual maintenance expenditure was sufficient to do about 75 percent of the Unit 3 maintenance projects budgeted for 2022 by CECo in 2021.	**$1,012,040**
2023 projected spend (in 2021): $2,523,970 • Covering 12 projects	**2023 actual expenditure: $995,000** The actual expenditure represented about 40 percent of the pre-IRP projection.	**$1,528,970**
2024 projected spend (in 2021): $12,954,250 • Campbell 3 Turbine Overhaul ($7,931,350) • Campbell 3 Boiler Chemical Cleaning ($1,429,000) • Campbell 3 Base Outage Boiler and Critical Maintenance ($1,000,000) • Campbell 3 Periodic Outage Maintenance ($933,100) • Eight additional projects totaling $1,660,800	**2024 actual expenditure: $591,000** The 2024 projected actual maintenance expenditure was sufficient to do about 5 percent of the Unit 3 maintenance projects budgeted for 2024 by CECo in 2021. The highest cost proposed 2024 project, the Campbell 3 Turbine Overhaul ($7,931,350), was not carried out. The turbine failed in April 2024 resulting in a 46-day forced outage.	**$12,363,250**
2025 projected spend (in 2021): $3,810,600 • Campbell 3 Turbine Valve Inspection ($1,200,000) • Campbell 3 Base Outage Boiler and Critical Maintenance ($1,100,000) • Six additional projects totaling $1,410,600	**2025 projected expenditure:**[19] **$277,000** The actual expenditure represented about 7 percent of the pre-IRP projection.	**$3,533,600**
	TOTAL	**$18,437,860**

[19] *See* U-21585, Ex. A-43 to Blumenstock Direct Testimony. This exhibit shows the "Projected Test Year 12 Months Ending 02/28/26." This 12-month cost projection covers most of the 5-month 2025 operational period (1/1/25 – 5/31/25) for Campbell Unit 3 as well as the additional months that unit would not be operational. From the information I reviewed, this is the best source of information regarding CECo's actual and projected 2025 major maintenance spending.

25. It is unlikely that Campbell can reliably dispatch given this deferred capital and major maintenance spending.

26. Moreover, Campbell Units 1 and 2 were built in the 1960s. Units 1 and 2 are beyond both a typical coal unit economic design life of 30-40 years and a typical operational lifetime of 40-50 years.[20,21]

27. Replacement parts are not readily available or do not exist for Units 1 and 2, as described by CECo witness Hoffman: "Some of these units were built in the 1960s, and given the ages and designs of the systems, replacement parts are not always readily available. In some instances, replacement parts do not exist at all. The start-up boiler feed pump ("SUBFP") at Campbell Unit 2 is one of those systems. Keeping spare parts on hand is neither cost effective nor practical since replacements do not exist."[22]

28. CECo witness Blumenstock states that CECo discontinued capital investment in Units 1-3 in 2023 and is only doing sufficient maintenance to keep Units 1-3 operable through May 2025: "The Company does not plan to invest any capital in the Campbell units during the bridge period [2024 and early 2025] or test year . . . [T]he Company has projected modest amounts of major maintenance to ensure that these units are able to operate through their retirement date of May 31, 2025."[23] Witness Blumenstock also indicates that Unit 1 would be retired early, on April 1, 2025.[24]

29. In my professional opinion, witness Blumenstock is describing CECo's transition from a preventative capital investment and maintenance structure, intended to maintain the

[20] M. Hafner, G. Luciani, *The Palgrave Handbook of International Energy Economics*, p. 127 (2022).
[21] International Energy Agency, *The role of CCUS in low-carbon power systems*, p. 18 (2020).
[22] U-21424, Hoffman Direct Testimony, p.6.
[23] U-21585, Blumenstock Direct Testimony, p. 62.
[24] *Ibid*., p. 20.

Campbell units' long-term reliability, to a reactive, "fix it if breaks" approach to operating Units 1-3. CECo's objective shifted from maintaining long-term reliability to keeping the units operating—to the extent possible with little or no spending—*up until* May 31, 2025 *and no longer.* CECo's objective was *not* to achieve the high level of Unit 1-3 reliability that would be necessary for the units to ramp up and work reliably under emergency demand conditions.

30. A case in point is the cancelled $7.9 million Unit 3 turbine overhaul project that was originally scheduled for 2024.[25] In late April 2024, the Unit 3 turbine suffered a turning gear failure that resulted in a 1,104-hour (46 day) forced outage.[26] The turbine turning gear was repaired to achieve the limited objective of allowing Unit 3 to continue to operate until the planned retirement in (May) 2025.[27] It is reasonable to assume that the turning gear failure would not have occurred if the Unit 3 turbine had already been overhauled. This failure incident calls into question how many other Unit 3 components are vulnerable to near-term failure due to lack of investment and preventative maintenance by CECo. Given the limited maintenance, it would be unreasonable for DOE to assume that Unit 3 can run much longer without CECo doing a substantial amount of deferred maintenance.

31. While it is not possible based on publicly available information to put an exact price tag on the cost of ensuring that Campbell could reliably operate at full capacity, CECo cancelled **approximately $161 million** in planned capital and major maintenance projects at Campbell over the past four years ($133.6 million in capital projects; $27.3 million in major maintenance projects). It is reasonable to assume that much of this investment was necessary to ensure continued, nominally reliable operation of Campbell. It is also reasonable to assume that

[25] U-21090, Kapala Revised Direct Testimony, p. 29.
[26] U-21424, Ex. A-11 to Hoffman Direct Testimony.
[27] *Ibid*., Ex. A-13.

some of this investment was necessary to ensure compliance with environmental requirements, as discussed more below. Those capital and major maintenance investments are what *CECo determined* in 2021 that it would need to spend on a year-to-year basis to operate the Campbell units reliably and in conformance with environmental requirements in 2022-2025, if these units were to continue to operate past May 2025 (i.e. until 2031 for Units 1 and 2 and until 2039 for Unit 3).

B. Whether Campbell can operate effectively as a peaking unit

32. In my opinion, Campbell cannot operate effectively as a peaking unit that would be dispatched with only a few hours of notice to meet an extreme demand condition.

33. Coal units generally, and Campbell's three units specifically, cannot serve as peaking units that respond to extreme peak demand on short notice. Coal units are designed for baseload, round-the-clock operation.[28] Coal units started "cold" (room temperature) typically take approximately 12 hours to reach full load operation.[29] The ramp rate is slow to avoid excessive thermal stress on components exposed to heat. In contrast, utility-scale battery storage can dispatch from a cold start to full power in a matter of seconds.[30] Similarly, combustion gas turbines, designed for fast-response peaking duty, can go from a cold start to full power in 5 to 10 minutes.[31]

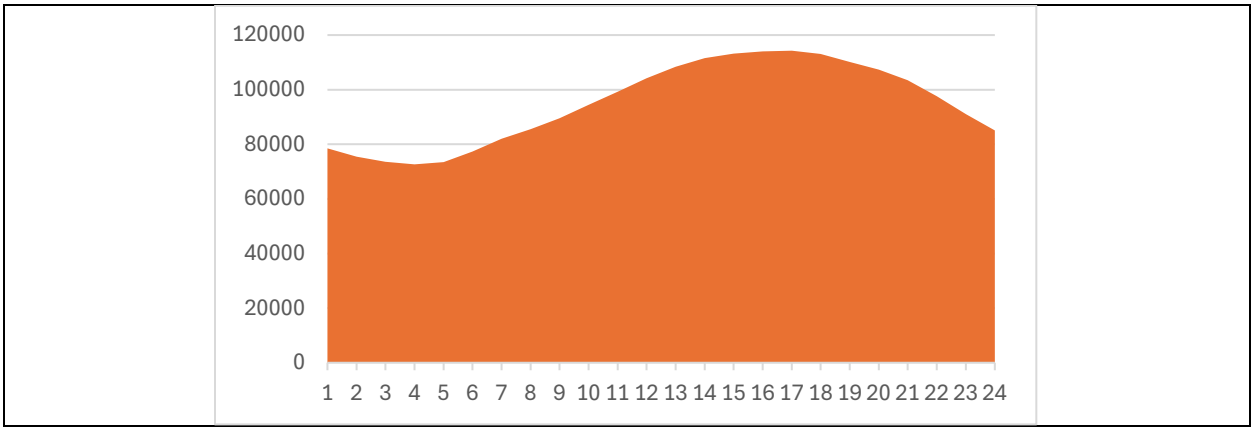
34. Coal units cannot respond to extreme demand events unless they are fully online several hours before the high demand situation occurs. In other words, coal units need

[28] U-21258, Hoffman Direct Testimony, pp. 4-5.
[29] IEA Clean Coal Centre, *Increasing the flexibility of coal-fired power plants*, p. 26 (Sept. 2014).
[30] NERC, *Energy Storage: Overview of Electrochemical Storage*, p. 1 (Feb. 2021). https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/Master_ESAT_Report.pdf ("BESS are a well suited technology to provide short-term grid contingency support (tens of seconds) . . . .").
[31] General Electric, *Get to know the LM6000* (webpage) (2025), https://www.gevernova.com/gas-power/products/gas-turbines/lm6000. ("With around five minutes to ramp up from start-up to full power . . . .").

substantial lead time to be fully operational at or before an extreme peak demand is reached. They cannot be dispatched from an offline "cold" status to address extreme emergency demand if an emergency is declared only a few hours before the demand must be met.

35. Grid demand often increases rapidly on peak demand days. MISO may have only a few hours of notice that an extreme peak demand day is developing. The need to bring on additional generation resources to meet an extreme peak may be uncertain until the period immediately prior to the actual peak. An example of this can be seen in Figure 1, which shows a 24-hour demand curve for the MISO control area on the high demand summer day of September 5, 2023.[32] MISO actual demand was rising as fast as 5,000 MW per hour during the day, adding the equivalent of Campbell's 1,561 MW capacity every 20 minutes to meet demand.

Figure 1. MISO 24-hour demand curve (MW), September 5, 2023



36. Bringing Campbell from a cold start condition to full output to meet extreme demand would also be expensive. According to the National Association of Regulatory Utility Commissioners, the estimated cost to "cold start" a coal-fired power plant is $417 per MW of capacity.[33] The total nameplate capacity of Campbell Units 1-3 is 1,561 MW. Therefore, the

[32] Figure 1 was developed using data from U.S. EIA, csv dataset, "MISO_load-temp_hr_2023" (accessed June 13, 2025).
[33] NARUC, *Recent Changes to U.S. Coal Plant Operations and Current Compensation Practices*, p. 16 (Jan. 2020).

estimated cost to start up Campbell from a cold start condition would be approximately $650,000. (1,561 MW × $417 per MW = $650,937).

37. Alternatively, instead of starting cold, CECo could be forced to run Campbell for hours unnecessarily solely to be prepared for a potential near-term high-peak demand. That approach would be expensive and polluting.

C. Easily attainable steps DOE can require to ensure Campbell's operations are consistent with environmental requirements and minimize adverse environmental impacts

38. In my opinion, for DOE's order to be consistent with environmental requirements, CECo must demonstrate, prior to restarting Units 1-3, that (1) the pulse jet fabric filters on Units 1-3 are in sound, leak-free condition, and (2) the SCRs on Units 2 and 3 have sufficient remaining catalyst life to adequately control NO_x emissions.

39. As noted above, some of the capital and major maintenance projects cancelled in 2022-2025 were air emission control system projects. Cancelled capital projects with a direct impact on maintaining environmental compliance included, among others, PJFF filter bag(s) replacement on Unit 1 (for particulate/opacity control); SCR reactor catalyst replacement on Unit 2 (for nitrogen oxide control); and replacement of PJFF filter bag(s), "cleaning air manifold," and SCR reactor catalyst on Unit 3.[34] These projects were planned likely because CECo believed they were necessary to maintain adequate air emission control system performance and that failure to carry out the projects could compromise that performance.

40. Table 6 shows the multiple air emission control system capital projects that were cancelled in 2022-2025. The implications of these cancelled air quality control system projects are: (1) degraded fabric filter performance on Units 1 and 3, potentially resulting in particulate

[34] *See infra* Tables 4a and 4b.

and/or opacity exceedances, and (2) degraded performance of nitrogen oxide (NO_x) control systems (SCR) on Units 2 and 3, potentially resulting in NO_x exceedances. Degraded fabric filter performance, caused by torn or improperly secured filter bags, could lead to elevated levels of opacity and particulate emissions. A degraded SCR catalyst could lead to poor NO_x conversion and elevated NO_x emissions at the stack.

Table 6. Cancelled 2022-2025 Campbell Unit 1-3 air quality control capital projects

Year	Unit	Project[35]	Budget ($)
2022	2 3	• (SCR) catalyst management • Fabric filter bag(s) & cleaning air manifold replacement	1,120,000 3,994,601
2023	1 2 3	• Fabric filter bag replacement • SCR reactor catalyst replacement • Fabric filter bag(s) & cleaning air manifold replacement	1,514,100 2,000,000 3,263,331
2025	3	• SCR reactor catalyst management • Air quality control system (AQCS) equipment repair/replacement	3,000,000 1,000,000

41. In light of these cancelled projects, DOE should require that CECo demonstrate that the Campbell Unit 1-3 pulse jet fabric filters are currently leak free prior to authorizing further operation. DOE also should require that CECo provide records demonstrating that the catalysts in the Units 2 and 3 SCRs have sufficient remaining useful life to reasonably assure compliance with NO_x limits.

42. It is my opinion that DOE should require verification of the good working order of the Unit 1-3 air emission control systems before authorizing Campbell to operate under extreme demand conditions. DOE should also require that any Campbell unit that exceeds air permit limits for opacity, NO_x, or SO_2 that occur during operation of Units 1-3, as registered on the continuous opacity, NO_x, or SO_2 monitors installed on each unit, be shut down.

[35] *See* U-21090, Kapala Revised Direct Testimony; U-21389, Blumenstock Direct Testimony, Ex. A-12 (not listed as carried-out); U-21585, Blumenstock Direct Testimony, A-12 (not listed as carried-out).

43. It is also my opinion that there are alternatives to running Campbell to meet an extreme peak demand that would produce far less environmental harm.

44. Any air emissions that result from running Campbell would not occur if the plant is retired. Additionally, according to its NPDES wastewater discharge permit, Campbell is cooled with ~1 billion gallons per day of Lake Michigan water in a once-through cooling configuration (NPDES permit). Therefore, the plant will use up to 1 billion gallons per day if called to operate. That is a potentially significant impact on Lake Michigan marine fauna that does not occur if Campbell is retired. Finally, any coal burned will produce coal ash that will have to be stored/disposed of onsite. That is another impact that would not occur if Campbell is retired.

45. In my opinion, a coal unit would be the last alternative to consider for a peaking power application due to its slow ramp time and high environmental impact.

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 15th day of June 2025, in San Diego, California.

Bill Powers, P.E.

Bill Powers, P.E.
Powers Engineering
4452 Park Blvd., Suite 209
San Diego, CA 92116

Attachment C

MICHIGAN DEPARTMENT OF ENVIRONMENT, GREAT LAKES, AND ENERGY
AIR QUALITY DIVISION

EFFECTIVE DATE: February 4, 2020
REVISION DATES: September 3, 2020, July 2, 2021

ISSUED TO

Consumers Energy, J.H. Campbell Generating Complex

State Registration Number (SRN): B2835

LOCATED AT

17000 Croswell, West Olive, Ottawa County, Michigan 49460

RENEWABLE OPERATING PERMIT

Permit Number: MI-ROP-B2835-2020b

Expiration Date: February 4, 2025

Administratively Complete ROP Renewal Application
Due Between August 4, 2023 and August 4, 2024

This Renewable Operating Permit (ROP) is issued in accordance with and subject to Section 5506(3) of Part 55, Air Pollution Control, of the Natural Resources and Environmental Protection Act, 1994 PA 451, as amended (Act 451). Pursuant to Rule 210(1) of the administrative rules promulgated under Act 451, this ROP constitutes the permittee's authority to operate the stationary source identified above in accordance with the general conditions, special conditions and attachments contained herein. Operation of the stationary source and all emission units listed in the permit are subject to all applicable future or amended rules and regulations pursuant to Act 451 and the federal Clean Air Act.

SOURCE-WIDE PERMIT TO INSTALL

Permit Number: MI-PTI-B2835-2020b

This Permit to Install (PTI) is issued in accordance with and subject to Section 5505(1) of Act 451. Pursuant to Rule 214a of the administrative rules promulgated under Act 451, the terms and conditions herein, identified by the underlying applicable requirement citation of Rule 201(1)(a), constitute a federally enforceable PTI. The PTl terms and conditions do not expire and remain in effect unless the criteria of Rule 201(6) are met. Operation of all emission units identified in the PTI is subject to all applicable future or amended rules and regulations pursuant to Act 451 and the federal Clean Air Act.

Michigan Department of Environment, Great Lakes, and Energy

_____

Heidi Hollenbach, Grand Rapids District Supervisor

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AUTHORITY AND ENFORCEABILITY

For the purpose of this permit, the **permittee** is defined as any person who owns or operates an emission unit at a stationary source for which this permit has been issued. The **department** is defined in Rule 104(d) as the Director of the Michigan Department of Environment, Great Lakes, and Energy (EGLE) or his or her designee.

The permittee shall comply with all specific details in the permit terms and conditions and the cited underlying applicable requirements. All terms and conditions in this ROP are both federally enforceable and state enforceable unless otherwise footnoted. Certain terms and conditions are applicable to most stationary sources for which an ROP has been issued. These general conditions are included in Part A of this ROP. Other terms and conditions may apply to a specific emission unit, several emission units which are represented as a flexible group, or the entire stationary source which is represented as a Source-Wide group. Special conditions are identified in Parts B, C, D and/or the appendices.

In accordance with Rule 213(2)(a), all underlying applicable requirements are identified for each ROP term or condition. All terms and conditions that are included in a PTI are streamlined, subsumed and/or is state-only enforceable will be noted as such.

In accordance with Section 5507 of Act 451, the permittee has included in the ROP application a compliance certification, a schedule of compliance, and a compliance plan. For applicable requirements with which the source is in compliance, the source will continue to comply with these requirements. For applicable requirements with which the source is not in compliance, the source will comply with the detailed schedule of compliance requirements that are incorporated as an appendix in this ROP. Furthermore, for any applicable requirements effective after the date of issuance of this ROP, the stationary source will meet the requirements on a timely basis, unless the underlying applicable requirement requires a more detailed schedule of compliance.

Issuance of this permit does not obviate the necessity of obtaining such permits or approvals from other units of government as required by law.

This permit does not relieve the permittee from any responsibilities or obligations imposed on the permittee, at the source under Consent Decree U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014, entered in 2014 between the USEPA and the permittee.

A. GENERAL CONDITIONS

Permit Enforceability

- All conditions in this permit are both federally enforceable and state enforceable unless otherwise noted. **(R 336.1213(5))**

- Those conditions that are hereby incorporated in a state-only enforceable Source-Wide PTI pursuant to Rule 201(2)(d) are designated by footnote one. **(R 336.1213(5)(a), R 336.1214a(5))**

- Those conditions that are hereby incorporated in a federally enforceable Source-Wide PTI pursuant to Rule 201(2)(c) are designated by footnote two. **(R 336.1213(5)(b), R 336.1214a(3))**

General Provisions

1. The permittee shall comply with all conditions of this ROP. Any ROP noncompliance constitutes a violation of Act 451, and is grounds for enforcement action, for ROP revocation or revision, or for denial of the renewal of the ROP. All terms and conditions of this ROP that are designated as federally enforceable are enforceable by the Administrator of the United States Environmental Protection Agency (USEPA) and by citizens under the provisions of the federal Clean Air Act (CAA). Any terms and conditions based on applicable requirements which are designated as "state-only" are not enforceable by the USEPA or citizens pursuant to the CAA. **(R 336.1213(1)(a))**

2. It shall not be a defense for the permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this ROP. **(R 336.1213(1)(b))**

3. This ROP may be modified, revised, or revoked for cause. The filing of a request by the permittee for a permit modification, revision, or termination, or a notification of planned changes or anticipated noncompliance does not stay any ROP term or condition. This does not supersede or affect the ability of the permittee to make changes, at the permittee's own risk, pursuant to Rule 215 and Rule 216. **(R 336.1213(1)(c))**

4. The permittee shall allow the department, or an authorized representative of the department, upon presentation of credentials and other documents as may be required by law and upon stating the authority for and purpose of the investigation, to perform any of the following activities: **(R 336.1213(1)(d))**
   a. Enter, at reasonable times, a stationary source or other premises where emissions-related activity is conducted or where records must be kept under the conditions of the ROP.
   b. Have access to and copy, at reasonable times, any records that must be kept under the conditions of the ROP.
   c. Inspect, at reasonable times, any of the following:
      i. Any stationary source.
      ii. Any emission unit.
      iii. Any equipment, including monitoring and air pollution control equipment.
      iv. Any work practices or operations regulated or required under the ROP.
   d. As authorized by Section 5526 of Act 451, sample or monitor at reasonable times substances or parameters for the purpose of assuring compliance with the ROP or applicable requirements.

5. The permittee shall furnish to the department, within a reasonable time, any information the department may request, in writing, to determine whether cause exists for modifying, revising, or revoking the ROP or to determine compliance with this ROP. Upon request, the permittee shall also furnish to the department copies of any records that are required to be kept as a term or condition of this ROP. For information which is claimed by the permittee to be confidential, consistent with the requirements of the 1976 PA 442, MCL §15.231 et seq., and known as the Freedom of Information Act, the person may also be required to furnish the records directly to the USEPA together with a claim of confidentiality. **(R 336.1213(1)(e))**

6. A challenge by any person, the Administrator of the USEPA, or the department to a particular condition or a part of this ROP shall not set aside, delay, stay, or in any way affect the applicability or enforceability of any other condition or part of this ROP. **(R 336.1213(1)(f))**

7. The permittee shall pay fees consistent with the fee schedule and requirements pursuant to Section 5522 of Act 451. **(R 336.1213(1)(g))**

8. This ROP does not convey any property rights or any exclusive privilege. **(R 336.1213(1)(h))**

Equipment & Design

9. Any collected air contaminants shall be removed as necessary to maintain the equipment at the required operating efficiency. The collection and disposal of air contaminants shall be performed in a manner so as to minimize the introduction of contaminants to the outer air. Transport of collected air contaminants in Priority I and II areas requires the use of material handling methods specified in Rule 370(2).[2] **(R 336.1370)**

10. Any air cleaning device shall be installed, maintained, and operated in a satisfactory manner and in accordance with the Michigan Air Pollution Control rules and existing law. **(R 336.1910)**

Emission Limits

11. Unless otherwise specified in this ROP, the permittee shall comply with Rule 301, which states, in part, "Except as provided in Subrules 2, 3, and 4 of this rule, a person shall not cause or permit to be discharged into the outer air from a process or process equipment a visible emission of a density greater than the most stringent of the following:"[2] **(R 336.1301(1))**
    a. A 6-minute average of 20% opacity, except for one 6-minute average per hour of not more than 27% opacity.
    b. A limit specified by an applicable federal new source performance standard.

    The grading of visible emissions shall be determined in accordance with Rule 303.

12. The permittee shall not cause or permit the emission of an air contaminant or water vapor in quantities that cause, alone or in reaction with other air contaminants, either of the following:
    a. Injurious effects to human health or safety, animal life, plant life of significant economic value, or property.[1] **(R 336.1901(a))**
    b. Unreasonable interference with the comfortable enjoyment of life and property.[1] **(R 336.1901(b))**

Testing/Sampling

13. The department may require the owner or operator of any source of an air contaminant to conduct acceptable performance tests, at the owner's or operator's expense, in accordance with Rule 1001 and Rule 1003, under any of the conditions listed in Rule 1001(1).[2] **(R 336.2001)**

14. Any required performance testing shall be conducted in accordance with Rule 1001(2), Rule 1001(3) and Rule 1003. **(R 336.2001(2), R 336.2001(3), R 336.2003(1))**

15. Any required test results shall be submitted to the Air Quality Division (AQD) in the format prescribed by the applicable reference test method within 60 days following the last date of the test. **(R 336.2001(5))**

Monitoring/Recordkeeping

16. Records of any periodic emission or parametric monitoring required in this ROP shall include the following information specified in Rule 213(3)(b)(i), where appropriate. **(R 336.1213(3)(b))**
    a. The date, location, time, and method of sampling or measurements.
    b. The dates the analyses of the samples were performed.
    c. The company or entity that performed the analyses of the samples.
    d. The analytical techniques or methods used.
    e. The results of the analyses.
    f. The related process operating conditions or parameters that existed at the time of sampling or measurement.

17. All required monitoring data, support information and all reports, including reports of all instances of deviation from permit requirements, shall be kept and furnished to the department upon request for a period of not less than 5 years from the date of the monitoring sample, measurement, report or application. Support information includes all calibration and maintenance records and all original strip-chart recordings, or other original data records, for continuous monitoring instrumentation and copies of all reports required by the ROP. **(R 336.1213(1)(e), R 336.1213(3)(b)(ii))**

Certification & Reporting

18. Except for the alternate certification schedule provided in Rule 213(3)(c)(iii)(B), any document required to be submitted to the department as a term or condition of this ROP shall contain an original certification by a Responsible Official which state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete. **(R 336.1213(3)(c))**

19. A Responsible Official shall certify to the appropriate AQD District Office and to the USEPA that the stationary source is and has been in compliance with all terms and conditions contained in the ROP except for deviations that have been or are being reported to the appropriate AQD District Office pursuant to Rule 213(3)(c). This certification shall include all the information specified in Rule 213(4)(c)(i) through (v) and shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the certification are true, accurate, and complete. The USEPA address is: USEPA, Air Compliance Data - Michigan, Air and Radiation Division, 77 West Jackson Boulevard, Chicago, Illinois 60604-3507. **(R 336.1213(4)(c))**

20. The certification of compliance shall be submitted annually for the term of this ROP as detailed in the special conditions, or more frequently if specified in an applicable requirement or in this ROP. **(R 336.1213(4)(c))**

21. The permittee shall promptly report any deviations from ROP requirements and certify the reports. The prompt reporting of deviations from ROP requirements is defined in Rule 213(3)(c)(ii) as follows, unless otherwise described in this ROP. **(R 336.1213(3)(c))**
    a. For deviations that exceed the emissions allowed under the ROP, prompt reporting means reporting consistent with the requirements of Rule 912 as detailed in Condition 25. All reports submitted pursuant to this paragraph shall be promptly certified as specified in Rule 213(3)(c)(iii).
    b. For deviations which exceed the emissions allowed under the ROP and which are not reported pursuant to Rule 912 due to the duration of the deviation, prompt reporting means the reporting of all deviations in the semiannual reports required by Rule 213(3)(c)(i). The report shall describe reasons for each deviation and the actions taken to minimize or correct each deviation.
    c. For deviations that do not exceed the emissions allowed under the ROP, prompt reporting means the reporting of all deviations in the semiannual reports required by Rule 213(3)(c)(i). The report shall describe the reasons for each deviation and the actions taken to minimize or correct each deviation.

22. For reports required pursuant to Rule 213(3)(c)(ii), prompt certification of the reports is described in Rule 213(3)(c)(iii) as either of the following: **(R 336.1213(3)(c))**
    a. Submitting a certification by a Responsible Official with each report which states that, based on information and belief formed after reasonable inquiry, the statements and information in the report are true, accurate, and complete.
    b. Submitting, within 30 days following the end of a calendar month during which one or more prompt reports of deviations from the emissions allowed under the ROP were submitted to the department pursuant to Rule 213(3)(c)(ii), a certification by a Responsible Official which states that; "based on information and belief formed after reasonable inquiry, the statements and information contained in each of the reports submitted during the previous month were true, accurate, and complete." The certification shall include a listing of the reports that are being certified. Any report submitted pursuant to Rule 213(3)(c)(ii) that will be certified on a monthly basis pursuant to this paragraph shall include a statement that certification of the report will be provided within 30 days following the end of the calendar month.

23. Semiannually for the term of the ROP as detailed in the special conditions, or more frequently if specified, the permittee shall submit certified reports of any required monitoring to the appropriate AQD District Office. All instances of deviations from ROP requirements during the reporting period shall be clearly identified in the reports. **(R 336.1213(3)(c)(i))**

24. On an annual basis, the permittee shall report the actual emissions, or the information necessary to determine the actual emissions, of each regulated air pollutant as defined in Rule 212(6) for each emission unit utilizing the emissions inventory forms provided by the department. **(R 336.1212(6))**

25. The permittee shall provide notice of an abnormal condition, start-up, shutdown, or malfunction that results in emissions of a hazardous or toxic air pollutant which continue for more than one hour in excess of any applicable standard or limitation, or emissions of any air contaminant continuing for more than two hours in excess of an applicable standard or limitation, as required in Rule 912, to the appropriate AQD District Office. The notice shall be provided not later than two business days after the start-up, shutdown, or discovery of the abnormal conditions or malfunction. Notice shall be by any reasonable means, including electronic, telephonic, or oral communication. Written reports, if required under Rule 912, must be submitted to the appropriate AQD District Supervisor within 10 days after the start-up or shutdown occurred, within 10 days after the abnormal conditions or malfunction has been corrected, or within 30 days of discovery of the abnormal conditions or malfunction, whichever is first. The written reports shall include all of the information required in Rule 912(5) and shall be certified by a Responsible Official in a manner consistent with the CAA.[2] **(R 336.1912)**

Permit Shield

26. Compliance with the conditions of the ROP shall be considered compliance with any applicable requirements as of the date of ROP issuance if either of the following provisions is satisfied. **(R 336.1213(6)(a)(i), R 336.1213(6)(a)(ii))**
    a. The applicable requirements are included and are specifically identified in the ROP.
    b. The permit includes a determination or concise summary of the determination by the department that other specifically identified requirements are not applicable to the stationary source.

    Any requirements identified in Part E of this ROP have been identified as non-applicable to this ROP and are included in the permit shield.

27. Nothing in this ROP shall alter or affect any of the following:
    a. The provisions of Section 303 of the CAA, emergency orders, including the authority of the USEPA under Section 303 of the CAA. **(R 336.1213(6)(b)(i))**
    b. The liability of the owner or operator of this source for any violation of applicable requirements prior to or at the time of this ROP issuance. **(R 336.1213(6)(b)(ii))**
    c. The applicable requirements of the acid rain program, consistent with Section 408(a) of the CAA. **(R 336.1213(6)(b)(iii))**

d. The ability of the USEPA to obtain information from a source pursuant to Section 114 of the CAA. **(R 336.1213(6)(b)(iv))**

28. The permit shield shall not apply to provisions incorporated into this ROP through procedures for any of the following:
    a. Operational flexibility changes made pursuant to Rule 215. **(R 336.1215(5))**
    b. Administrative Amendments made pursuant to Rule 216(1)(a)(i)-(iv). **(R 336.1216(1)(b)(iii))**
    c. Administrative Amendments made pursuant to Rule 216(1)(a)(v) until the amendment has been approved by the department. **(R 336.1216(1)(c)(iii))**
    d. Minor Permit Modifications made pursuant to Rule 216(2). **(R 336.1216(2)(f))**
    e. State-Only Modifications made pursuant to Rule 216(4) until the changes have been approved by the department. **(R 336.1216(4)(e))**

29. Expiration of this ROP results in the loss of the permit shield. If a timely and administratively complete application for renewal is submitted not more than 18 months, but not less than 6 months, before the expiration date of the ROP, but the department fails to take final action before the end of the ROP term, the existing ROP does not expire until the renewal is issued or denied, and the permit shield shall extend beyond the original ROP term until the department takes final action. **(R 336.1217(1)(c), R 336.1217(1)(a))**

Revisions

30. For changes to any process or process equipment covered by this ROP that do not require a revision of the ROP pursuant to Rule 216, the permittee must comply with Rule 215. **(R 336.1215, R 336.1216)**

31. A change in ownership or operational control of a stationary source covered by this ROP shall be made pursuant to Rule 216(1). **(R 336.1219(2))**

32. For revisions to this ROP, an administratively complete application shall be considered timely if it is received by the department in accordance with the time frames specified in Rule 216. **(R 336.1210(10))**

33. Pursuant to Rule 216(1)(b)(iii), Rule 216(2)(d) and Rule 216(4)(d), after a change has been made, and until the department takes final action, the permittee shall comply with both the applicable requirements governing the change and the ROP terms and conditions proposed in the application for the modification. During this time period, the permittee may choose to not comply with the existing ROP terms and conditions that the application seeks to change. However, if the permittee fails to comply with the ROP terms and conditions proposed in the application during this time period, the terms and conditions in the ROP are enforceable. **(R 336.1216(1)(c)(iii), R 336.1216(2)(d), R 336.1216(4)(d))**

Reopenings

34. A ROP shall be reopened by the department prior to the expiration date and revised by the department under any of the following circumstances:
    a. If additional requirements become applicable to this stationary source with three or more years remaining in the term of the ROP, but not if the effective date of the new applicable requirement is later than the ROP expiration date. **(R 336.1217(2)(a)(i))**
    b. If additional requirements pursuant to Title IV of the CAA become applicable to this stationary source. **(R 336.1217(2)(a)(ii))**
    c. If the department determines that the ROP contains a material mistake, information required by any applicable requirement was omitted, or inaccurate statements were made in establishing emission limits or the terms or conditions of the ROP. **(R 336.1217(2)(a)(iii))**
    d. If the department determines that the ROP must be revised to ensure compliance with the applicable requirements. **(R 336.1217(2)(a)(iv))**

Renewals

35. For renewal of this ROP, an administratively complete application shall be considered timely if it is received by the department not more than 18 months, but not less than 6 months, before the expiration date of the ROP. **(R 336.1210(9))**

Stratospheric Ozone Protection

36. If the permittee is subject to Title 40 of the Code of Federal Regulations (CFR), Part 82 and services, maintains, or repairs appliances except for motor vehicle air conditioners (MVAC), or disposes of appliances containing refrigerant, including MVAC and small appliances, or if the permittee is a refrigerant reclaimer, appliance owner or a manufacturer of appliances or recycling and recovery equipment, the permittee shall comply with all applicable standards for recycling and emissions reduction pursuant to 40 CFR Part 82, Subpart F.

37. If the permittee is subject to 40 CFR Part 82 and performs a service on motor (fleet) vehicles when this service involves refrigerant in the MVAC, the permittee is subject to all the applicable requirements as specified in 40 CFR Part 82, Subpart B, Servicing of Motor Vehicle Air Conditioners. The term "motor vehicle" as used in Subpart B does not include a vehicle in which final assembly of the vehicle has not been completed by the original equipment manufacturer. The term MVAC as used in Subpart B does not include the air-tight sealed refrigeration system used for refrigerated cargo or an air conditioning system on passenger buses using Hydrochlorofluorocarbon-22 refrigerant.

Risk Management Plan

38. If subject to Section 112(r) of the CAA and 40 CFR Part 68, the permittee shall register and submit to the USEPA the required data related to the risk management plan for reducing the probability of accidental releases of any regulated substances listed pursuant to Section 112(r)(3) of the CAA as amended in 40 CFR 68.130. The list of substances, threshold quantities, and accident prevention regulations promulgated under 40 CFR Part 68, do not limit in any way the general duty provisions under Section 112(r)(1).

39. If subject to Section 112(r) of the CAA and 40 CFR Part 68, the permittee shall comply with the requirements of 40 CFR Part 68, no later than the latest of the following dates as provided in 40 CFR 68.10(a):
    a. June 21, 1999,
    b. Three years after the date on which a regulated substance is first listed under 40 CFR 68.130, or
    c. The date on which a regulated substance is first present above a threshold quantity in a process.

40. If subject to Section 112(r) of the CAA and 40 CFR Part 68, the permittee shall submit any additional relevant information requested by any regulatory agency necessary to ensure compliance with the requirements of 40 CFR Part 68.

41. If subject to Section 112(r) of the CAA and 40 CFR Part 68, the permittee shall annually certify compliance with all applicable requirements of Section 112(r) as detailed in Rule 213(4)(c)). **(40 CFR Part 68)**

Emission Trading

42. Emission averaging and emission reduction credit trading are allowed pursuant to any applicable interstate or regional emission trading program that has been approved by the Administrator of the USEPA as a part of Michigan's State Implementation Plan. Such activities must comply with Rule 215 and Rule 216. **(R 336.1213(12))**

Permit to Install (PTI)

43. The process or process equipment included in this permit shall not be reconstructed, relocated, or modified unless a PTI authorizing such action is issued by the department, except to the extent such action is exempt from the PTI requirements by any applicable rule.[2] **(R 336.1201(1))**

44. The department may, after notice and opportunity for a hearing, revoke PTI terms or conditions if evidence indicates the process or process equipment is not performing in accordance with the terms and conditions of the PTI or is violating the department's rules or the CAA.[2] **(R 336.1201(8), Section 5510 of Act 451)**

45. The terms and conditions of a PTI shall apply to any person or legal entity that now or hereafter owns or operates the process or process equipment at the location authorized by the PTI. If a new owner or operator submits a written request to the department pursuant to Rule 219 and the department approves the request, this PTI will be amended to reflect the change of ownership or operational control. The request must include all of the information required by Subrules (1)(a), (b) and (c) of Rule 219. The written request shall be sent to the appropriate AQD District Supervisor, EGLE.[2] **(R 336.1219)**

46. If the installation, reconstruction, relocation, or modification of the equipment for which PTI terms and conditions have been approved has not commenced within 18 months of the original PTI issuance date, or has been interrupted for 18 months, the applicable terms and conditions from that PTI, as incorporated into the ROP, shall become void unless otherwise authorized by the department. Furthermore, the person to whom that PTI was issued, or the designated authorized agent, shall notify the department via the Supervisor, Permit Section, EGLE, AQD, P. O. Box 30260, Lansing, Michigan 48909, if it is decided not to pursue the installation, reconstruction, relocation, or modification of the equipment allowed by the terms and conditions from that PTI.[2] **(R 336.1201(4))**

Footnotes:
[1]This condition is state-only enforceable and was established pursuant to Rule 201(1)(b).
[2]This condition is federally enforceable and was established pursuant to Rule 201(1)(a).

B. SOURCE-WIDE CONDITIONS

Part B outlines the Source-Wide Terms and Conditions that apply to this stationary source. The permittee is subject to these special conditions for the stationary source in addition to the general conditions in Part A and any other terms and conditions contained in this ROP.

The permittee shall comply with all specific details in the special conditions and the underlying applicable requirements cited. If a specific condition type does not apply to this source, NA (not applicable) has been used in the table. If there are no Source-Wide Conditions, this section will be left blank.

C. EMISSION UNIT SPECIAL CONDITIONS

Part C outlines terms and conditions that are specific to individual emission units listed in the Emission Unit Summary Table. The permittee is subject to the special conditions for each emission unit in addition to the General Conditions in Part A and any other terms and conditions contained in this ROP.

The permittee shall comply with all specific details in the special conditions and the underlying applicable requirements cited. If a specific condition type does not apply, NA (not applicable) has been used in the table. If there are no conditions specific to individual emission units, this section will be left blank.

EMISSION UNIT SUMMARY TABLE

The descriptions provided below are for informational purposes and do not constitute enforceable conditions.

Emission Unit ID	Emission Unit Description (Including Process Equipment & Control Device(s))	Installation Date/ Modification Date	Flexible Group ID
EUPARTSCLEANERS	Multiple individual cleaning units that are subject to the same applicable requirements. The cleaning units are used in support of facility operations.	01-01-1994/ NA	FGPARTSCLEANERS
EUBOILER1	A 2490 MMBTU per hour dry bottom, tangential fired boiler with fuel oil startup capabilities. Emissions are currently controlled by low-NOx burners, sorbent injection (ACI) (activated carbon or other sorbent for mercury control), dry sorbent injection (DSI) (hydrated lime or other sorbent), and a pulse-jet fabric filter (PJFF) baghouse.	01-01-1958/ 04 23-2015	FGMATS_U12 FGBOILER12
EUBOILER2	A 3560 MMBTU per hour wall-fired (converted from cell burner) boiler with fuel oil startup capability. Emissions are controlled by low-NOx burners, selective catalytic reduction (SCR), sorbent injection (ACI) (activated carbon or other sorbent for mercury control), DSI (hydrated lime or other sorbent), and a PJFF baghouse.	01-01-1963/ 04-23-2015	FGMATS_U12 FGBOILER12
EUBOILER3	An 8240 MMBTU per hour dry bottom, wall-fired boiler with fuel oil startup capability. Emissions are controlled by low-NOx burners, SCR, sorbent injection (ACI) (activated carbon or other sorbent for mercury control), spray dry absorber (SDA), and PJFF baghouse.	02-01-1974/ 04-23-2015	FGMATS_U3
EUCOALHAND	Coal handling facility. Particulate emissions are controlled by 11 baghouses, enclosures, and dust suppression.	01-01-1958	NA

Emission Unit ID	Emission Unit Description (Including Process Equipment & Control Device(s))	Installation Date/ Modification Date	Flexible Group ID
EUSDA_U3	Lime preparation operations for Boiler 3 that support the SDA including storage silos, vertical ball mills, lime slurry transfer and product tanks. Emissions are controlled by bin vent filters and spray scrubbers (mill scrubbers). SDA operations for Boiler 3 includes lime slurry atomizer head tanks, recycle silos, recycle mix tanks, and recycle slurry storage tanks. Emissions are controlled by bin vent filters and a spray scrubber (recycle mix tank).	04-23-2015	NA
EUDSI_U12	Dry Sorbent Injection Material Handling for Boilers 1 and 2. Includes sorbent silos (hydrated lime or other sorbent) and pneumatic transfer; bin vent filters.	04-23-2015	NA
EUACI_U123	Activated carbon (or other sorbent) material handling including silos for Boiler Units 1, 2 and 3; with bin vent filters.	04-23-2015	NA
EUBYPRODUCT	There are three separate byproduct handling systems (one for each boiler). The system transfers the byproduct from the fabric filters (ash, spent lime, and sorbent) to the disposal silos. The equipment includes conveyance piping and byproduct transfer tanks, filter separator, vacuum exhausters, and conveying blowers from transfer tanks to flyash storage/disposal silos. Dry flyash handling facility is located at the landfill and is common to Boilers 1, 2, and 3 and consists of three flyash storage/disposal silos; with flyash truck dry load outs. Emissions control: The transfer tanks' byproduct vacuum exhauster filter separators exhaust to the boiler pulse-jet fabric filters (except as noted in the emission unit requirements); bin vent filters on the byproduct transfer tanks and flyash silos. Water added for flyash conditioning before flyash truck loading for disposal.	04-23-2015	NA
EUAUXBLR12	A 17 MMBTU/hr fuel oil-fired firetube auxiliary boiler servicing EUBOILER1 and EUBOILER2. This boiler is a limited use boiler.	01-01-1958	NA
EUAUXBLR3B	A 9.8 MMBTU/hr fuel oil fired auxiliary boiler providing heat to Plant 3.	11-2011	FGAUXBLRS3
EUAUXBLR3C	A 9.8 MMBTU/hr fuel oil fired auxiliary boiler providing heat to Plant 3.	11-2011	FGAUXBLRS3
EUCAT3DIESEL	A diesel-powered, stationary internal combustion engine rated at 9.3 MMBTU/hr heat input.	02-01-1974	NA

Emission Unit ID	Emission Unit Description (Including Process Equipment & Control Device(s))	Installation Date/ Modification Date	Flexible Group ID
EUWPDIESEL	Water Pump for EUSDA_U3 emergency flush certified to NSPS IIII Tier 3 requirements. A diesel-powered, stationary internal combustion engine rated at 130 HP (97 kW).	07-2016	FGNEWCIRICE
EUCATFIREPUMP3	A diesel-powered, stationary internal combustion Caterpillar 3406 model engine rated at 2.8 MMBTU/hr heat input; used as a fire pump.	01-2017	FGEXISTINGRICE
EUHPHSWP15001	A diesel-powered, stationary internal combustion engine rated at 3.05 MMBTU/hr heat input; Emergency Diesel Generator #1.	01-01-1958	FGEXISTINGRICE
EUHPHSWP15002	A diesel-powered, stationary internal combustion engine rated at 3.05 MMBTU/hr heat input; Emergency Diesel Generator #2.	01-01-1958	FGEXISTINGRICE
EUHPHSWP3000	A diesel-powered, stationary internal combustion engine rated at 2.58 MMBTU/hr heat input; Emergency Diesel Generator.	01-01-1958	FGEXISTINGRICE
EUCATDIESEL12	A 2,000-kilowatt (kW) diesel-fueled emergency engine manufactured in 2007 or later.	10-12-2012	NA
EUTRNCNTRDIESEL	A diesel-powered, stationary internal combustion engine rated at 1193 BHP; Emergency Diesel Generator.	08-2013	FGNEWCIRICE
EUGUARDSHK_ENG	A natural-gas, stationary internal combustion engine rated at 40 HP; Emergency Generator for the guard shack.	08-2015	NA

EUBOILER1
EMISSION UNIT CONDITIONS

DESCRIPTION

A 2490 MMBTU/hr dry bottom, tangential fired boiler with fuel oil startup capability. This emission unit is subject to 40 CFR Part 63, Subpart UUUUU (MATS) and 40 CFR Part 64 (CAM). All CAM requirements are in FGBOILER12 and all MATS requirements are in FGMATS_U12.

Flexible Group ID: FGBOILER12 and FGMATS_U12

POLLUTION CONTROL EQUIPMENT

Low-NOx burners,
Sorbent injection (ACI) (activated carbon or other sorbent for mercury control),
Dry sorbent injection (DSI) (hydrated lime or other sorbent), and
Pulse-jet fabric filter (PJFF) baghouse.

I. EMISSION LIMIT(S)

Pollutant	Limit	Time Period/ Operating Scenario	Equipment	Monitoring/ Testing Method	Underlying Applicable Requirements
1. Particulate matter (PM)	0.16 pound per 1,000 pounds exhaust gas, corrected to 50% excess air[2]	Hourly	EUBOILER1	SC V.1 (FGBOILER12, SC VI.1, COMS)	**R 336.1331(1)(c)**
2. NO_x	0.220 pound per MMBTU heat input[2,3,4]	Based on a 365-day Rolling Average Emission Rate[2,3,4]	EUBOILER1	SC VI.1	**"U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" paragraph 76; Act 451, Section 324.5503(b)**
3. SO_2	0.350 pounds per MMBTU heat input[2,3,4]	Based on a 30-day Rolling Average Emission Rate[2,3,4]	EUBOILER1	SC VI.1 SC VI.2	**"U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" paragraph 113; Act 451, Section 324.5503(b)**

Pollutant	Limit	Time Period/ Operating Scenario	Equipment	Monitoring/ Testing Method	Underlying Applicable Requirements
4. SO_2	0.290 pound per MMBTU heat input[2,3,4]	Based on a 90-day Rolling Average Emission Rate[2,3,4]	EUBOILER1	SC VI.1 SC VI.2	**"U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" paragraph 113; Act 451, Section 324.5503(b)**
5. PM	0.015 pound per MMBTU heat input[2,3,4]	Hourly[2,3,4]	EUBOILER1	SC V.2 (FGBOILER12, SC VI.1, COMS)	**"U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" paragraph 144; Act 451, Section 324.5503(b)**
6. Opacity	20%[2,3,4]	Per 6-minute period except for one 6-minute period per hour of not more than 27%[2,3,4]	EUBOILER1	SC VI.4	**"U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" paragraph 151; Act 451, Section 324.5503(b)**
7. SO_2	1.67 pounds per MMBTU heat input[2]	Monthly average, based on the average of the 31 previous operating days	EUBOILER1	SC VI.3	**R 336.1401(3), Table 41**

8. The permittee shall comply with the System-Wide Annual NOx Tonnage Limitations and System-Wide Annual SO_2 Tonnage Limitations specified in Appendix 11-A. Emissions from EUBOILER1 shall be counted toward the system-wide total emissions.[2,3,4] **("U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" paragraphs 98 & 129, Act 451, Section 324.5503(b))**

9. The permittee shall comply with the SO_2 and NO_x allowance surrender and super-compliance allowance provisions listed in Appendix 11-B: Allowance Provisions.[2,3,4] **("U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" paragraphs 101-109 and 132-140, Act 451, Section 324.5503(b))**

See Appendices 11-A and 11-B

II. MATERIAL LIMIT(S)

Material	Limit	Time Period/ Operating Scenario	Equipment	Monitoring/ Testing Method	Underlying Applicable Requirements
1. Coal – sulfur content	1.0% by weight, at a heat content of 12,000 BTU/lb[2]	Monthly average, based on the average of the 31 previous operating days	EUBOILER1	SC VI.3	**R 336.1401(3), Table 41**

III. PROCESS/OPERATIONAL RESTRICTION(S)

1. The permittee shall not operate EUBOILER1 unless a malfunction abatement plan (MAP) as described in Rule 911(2), for the emission control equipment (PJFF baghouse, ACI, DSI) is implemented and maintained. The MAP shall, at a minimum, specify the following:

   a. A complete preventative maintenance program including identification of the supervisory personnel responsible for overseeing the inspection, maintenance, and repair of air-cleaning devices, a description of the items or conditions that shall be inspected, the frequency of the inspections or repairs, and an identification of the major replacement parts that shall be maintained in inventory for quick replacement.

   b. An identification of the source and air-cleaning device operating variables that shall be monitored to detect a malfunction or failure, the normal operating range of these variables, and a description of the method of monitoring or surveillance procedures.

   c. A description of the corrective procedures or operational changes that shall be taken in the event of a malfunction or failure to achieve compliance with the applicable emission limits.

   If at any time the MAP fails to address or inadequately addresses an event that meets the characteristics of a malfunction, the permittee shall amend the MAP within 45 days after such an event occurs. The permittee shall also amend the MAP within 45 days, if new equipment is installed or upon request from the District Supervisor. The permittee shall submit the MAP and any amendments to the MAP to the AQD District Supervisor for review and approval. If the AQD does not notify the permittee within 90 days of submittal, the MAP or amended MAP shall be considered approved. Until an amended plan is approved, the permittee shall implement corrective procedures or operational changes to achieve compliance with all applicable emission limits.[2] **(R 336.1910, R 336.1911)**

2. The permittee shall continuously operate the PM Control Device for EUBOILER1 and use good air pollution control practices to maximize the PM emission reductions at all times when the unit is in operation. The requirements of Appendix 3-F shall be met.[2,3,4] **("U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" – paragraph 141, Act 451, Section 324.5503(b))**

3. The permittee shall not operate the boiler, including startup and shutdown, unless the corresponding PJFF baghouse is installed and operating properly, in accordance with safe operating practices.[2] **(R 336.1910)**

4. The permittee shall not burn freeze conditioning/dust suppression agents unless PJFF baghouses are installed and operating properly, in accordance with safe operating practices.[2] **(R 336.1910)**

See Appendix 3-F

IV. DESIGN/EQUIPMENT PARAMETER(S)

1. The permittee shall not operate EUBOILER1 unless the low-NOx burners, the DSI, the ACI sorbent injection (for mercury control), and PJFF baghouse are installed, maintained, and operated in a satisfactory manner. Satisfactory manner includes operating and maintaining each control device in accordance with an approvable MAP for EUBOILER1 control equipment as required in SC III.1.[2] **(R 336.1910)**

2. The permittee shall not operate EUBOILER1 unless the low-NO_x burners, including over fire air processes, are Continuously Operated.[2,3,4] **("U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" – paragraph 75, Act 451, Section 324.5503(b))**

3. The permittee shall not operate EUBOILER1 unless the DSI system is Continuously Operated.[2,3,4] **("U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" – paragraph 113, Act 451, Section 324.5503(b))**

4. The permittee shall not operate EUBOILER1 unless the PJFF baghouse unit is Continuously Operated.[2,3,4] **("U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" – paragraph 144, Act 451, Section 324.5503(b))**

5. The permittee shall continuously operate the PM control devices being vented to a combined stack associated with FGBOILER12.[2,3,4] **("U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" – paragraph 142, Act 451, Section 324.5503(b))**

V. TESTING/SAMPLING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. Every three (3) years, or more frequently upon request of the AQD, the permittee shall verify PM emission rates from EUBOILER1 by testing at the owner's expense, in accordance with the Department requirements. Testing shall be performed using an approved USEPA Method listed in 40 CFR Part 60, Appendix A, Reference Method 17 (Determination of Particulate Emissions from Stationary Sources (In-stack Filtration Method)), Reference Method 5 or "MATS" 5, or other acceptable test method(s). An alternate method, or a modification to the approved USEPA Method, may be specified in an AQD-approved Test Protocol. No less than 30 days prior to testing, the permittee shall submit a complete test plan to the AQD Technical Programs Unit and District Office. The AQD must approve the final plan prior to testing, including any modifications to the method in the test protocol that are proposed after initial submittal. The permittee must submit a complete report of the test results to the AQD Technical Programs Unit and District Office within 60 days following the last date of the test.[2] **(R 336.1213(3), R 336.2001, R 336.2003, R 336.2004)**
2. The permittee shall conduct a stack test for PM pursuant to the provisions found in Appendix 5: PM Emissions Testing and Monitoring Requirements. Subsequent stack tests for PM shall be conducted pursuant to the schedule and provisions found in Appendix 5: PM Emissions Testing and Monitoring Requirements.[2,3,4] **("U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" – paragraph 153, Act 451, Section 324.5503(b))**

3. The permittee shall notify the AQD Technical Programs Unit Supervisor and the District Supervisor not less than 7 days of the time and place before performance tests are conducted.[2] **(R 336.2001(3))**

4. The permittee shall assess opacity using USEPA Reference Method 9 - "Visual Determination of the Opacity of Emissions from Stationary Sources," upon the request of AQD.[2] **(R 336.1301)**

See Appendix 5

VI. MONITORING/RECORDKEEPING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. For purposes of determining compliance with the Rolling Average Emission Rates for NO_x and SO_2 as found in SC I.2, I.3, and I.4, the permittee shall install and operate CEMS in accordance with the procedures of 40 CFR Part 75, except that the NO_x and SO_2 emissions data need not be bias adjusted and the missing data substitution procedures of 40 CFR Part 75 shall not apply. If applicable, diluent capping (i.e., 5% CO_2) will be applied to the NO_x emission rate for any hours where the measured CO_2 concentration is less than 5% following the procedures in 40 CFR Part 75, Appendix F, Section 3.3.4.1.[2,3,4] **("U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" paragraphs 99 and 130, Act 451, Section 324.5503(b))**

2. The permittee shall monitor unit level SO_2 concentrations and gas flow, using CEMS, as installed, maintained, and operated in accordance with 40 CFR Part 75.[2,3,4] **("U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" paragraph 116, Act 451, Section 324.5503(b))**

3. The permittee shall monitor gas flow, SO_2, CO_2, and NOx emissions using CEMS, as installed, maintained, and operated in accordance with the provisions of 40 CFR Part 75.[2] **(R 336.1401, R 336.2101)**

4. The permittee shall monitor and record the opacity from each boiler using a Continuous Opacity Monitoring System (COMS), installed, operated and maintained in accordance with 40 CFR Part 60, Appendix B.[2] **(R 336.1301, R 336.2101)**

See Appendices 3-A, 3-B, and 3-D

VII. REPORTING

1. Prompt reporting of deviations pursuant to General Conditions 21 and 22 of Part A. **(R 336.1213(3)(c)(ii))**

2. Semiannual reporting of monitoring and deviations pursuant to General Condition 23 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for reporting period July 1 to December 31 and September 15 for reporting period January 1 to June 30. **(R 336.1213(3)(c)(i))**

3. Annual certification of compliance pursuant to General Conditions 19 and 20 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for the previous calendar year. **(R 336.1213(4)(c))**

4. The permittee shall submit any performance test reports, including RATA reports, to the AQD Technical Programs Unit and District Office, in a format approved by the AQD. **(R 336.1213(3)(c), R 336.2001(5))**

See Appendix 8

VIII. STACK/VENT RESTRICTION(S)

The exhaust gases from the stacks listed in the table below shall be discharged unobstructed vertically upwards to the ambient air unless otherwise noted:

Stack & Vent ID	Maximum Exhaust Dimensions (inches)	Minimum Height Above Ground (feet)	Underlying Applicable Requirements
1. SVBLR12	228[2]	400[2]	**R 336.1225** **R 336.2803** **R 336.2804** **40 CFR 52.21 (c) and (d)**

IX. OTHER REQUIREMENT(S)

1. The permittee shall comply with the acid rain permitting provisions of 40 CFR Part 72.1 to 72.94, as outlined in a complete Phase II, Acid Rain Permit issued by the AQD. Phase II, Acid Rain Permit No. MI-AR-1710-2020is hereby incorporated into this ROP as Appendix 9. **(R 336.1902(1)(q))**

2. The permittee shall not allow the emission of an air pollutant to exceed the amount of any emission allowances that an affected source lawfully holds as of the allowance transfer deadline pursuant to R 336.1902(1)(q) and 40 CFR Part 72.9(c)(1)(i). **(R 336.1213(10))**

3. The permittee shall comply with the provisions of the Cross-State Air Pollution Rule NO_X Annual Trading Program, as specified in 40 CFR Part 97, Subpart AAAAA, and identified in Appendix 10. **(40 CFR Part 97, Subpart AAAAA)**

4. The permittee shall comply with the provisions of the Cross-State Air Pollution Rule NO_X Ozone Season Group 2 Trading Program, as specified in 40 CFR Part 97, Subpart EEEEE, and identified in Appendix 10. **(40 CFR Part 97, Subpart EEEEE)**

5. The permittee shall comply with the provisions of the Cross-State Air Pollution Rule SO_2 Group 1 Trading Program, as specified in 40 CFR Part 97, Subpart CCCCC, and identified in Appendix 10. **(40 CFR Part 97, Subpart CCCCC)**

6. The permittee shall comply with applicable provisions of Act 451 Part 15 EMISSION LIMITATIONS AND PROHIBITIONS-MERCURY.[2] **(R 336.2503(1))**

7. The permittee shall comply with all applicable requirements of 40 CFR Part 64 as specified in FGBOILER12. **(40 CFR Part 64)**

8. The permittee shall comply with the applicable requirements of 40 CFR Part 63, Subpart UUUUU - National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-fired Electric Utility Steam Generating Units, as specified in FGMATS_U12.[2] **(40 CFR Part 63, Subpart UUUUU)**

Footnotes:
[1]This condition is state only enforceable and was established pursuant to Rule 201(1)(b).
[2]This condition is federally enforceable and was established pursuant to Rule 201(1)(a).
[3]This condition is federally enforceable and was originally established in the consent decree settling, "U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" and also pursuant to Act 451, Section 324.5503(b), and will remain in effect after termination of the consent decree.
[4]Definitions specific to this condition may be found in Appendix 1-B: Definitions Applicable to Specified Permit Conditions.

EUBOILER2
EMISSION UNIT CONDITIONS

DESCRIPTION

A 3560 MMBTU/hr wall-fired boiler with fuel oil startup capability. This emission unit is subject to 40 CFR Part 64 (CAM) and 40 CFR Part 63, Subpart UUUUU (MATS). All CAM requirements are in FGBOILER12, and all MATS requirements are in FGMATS_U12.

Flexible Group ID: FGBOILER12 and FGMATS_U12

POLLUTION CONTROL EQUIPMENT

Low-NOx burners,
Selective catalytic reduction (SCR),
Sorbent injection (ACI) (activated carbon or other sorbent for mercury control),
Dry sorbent injection (DSI) (hydrated lime or other sorbent), and
Pulse-jet fabric filter (PJFF) baghouse.

I. EMISSION LIMIT(S)

Pollutant	Limit	Time Period/ Operating Scenario	Equipment	Monitoring/ Testing Method	Underlying Applicable Requirements
1. Particulate matter (PM)	0.15 pound per 1,000 pounds exhaust gas, corrected to 50% excess air[2]	Hourly	EUBOILER2	SC V.1 (FGBOILER12, SC VI.1, COMS)	**R 336.1331(1)(c)**
2. NO_x	0.100 pound per MMBTU heat input[2,3,4]	Based on a 30-day Rolling Average Emission Rate[2,3,4]	EUBOILER2	SC VI.1	**"U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" paragraph 78; Act 451, Section 324.5503(b)**
3. NO_x	0.080 pound per MMBTU heat input[2,3,4]	Based on a 90-day Rolling Average Emission Rate[2,3,4]	EUBOILER2	SC VI.1	**"U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" paragraph 79; Act 451, Section 324.5503(b)**

	Pollutant	Limit	Time Period/ Operating Scenario	Equipment	Monitoring/ Testing Method	Underlying Applicable Requirements
4.	SO_2	0.320 pound per MMBTU heat input[2,3,4]	Based on a 365-day Rolling Average Emission Rate[2,3,4]	EUBOILER2	SC VI.1 SC VI.2	**"U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" paragraph 114; Act 451, Section 324.5503(b)**
5.	PM	0.015 pound per MMBTU heat input[2,3,4]	Hourly[2,3,4]	EUBOILER2	SC V.2 (FGBOILER12, SC VI.1, COMS)	**"U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" paragraph 145; Act 451, Section 324.5503(b)**
6.	SO_2	1.67 pounds per MMBTU heat input[2]	Monthly average, based on the average of the 31 previous operating days	EUBOILER2	SC VI.3	**R 336.1401(3), Table 41**
7.	Opacity	20%[2,3,4]	Per 6-minute period except for one 6-minute period per hour of not more than 27%[2,3,4]	EUBOILER2	SC VI.4	**"U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" paragraph 151; Act 451, Section 324.5503(b)**

8. The permittee shall comply with the System-Wide Annual NOx Tonnage Limitations and System-Wide Annual SO_2 Tonnage Limitations specified in Appendix 11-A. Emissions from EUBOILER2 shall be counted toward the system-wide total emissions.[2,3,4] **("U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" paragraphs 98 & 129, Act 451, Section 324.5503(b))**

9. The permittee shall comply with the SO_2 and NO_x allowance surrender and super-compliance allowance provisions listed in Appendix 11-B: Allowance Provisions.[2,3,4] **("U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" paragraphs 101-109 and 132-140, Act 451, Section 324.5503(b))**

See Appendices 11-A and 11-B

II. MATERIAL LIMIT(S)

	Material	Limit	Time Period/ Operating Scenario	Equipment	Monitoring/ Testing Method	Underlying Applicable Requirements
1.	Coal – sulfur content	1.0% by weight, at a heat content of 12,000 BTU/lb[2]	Monthly average, based on the average of the 31 previous operating days	EUBOILER2	SC VI.3	**R 336.1401(3), Table 41**

III. PROCESS/OPERATIONAL RESTRICTION(S)

1. The permittee shall not operate EUBOILER2 unless a malfunction abatement plan (MAP) as described in Rule 911(2), for the emission control equipment (PJFF baghouse, ACI, DSI, and SCR) is implemented and maintained. The MAP shall, at a minimum, specify the following:

   a. A complete preventative maintenance program including identification of the supervisory personnel responsible for overseeing the inspection, maintenance, and repair of air-cleaning devices, a description of the items or conditions that shall be inspected, the frequency of the inspections or repairs, and an identification of the major replacement parts that shall be maintained in inventory for quick replacement.

   b. An identification of the source and air-cleaning device operating variables that shall be monitored to detect a malfunction or failure, the normal operating range of these variables, and a description of the method of monitoring or surveillance procedures.

   c. A description of the corrective procedures or operational changes that shall be taken in the event of a malfunction or failure to achieve compliance with the applicable emission limits.

   If at any time the MAP fails to address or inadequately addresses an event that meets the characteristics of a malfunction, the permittee shall amend the MAP within 45 days after such an event occurs. The permittee shall also amend the MAP within 45 days if new equipment is installed or upon request from the District Supervisor. The permittee shall submit the MAP and any amendments to the MAP to the AQD District Supervisor for review and approval. If the AQD does not notify the permittee within 90 days of submittal, the MAP or amended MAP shall be considered approved. Until an amended plan is approved, the permittee shall implement corrective procedures or operational changes to achieve compliance with all applicable emission limits.[2] **(R 336.1910, R 336.1911)**

2. The permittee shall continuously operate the PM Control Device for EUBOILER2 and use good air pollution control practices to maximize the PM emission reductions at all times when the unit is in operation. The requirements of Appendix 3-F shall be met.[2,3,4] **("U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" – paragraph 141, Act 451, Section 324.5503(b))**

3. The permittee shall not operate the boiler, including startup and shutdown, unless the corresponding PJFF baghouse is installed and operating properly, in accordance with safe operating practices.[2] **(R 336.1910)**

4. The permittee shall not burn freeze conditioning/dust suppression agents unless PJFF baghouses are installed and operating properly, in accordance with safe operating practices.[2] **(R 336.1910)**

See Appendix 3-F

IV. DESIGN/EQUIPMENT PARAMETER(S)

1. The permittee shall not operate EUBOILER2 unless the low-NOx burners, the SCR, DSI, ACI sorbent injection (for mercury control), and PJFF baghouse are installed, maintained, and operated in a satisfactory manner. Satisfactory manner includes operating and maintaining each control device in accordance with an approvable MAP for EUBOILER2 as required in SC III.1.[2] **(R 336.1910)**

2. The permittee shall not operate EUBOILER2 unless the SCR and PJFF baghouse are continuously operated.[2,3,4] **("U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" – paragraphs 77 and 145, Act 451, Section 324.5503(b))**

3. The permittee shall not operate EUBOILER2 unless the DSI system is continuously operated.[2,3,4] **("U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" – paragraph 114, Act 451, Section 324.5503(b))**

4. The permittee shall continuously operate the PM control devices being vented to a combined stack associated with FGBOILER12.[2,3,4] **("U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" – paragraph 142, Act 451, Section 324.5503(b))**

V. TESTING/SAMPLING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. Every three (3) years, or more frequently upon request of the AQD, the permittee shall verify PM emission rates from EUBOILER2 by testing at the owner's expense, in accordance with the Department requirements. Testing shall be performed using an approved USEPA Method listed in 40 CFR Part 60, Appendix A Reference Method 17 (Determination of Particulate Emissions from Stationary Sources (In-stack Filtration Method)), Reference Method 5, "MATS" Reference Method 5, or other acceptable test method(s). An alternate method, or a modification to the approved USEPA Method, may be specified in an AQD-approved Test Protocol. No less than 30 days prior to testing, the permittee shall submit a complete test plan to the AQD Technical Programs Unit and District Office. The AQD must approve the final plan prior to testing, including any modifications to the method in the test protocol that are proposed after initial submittal. The permittee must submit a complete report of the test results to the AQD Technical Programs Unit and District Office within 60 days following the last date of the test.[2] **(R 336.1213(3), R 336.1201(3), R 336.2001, R 336.2003, R 336.2004)**

2. The permittee shall conduct a stack test for PM pursuant to the provisions found in Appendix 5: PM Emissions Testing and Monitoring Requirements. Subsequent stack tests for PM shall be conducted pursuant to the schedule and provisions found in Appendix 5: PM Emissions Testing and Monitoring Requirements.[2,3,4] **("U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" – paragraph 153, Act 451, Section 324.5503(b))**

3. The permittee shall notify the AQD Technical Programs Unit Supervisor and the District Supervisor no less than 7 days prior to the anticipated test date.[2] **(R 336.2001(3))**

4. The permittee shall assess opacity using USEPA Reference Method 9 - "Visual Determination of the Opacity of Emissions from Stationary Sources", upon the request of AQD.[2] **(R 336.1301)**

See Appendix 5

VI. MONITORING/RECORDKEEPING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. For purposes of determining compliance with the Rolling Average Emission Rates for NO_x and SO_2 as found in SC I.2, I.3, and I.4., the permittee shall install and operate CEMS in accordance with the procedures of 40 CFR Part 75, except that the NO_x and SO_2 emissions data need not be bias adjusted and the missing data substitution procedures of 40 CFR Part 75 shall not apply. If applicable, diluent capping (i.e., 5% CO_2) will be applied to the NO_x emission rate for any hours where the measured CO_2 concentration is less than 5% following the procedures in 40 CFR Part 75, Appendix F, Section 3.3.4.1.[2,3,4] **("U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" paragraphs 99 and 130, Act 451, Section 324.5503(b))**

2. The permittee shall monitor SO_2 concentrations and gas flow using CEMS, as installed, maintained, and operated in accordance with 40 CFR Part 75.[2,3,4] **("U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" paragraph 116, Act 451, Section 324.5503(b))**

3. The permittee shall monitor gas flow, SO_2, CO_2, and NOx emissions using CEMS, as installed, maintained, and operated in accordance with the provisions of 40 CFR Part 75.[2] **(R 336.1401, R 336.2101)**

4. The permittee shall monitor and record the opacity from each boiler using a Continuous Opacity Monitoring System (COMS), installed, operated and maintained in accordance with 40 CFR Part 60, Appendix B.[2] **(R 336.1301, R 336.2101)**

See Appendices 3-A, 3-B, and 3-D

VII. REPORTING

1. Prompt reporting of deviations pursuant to General Conditions 21 and 22 of Part A. **(R 336.1213(3)(c)(ii))**

2. Semiannual reporting of monitoring and deviations pursuant to General Condition 23 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for reporting period July 1 to December 31 and September 15 for reporting period January 1 to June 30. **(R 336.1213(3)(c)(i))**

3. Annual certification of compliance pursuant to General Conditions 19 and 20 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for the previous calendar year. **(R 336.1213(4)(c))**

4. The permittee shall submit any performance test reports, including RATA reports to the AQD Technical Programs Unit and District Office, in a format approved by the AQD. **(R 336.1213(3)(c), R 336.2001(5))**

See Appendix 8

VIII. STACK/VENT RESTRICTION(S)

The exhaust gases from the stacks listed in the table below shall be discharged unobstructed vertically upwards to the ambient air unless otherwise noted:

Stack & Vent ID	Maximum Exhaust Dimensions (inches)	Minimum Height Above Ground (feet)	Underlying Applicable Requirements
1. SVBLR12	228[2]	400[2]	**R 336.1225** **R 336.2803** **R 336.2804** **40 CFR 52.21 (c) and (d)**

IX. OTHER REQUIREMENT(S)

1. The permittee shall comply with the acid rain permitting provisions of 40 CFR 72.1 to 72.94, as outlined in a complete Phase II, Acid Rain Permit issued by the AQD. Phase II, Acid Rain Permit No. MI-AR-1710-2020 is hereby incorporated into this ROP as Appendix 9. **(R 336.1902(1)(q))**

2. The permittee shall not allow the emission of an air pollutant to exceed the amount of any emission allowances that an affected source lawfully holds as of the allowance transfer deadline pursuant to R 336.1902(1)(q) and 40 CFR 72.9(c)(1)(i). **(R 336.1213(10))**

3. The permittee shall comply with the provisions of the Cross-State Air Pollution Rule NO_X Annual Trading Program, as specified in 40 CFR Part 97, Subpart AAAAA, and identified in Appendix 10. **(40 CFR Part 97, Subpart AAAAA)**

4. The permittee shall comply with the provisions of the Cross-State Air Pollution Rule NO_X Ozone Season Group 2 Trading Program, as specified in 40 CFR Part 97, Subpart EEEEE, and identified in Appendix 10. **(40 CFR Part 97, Subpart EEEEE)**

5. The permittee shall comply with the provisions of the Cross-State Air Pollution Rule SO_2 Group 1 Trading Program, as specified in 40 CFR Part 97, Subpart CCCCC, and identified in Appendix 10. **(40 CFR Part 97, Subpart CCCCC)**

6. The permittee shall comply with applicable provisions of Act 451 Part 15 EMISSION LIMITATIONS AND PROHIBITIONS—MERCURY.[2] **(R 336.2503(1))**

7. The permittee shall comply with all applicable requirements of 40 CFR Part 64 as specified in FGBOILER12. **(40 CFR Part 64)**

8. The permittee shall comply with the applicable requirements of 40 CFR Part 63, Subpart UUUUU - National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-fired Electric Utility Steam Generating Units, as specified in FGMATS_U12.[2] **(40 CFR Part 63, Subpart UUUUU)**

See Appendices 11-A and 11-B

Footnotes:
[1]This condition is state only enforceable and was established pursuant to Rule 201(1)(b).
[2]This condition is federally enforceable and was established pursuant to Rule 201(1)(a).
[3]This condition is federally enforceable and was originally established in the consent decree settling, "U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" and also pursuant to Act 451, Section 324.5503(b), and will remain in effect after termination of the consent decree.
[4]Definitions specific to this condition may be found in Appendix 1-B: Definitions Applicable to Specified Permit Conditions.

EUBOILER3
EMISSION UNIT CONDITIONS

DESCRIPTION

An 8240 MMBTU/hr dry bottom, wall-fired boiler with fuel oil startup capability. This emission unit is subject to 40 CFR Part 63, Subpart UUUUU (MATS). The MATS requirements are in FGMATS_U3.

Flexible Group ID: FGMATS_U3

POLLUTION CONTROL EQUIPMENT

Low-NOx burners,
Selective catalytic reduction (SCR),
Sorbent injection (ACI) (activated carbon or other sorbent for mercury control),
Spray dry absorber (SDA), and
Pulse-jet fabric filter (PJFF) baghouse.

I. EMISSION LIMIT(S)

Pollutant	Limit	Time Period/ Operating Scenario	Equipment	Monitoring/ Testing Method	Underlying Applicable Requirements
1. Opacity	20%[2]	Per 6-minute period except for one 6-minute period per hour of not more than 27%	EUBOILER3	SC VI.2	**40 CFR 60.42(a)(2), R 336.1301**
2. Opacity	20%[2,3,4]	Per 6-minute period except for one 6-minute period per hour of not more than 27%	EUBOILER3	SC VI.2	**"U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" paragraph 151; Act 451, Section 324.5503(b)**
3. PM	0.10 pound per MMBTU heat input[2]	Hourly	EUBOILER3	SC V.1 SC VI.2 SC VI. 4	**40 CFR 60.42(a)(1)**
4. PM	370 pounds per hour[2]	Hourly	EUBOILER3	SC V.1 SC VI.2 SC VI.4	**R 336.1205(3)**
5. PM	1,080 tons per year[2]	Based on a 12-month rolling time period as determined at the end of each calendar month	EUBOILER3	SC V.1 SC VI.2 SC VI.4	**R 336.1205(3)**

Pollutant	Limit	Time Period/ Operating Scenario	Equipment	Monitoring/ Testing Method	Underlying Applicable Requirements
6. PM	0.015 pound per MMBTU heat input[2,3,4]	Based on a 3-hr rolling average in accordance with SC V.4 and SC VI.4[2,3,4]	EUBOILER3	SC V.3, SC V.4 (if applicable) SC VI.4	**"U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" paragraph 146; Act 451, Section 324.5503(b)**
7. SO_2	1.2 pounds per MMBTU heat input[2]	Continuous	EUBOILER3	SC VI.1	**40 CFR 60.43(a)(2)**
8. SO_2	10,500 pounds per hour[2]	Based on a daily average	EUBOILER3	SC VI.1	**R 336.1205(3)**
9. SO_2	31,650 tons per year[2]	Based on a 12-month rolling time period as determined at the end of each calendar month	EUBOILER3	SC VI.1	**R 336.1205(3)**
10. SO_2	0.085 pound per MMBTU heat input[2,3,4]	Based on a 30-day Rolling Average[2,3,4]	EUBOILER3	SC VI.3	**"U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" paragraph 112; Act 451, Section 324.5503(b)**
11. SO_2	0.070 pound per MMBTU heat input[2,3,4]	Based on a 365-day Rolling Average Emission Rate[2,3,4]	EUBOILER3	SC VI.3	**"U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" paragraph 112; Act 451, Section 324.5503(b)**
12. NOx	0.70 pound per MMBTU heat input[2]	Per 3-hour rolling time period, as determined each hour the boiler operates	EUBOILER3	SC VI.1	**40 CFR 60.44(a)(3)**
13. NOx	6,130 pounds per hour[2]	Based on a daily average	EUBOILER3	SC VI.1	**R 336.1205(3)**
14. NOx	18,750 tons per year[2]	Based on a 12-month rolling time period as determined at the end of each calendar month	EUBOILER3	SC VI.1	**R 336.1205(3)**

Pollutant	Limit	Time Period/ Operating Scenario	Equipment	Monitoring/ Testing Method	Underlying Applicable Requirements
15. NOx	0.100 pound per MMBTU heat input[2,3,4]	Based on a 30-day Rolling Average Emission Rate[2,3,4]	EUBOILER3	SC VI.3	**"U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" paragraph 81; Act 451, Section 324.5503(b)**
16. NOx	0.080 pound per MMBTU heat input[2,3,4]	Based on a 90-day Rolling Average Emission Rate[2,3,4]	EUBOILER3	SC VI.3	**"U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" paragraph 82; Act 451, Section 324.5503(b)**

17. The permittee shall comply with the System-Wide Annual NOx Tonnage Limitations and System-Wide Annual SO_2 Tonnage Limitations specified in Appendix 11-A. Emissions from EUBOILER3 shall be counted toward the system-wide total emissions.[2,3,4] **("U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" paragraphs 98 & 129, Act 451, Section 324.5503(b))**

18. The permittee shall comply with the SO_2 and NO_x allowance surrender and super-compliance allowance provisions listed in Appendix 11-B: Allowance Provisions.[2,3,4] **("U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" paragraphs 101-109 and 132-140, Act 451, Section 324.5503(b))**

See Appendix 11-A and Appendix 11-B

II. MATERIAL LIMIT(S)

NA

III. PROCESS/OPERATIONAL RESTRICTION(S)

1. The permittee shall not burn freeze conditioning/dust suppression agents unless the boiler and corresponding particulate control device are operating properly.[2] **(R 336.1910)**

2. The permittee shall not operate the boiler, including startup and shutdown, unless the corresponding PJFF baghouse is installed and operating properly, in accordance with safe operating practices.[2] **(R 336.1910)**

3. The permittee shall not operate EUBOILER3 unless a malfunction abatement plan (MAP) as described in Rule 911(2), for emission control equipment (PJFF baghouse, ACI, SDA, and SCR) is implemented and maintained. The MAP shall, at a minimum, specify the following:

   a. A complete preventative maintenance program including identification of the supervisory personnel responsible for overseeing the inspection, maintenance, and repair of air-cleaning devices, a description of the items or conditions that shall be inspected, the frequency of the inspections or repairs, and an identification of the major replacement parts that shall be maintained in inventory for quick replacement.

b. An identification of the source and air-cleaning device operating variables that shall be monitored to detect a malfunction or failure, the normal operating range of these variables, and a description of the method of monitoring or surveillance procedures.

c. A description of the corrective procedures or operational changes that shall be taken in the event of a malfunction or failure to achieve compliance with the applicable emission limits.

If at any time the MAP fails to address or inadequately addresses an event that meets the characteristics of a malfunction, the permittee shall amend the MAP within 45 days after such an event occurs. The permittee shall also amend the MAP within 45 days if new equipment is installed or upon request from the District Supervisor. The permittee shall submit the MAP and any amendments to the MAP to the AQD District Supervisor for review and approval. If the AQD does not notify the permittee within 90 days of submittal, the MAP or amended MAP shall be considered approved. Until an amended plan is approved, the permittee shall implement corrective procedures or operational changes to achieve compliance with all applicable emission limits.[2] **(R 336.1910, R 336.1911)**

4. The permittee shall comply with all provisions of the federal Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction is Commenced after August 17, 1971, as specified in 40 CFR Part 60, Subparts A and D, as they apply to EUBOILER3.[2] **(40 CFR Part 60, Subparts A and D)**

5. The permittee shall continuously operate the PM Control Device for EUBOILER3 and use good air pollution control practices to maximize the PM emission reductions at all times when the unit is in operation. The requirements of Appendix 3-F shall be met.[2,3,4] **("U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" – paragraph 141, Act 451, Section 324.5503(b))**

See Appendix 3-F

IV. DESIGN/EQUIPMENT PARAMETER(S)

1. The permittee shall not operate EUBOILER3 unless the low-NOx burners, the SCR, SDA, ACI sorbent injection (for mercury control), and PJFF baghouse are installed, maintained, and operated in a satisfactory manner. Satisfactory manner includes operating and maintaining each control device in accordance with an approvable MAP for EUBOILER3 as required in SC III.5.[2] **(R 336.1910)**

2. The permittee shall not operate EUBOILER3 unless the SCR is Continuously Operated.[2,3,4] **("U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" – paragraph 80, Act 451, Section 324.5503(b))**

3. The permittee shall not operate EUBOILER3 unless the SDA and PJFF baghouse units are Continuously Operated.[2,3,4] **("U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" – paragraphs 112 and 146, Act 451, Section 324.5503(b))**

V. TESTING/SAMPLING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. Every three (3) years, or more frequently upon request of the AQD, the permittee shall verify PM emission rates from EUBOILER3 by testing at the owner's expense, in accordance with the Department requirements. Testing shall be performed using an approved USEPA Method listed in 40 CFR Part 60, Appendix A, Reference Method 17 (Determination of Particulate Emissions from Stationary Sources (in-stack Filtration Method) Reference Method 5, "MATS" Reference Method 5, or other acceptable test method(s). An alternate method, or a modification to the approved USEPA Method, may be specified in an AQD-approved Test Protocol. No less than 30 days prior to testing, the permittee shall submit a complete test plan to the AQD Technical Programs Unit and District Office. The AQD must approve the final plan prior to testing, including any modifications to the method in the test protocol that are proposed after initial submittal. The permittee must submit a complete report of the test results to the AQD Technical Programs Unit and District Office within 60 days following the last date of the test.[2] **(R 336.2001, R 336.2003, R 336.2004)**

2. The permittee shall notify the AQD no less than 7 days prior to the anticipated test date.[2] **(R 336.2001(3))**

3. The permittee shall conduct a stack test for PM pursuant to the provisions found in Appendix 5: PM Emissions Testing and Monitoring Requirements. Subsequent stack tests for PM shall be conducted pursuant to the schedule and provisions found in Appendix 5: PM Emissions Testing and Monitoring Requirements.[2,3,4] **("U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" – paragraph 153, Act 451, Section 324.5503(b))**

4. As an alternative to the requirements of SC V.3 PM stack testing, the permittee may forego stack testing and instead demonstrate continuous compliance with SC I.7 PM filterable emission limit by using the PM CEMS pursuant to conditions contained in Appendix 5: PM Emissions Testing and Monitoring Requirements, and Appendix 3-E: PM CEMS.[2,3,4] **("U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" – paragraph 157, Act 451, Section 324.5503(b))**

See Appendices 3-E and 5

VI. MONITORING/RECORDKEEPING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. The permittee shall monitor gas flow, SO_2, CO_2, and NOx emissions using CEMS, as installed, maintained, and operated in accordance with the provisions of 40 CFR Part 75.[2] **(R 336.1205(3), R 336.2101, 40 CFR Part 60)**

2. The permittee shall monitor and record the opacity from the boiler using a Continuous Opacity Monitoring System (COMS), installed, operated and maintained in accordance with 40 CFR Part 60, Appendix B.[2] **(R 336.1301, R 336.2101, 40 CFR 60.42(a)(2))**

3. For purposes of determining compliance with the Rolling Average Emission Rates for NO_x and SO_2 as found in SC I.10, I.11, I.15, and I.16, the permittee shall install and operate CEMS in accordance with the procedures of 40 CFR Part 75, except that the NO_x and SO_2 emissions data need not be bias adjusted and the missing data substitution procedures of 40 CFR Part 75 shall not apply. If applicable, diluent capping (i.e., 5% CO_2) will be applied to the NO_x emission rate for any hours where the measured CO_2 concentration is less than 5% following the procedures in 40 CFR Part 75, Appendix F, Section 3.3.4.1.[2,3,4] **("U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" paragraphs 99 and 130, Act 451, Section 324.5503(b))**

4. The permittee shall install and continuously operate a PM CEMS pursuant to the conditions contained in Appendix 3-E: PM CEMS.[2,3,4] **("U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" paragraphs 159, 163, Act 451, Section 324.5503(b))**

See Appendices 3-A through 3-F

VII. REPORTING

1. Prompt reporting of deviations pursuant to General Conditions 21 and 22 of Part A. **(R 336.1213(3)(c)(ii))**

2. Semiannual reporting of monitoring and deviations pursuant to General Condition 23 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for reporting period July 1 to December 31 and September 15 for reporting period January 1 to June 30. **(R 336.1213(3)(c)(i))**

3. Annual certification of compliance pursuant to General Conditions 19 and 20 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for the previous calendar year. **(R 336.1213(4)(c))**

4. The permittee shall submit any performance test reports, including RATA reports to the AQD Technical Programs Unit and District Office, in a format approved by the AQD. **(R 336.1213(3)(c), R 336.2001(5))**

5. Quarterly reporting of monthly excess sulfur dioxide, and nitrogen oxide emissions (including the nature and cause of the periods of excess emissions), and of the dates and times of the monitoring systems being inoperative. Each quarterly report is due within 30 days of the calendar quarter reporting period. **(R 336.2170)**

6. Quarterly reporting of excess opacity emissions (including the nature and cause of the periods of excess emissions), and of the dates and times of the monitoring systems being inoperative. Each quarterly report is due within 30 days of the calendar quarter reporting period. **(R 336.2170)**

See Appendix 8

VIII. STACK/VENT RESTRICTION(S)

The exhaust gases from the stacks listed in the table below shall be discharged unobstructed vertically upwards to the ambient air unless otherwise noted:

Stack & Vent ID	Maximum Exhaust Dimensions (inches)	Minimum Height Above Ground (feet)	Underlying Applicable Requirements
1. SVBLR3	327[2]	642[2]	**R 336.1201(3)**

IX. OTHER REQUIREMENT(S)

1. The permittee shall comply with the acid rain permitting provisions of 40 CFR 72.1 to 72.94, as outlined in a complete Phase II, Acid Rain Permit issued by the AQD. Phase II, Acid Rain Permit No. MI-AR-1710-2020 is hereby incorporated into this ROP as Appendix 9. **(R 336.1902(1)(q))**

2. The permittee shall not allow the emission of an air pollutant to exceed the amount of any emission allowances that an affected source lawfully holds as of the allowance transfer deadline pursuant to R 336.1902(1)(q) and 40 CFR 72.9(c)(1)(i). **(R 336.1213(10))**

3. The permittee shall comply with the provisions of the Cross-State Air Pollution Rule NO_X Annual Trading Program, as specified in 40 CFR Part 97, Subpart AAAAA, and identified in Appendix 10. **(40 CFR Part 97, Subpart AAAAA)**

4. The permittee shall comply with the provisions of the Cross-State Air Pollution Rule NO_X Ozone Season Group 2 Trading Program, as specified in 40 CFR Part 97, Subpart EEEEE, and identified in Appendix 10. **(40 CFR Part 97, Subpart EEEEE)**

5. The permittee shall comply with the provisions of the Cross-State Air Pollution Rule SO_2 Group 1 Trading Program, as specified in 40 CFR Part 97, Subpart CCCCC, and identified in Appendix 10. **(40 CFR Part 97, Subpart CCCCC)**

6. The permittee shall comply with applicable provisions of Act 451 Part 15 EMISSION LIMITATIONS AND PROHIBITIONS—MERCURY.[2] **(R 336.2503(1))**

7. The permittee shall comply with the applicable requirements of 40 CFR Part 63, Subpart UUUUU - National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-fired Electric Utility Steam Generating Units as specified in FGMATS_U3.[2] **(40 CFR Part 63, Subpart UUUUU)**

Footnotes:

[1]This condition is state only enforceable and was established pursuant to Rule 201(1)(b).

[2]This condition is federally enforceable and was established pursuant to Rule 201(1)(a).

[3]This condition is federally enforceable and was originally established in the consent decree settling, "U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" and also pursuant to Act 451, Section 324.5503(b), and will remain in effect after termination of the consent decree.

[4]Definitions specific to this condition may be found in Appendix 1-B: Definitions Applicable to Specified Permit Conditions.

EUCOALHAND
EMISSION UNIT CONDITIONS

DESCRIPTION

The coal handling facility consists of: (2) dumper buildings, transfer conveyors, transfer building, breaker house, bunker rooms, and the coal pile storage area itself.

Flexible Group ID: NA

POLLUTION CONTROL EQUIPMENT

Enclosures, 11 baghouses, dust suppression, telescopic spouts. The Dust Collectors serving the Unit 1 and 2 (DC10), and Unit 3 (DC1) dumper houses, and Coal yard dust hopper (DC11) are subject to 40 CFR Part 64 (CAM).

Dust collectors serving the breaker house (DC4), bunker houses (DC 5, 6, 7) and the reclaim hopper (DC9) are subject to the New Source Performance Standard 40 CFR Part 60, Subpart Y. (Initial performance testing has been completed.)

Dust collectors serving the reclaim (DC2) and transfer house (DC3A, DC3B) are subject to Michigan Rule 336.1301.

I. EMISSION LIMIT(S)

Pollutant	Limit	Time Period/ Operating Scenario	Equipment	Monitoring/ Testing Method	Underlying Applicable Requirements
1. PM	0.10 pound per 1,000 pounds exhaust gas, on a dry basis	At all times, as verifiable through any requested stack testing	Each discharge point	SC IV.1 SC VI.1 Through SC VI.8 (Proper maintenance and operation of the baghouses)	**R 336.1331(1)(a), Table 31(j)**
2. Opacity	20%	6-minute average	Discharge points for dust collectors DC4, DC5, DC6, DC7, and DC9	SC IV.1 SC VI.1 Through SC VI.8 (Proper maintenance and operation of the baghouses)	**40 CFR 60.252(c) (NSPS, Subpart Y)**
3. Opacity	20%	6-minute average	Discharge points for dust collectors DC1, DC2, DC3A, DC3B, DC10, and DC11,	SC IV.1 SC VI.1 Through SC VI.8 (Proper maintenance and operation of the baghouses)	**R 336.1301(1)(a)**

II. MATERIAL LIMIT(S)

NA

III. PROCESS/OPERATIONAL RESTRICTION(S)

1. The permittee shall not operate a process portion unless the particulate matter control device controlling the portion is installed and operating properly. **(R 336.1910)**

2. The permittee shall operate all coal handling equipment in accordance with the most recent facility Fugitive Dust Control Plan as approvable by the AQD District Supervisor. **(R 336.1213(3))**

3. The permittee shall not operate EUCOALHAND unless a malfunction abatement plan (MAP) as described in Rule 911(2), for emission control equipment is implemented and maintained. The MAP shall, at a minimum, specify the following:

   a. A complete preventative maintenance program including identification of the supervisory personnel responsible for overseeing the inspection, maintenance, and repair of air-cleaning devices, a description of the items or conditions that shall be inspected, the frequency of the inspections or repairs, and an identification of the major replacement parts that shall be maintained in inventory for quick replacement.

   b. An identification of the source and air-cleaning device operating variables that shall be monitored to detect a malfunction or failure, the normal operating range of these variables, and a description of the method of monitoring or surveillance procedures.

   c. A description of the corrective procedures or operational changes that shall be taken in the event of a malfunction or failure to achieve compliance with the applicable emission limits.

   If at any time the MAP fails to address or inadequately addresses an event that meets the characteristics of a malfunction, the permittee shall amend the MAP within 45 days after such an event occurs. The permittee shall also amend the MAP within 45 days if new equipment is installed or upon request from the District Supervisor. The permittee shall submit the MAP and any amendments to the MAP to the AQD District Supervisor for review and approval. If the AQD does not notify the permittee within 90 days of submittal, the MAP or amended MAP shall be considered approved. Until an amended plan is approved, the permittee shall implement corrective procedures or operational changes to achieve compliance with all applicable emission limits. **(R 336.1910, R 336.1911)**

IV. DESIGN/EQUIPMENT PARAMETER(S)

1. Each particulate matter control device shall be equipped with pressure drop measurement devices and associated alarm system.[2] **(R 336.1201(3), R 336.1213(3))**

V. TESTING/SAMPLING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. The permittee shall assess opacity using USEPA Reference Method 9 - “Visual Determination of the Opacity of Emissions from Stationary Sources”, upon the request of AQD. **(R 336.1213(3))**

2. Upon request of the AQD District Supervisor, the permittee shall verify PM emission rates from EUCOALHAND by testing at the owner’s expense, in accordance with the Department requirements. Testing shall be performed using an approved USEPA Method listed in 40 CFR Part 60, Appendix A; Part 10 of the Michigan Air Pollution Control Rules. An alternate method, or a modification to the approved USEPA Method, may be specified in an AQD-approved Test Protocol. No less than 30 days prior to testing, the permittee shall submit a complete test plan to the AQD Technical Programs Unit and District Office. The AQD must approve the final plan prior to testing, including any modifications to the method in the test protocol that are proposed after initial submittal. The permittee must submit a complete report of the test results to the AQD Technical Programs Unit and District Office within 60 days following the last date of the test. **(R 336.1213(3), R 336.2001, R 336.2003, R 336.2004)**

3. The permittee shall notify the AQD Technical Programs Unit Supervisor and the District Supervisor not less than 7 days of the time and place before performance tests are conducted. **(R 336.1213(3))**

See Appendix 5

VI. MONITORING/RECORDKEEPING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. The permittee shall conduct and record non-certified visible emissions observations for the dust collectors servicing EUBOILER 1, EUBOILER2 (DC10) and EUBOILER3 (DC1) dumper houses and Coal Yard dust hopper DC(11) once per day when operating, as the primary indicator of the proper functioning of each fabric filter dust collector. If visible emissions are observed, the permittee shall document the visible emissions, including the duration, and continue to observe the source of the visible emissions until no visible emissions are observed. The permittee shall initiate corrective actions as quickly as possible upon the detection of visible emissions. If there is a break in the visible emissions observations, it will be assumed that visible emissions continue to occur during any break in observations. The appropriate range of visible emissions defining proper functioning of each fabric filter dust collector is no visible emissions. **(40 CFR 64.6(c)(1)(i), (ii), and (iii))**

2. An excursion is the observation of visible emissions for the dust collectors serving EUBOILER1 and EUBOILER2 (DC10) or EUBOILER3 (DC1) dumper house or the coal yard dust hopper (DC11) for a duration exceeding one (1) hour. **(40 CFR 64.6(c)(2))**

3. The permittee shall properly maintain the monitoring system, including keeping necessary parts for routine repair of the monitoring equipment. **(40 CFR 64.7(b))**

4. Upon detecting an excursion or exceedance, the owner or operator shall restore operation of the pollutant-specific emissions unit (including the control device and associated capture system) to its normal or usual manner of operation as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions or other measures as specified in the MAP. The response shall include minimizing the period of any startup, shutdown or malfunction and taking any necessary corrective actions to restore normal operation and prevent the likely recurrence of the cause of an excursion or exceedance (other than those caused by excused startup or shutdown conditions). **(40 CFR 64.7(d))**

5. Except for, as applicable, monitoring malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), the owner or operator shall conduct all monitoring in continuous operation (or shall collect data at all required intervals) at all times that the pollutant-specific emissions unit is operating. Data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities shall not be used for purposes of this part, including data averages and calculations or fulfilling a minimum data availability requirement, if applicable. The owner or operator shall use all the data collected during all other periods in assessing the operation of the control device and associated control system. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions. **(40 CFR 64.6(c)(3), 40 CFR 64.7(c))**

6. Any formal compliance determinations with the opacity limit established in 40 CFR 60.252(c) shall utilize Method 9 and the procedures in 40 CFR 60.11. **(40 CFR 60.254(b)(2))**

7. The permittee shall maintain records of monitoring data, monitor performance data, corrective actions taken, any written quality improvement plan and any activities undertaken to implement a quality improvement plan, and other information such as data used to document the adequacy of monitoring, or records of monitoring maintenance or corrective actions. **(40 CFR 64.9(b)(1))**

8. The permittee shall perform, and document non-certified visible emissions observations from dust collectors DC4, DC5, DC6, DC7, and DC9 as required in I.2 on a daily basis when EUCOALHAND is operating. If during the observation there are any visible emissions detected from an emission point, then corrective procedures as defined in the MAP shall be implemented. Records of the non-certified visible emissions observations, USEPA Method 9 observations that are performed, the reason for any visible emissions observed, and any corrective actions taken, shall be kept on file and in a format acceptable to the AQD. **(R 336.1213(3))**

VII. REPORTING

1. Prompt reporting of deviations pursuant to General Conditions 21 and 22 of Part A. **(R 336.1213(3)(c)(ii))**

2. Semiannual reporting of monitoring and deviations pursuant to General Condition 23 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for reporting period July 1 to December 31 and September 15 for reporting period January 1 to June 30. **(R 336.1213(3)(c)(i))**

3. Annual certification of compliance pursuant to General Conditions 19 and 20 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for the previous calendar year. **(R 336.1213(4)(c))**

4. Each semiannual report of monitoring deviations shall include summary information on the number, duration, and cause of exceedances/excursions in the reporting period; and the corrective actions taken in response. If there were no excursions and/or exceedances in the reporting period, then this report shall include a statement that there were no excursions and/or exceedances. **(40 CFR 64.9(a)(2)(i))**

5. Each semiannual report of monitoring deviations shall include summary information on monitor downtime. If there were no periods of monitor downtime in the reporting period, then this report shall include a statement that there were no periods of monitor downtime. **(40 CFR 64.9(a)(2)(ii))**

6. Each semiannual report of monitoring deviations shall include a description of the actions taken to implement a Quality Improvement Plan (QIP) during the reporting period, if appropriate. If a QIP has been completed, the report shall include documentation that the QIP has been implemented, and a discussion pertaining to whether the QIP implementation has reduced the likelihood of excursions or exceedances. **(40 CFR 64.9(a)(2)(iii))**

7. The permittee shall submit any performance test reports, except for Method 9, to the AQD Technical Programs Unit and District Office, in a format approved by the AQD. **(R 336.1213(3)(c), R 336.2001(5))**

See Appendix 8

VIII. STACK/VENT RESTRICTION(S)

NA

IX. OTHER REQUIREMENT(S)

1. The permittee shall otherwise comply with the applicable requirements of 40 CFR Part 60 (“Standards of Performance for New Stationary Sources”), Subparts A (“General Provisions’) and Y (“Standards of Performance for Coal Preparation Plants”). **(40 CFR Part 60, Subparts A and Y)**

2. The permittee shall comply with all applicable requirements of 40 CFR Part 64. **(40 CFR Part 64)**

3. If the permittee identifies a failure to achieve compliance with an emission limitation or standard for which the approved monitoring did not provide an indication of an excursion or exceedance while providing valid data, or the results of compliance or performance testing document a need to modify the existing indicator ranges or designated conditions, the permittee shall promptly notify the AQD and if necessary, submit a proposed modification of the ROP and CAM Plan to address the necessary monitoring changes. Such a modification may include but is not limited to, reestablishing indicator ranges or designated conditions, modifying the frequency of conducting monitoring and collecting data, or the monitoring of additional parameters. **(40 CFR 64.7(e))**

Footnotes:
[1] This condition is state only enforceable and was established pursuant to Rule 201(1)(b).
[2] This condition is federally enforceable and was established pursuant to Rule 201(1)(a).

EUSDA_U3
EMISSION UNIT CONDITIONS

DESCRIPTION

Lime preparation operations for Boiler 3 that support the SDA including storage silos, vertical ball mills, and lime slurry transfer and product tanks.

SDA operations for Boiler 3 including lime slurry atomizer head tanks, recycle silos, recycle mix tanks, and recycle slurry storage tanks. The two recycle silos are subject to 40 CFR Part 64 Compliance Assurance Monitoring (CAM).

Flexible Group ID: NA

POLLUTION CONTROL EQUIPMENT

Silos are controlled by bin vent filters.
Ball mills emissions controlled by spray scrubbers (mill scrubbers).
Recycle mix tank emissions controlled by a spray scrubber.

I. EMISSION LIMIT(S)

Pollutant	Limit	Time Period/ Operating Scenario	Equipment	Monitoring/ Testing Method	Underlying Applicable Requirements
1. Opacity	5%[2]	6-Minute average	Each bin vent filter in EUSDA_U3	SC VI.1	**R 336.1301(1)(c)**
2. Opacity	5%[2]	6-Minute average	Each spray scrubber in EUSDA_U3	SC VI.1	**R 336.1301(1)(c)**
3. PM	0.004 gr / dscf of exhaust gases[2]	Hourly	Each bin vent filter in EUSDA_U3	SC III.2 SC IV.1 SC V.1	**R 336.1331(1)(c)**
4. PM	0.01 gr / dscf of exhaust gases[2]	Hourly	Each spray scrubber in EUSDA_U3	SC III.2 SC IV.1 SC V.1	**R 336.1331(1)(c)**
5. PM10	0.03 pph[2]	Hourly	Each of the following bin vent filter emission points: SVLSS-BV3A SVLSS-BV3B SVLSS-BV3C	SC III.2 SC IV.1 SC V.1	**R 336.2803** **R 336.2804**
6. PM2.5	0.03 pph[2]	Hourly	Each of the following bin vent filter emission points: SVLSS-BV3A SVLSS-BV3B SVLSS-BV3C	SC III.2 SC IV.1 SC V.1	**R 336.2803** **R 336.2804**
7. PM10	0.021 pph[2]	Hourly	Each of the following spray scrubber emission points: SVVM-SS3A SVVM-SS3B SVVM-SS3C	SC III.2 SC IV.1 SC V.1	**R 336.2803** **R 336.2804**

Pollutant	Limit	Time Period/ Operating Scenario	Equipment	Monitoring/ Testing Method	Underlying Applicable Requirements
8. PM2.5	0.021 pph[2]	Hourly	Each of the following spray scrubber emission points: SVVM-SS3A SVVM-SS3B SVVM-SS3C	SC III.2 SC.IV.1 SC V.1	**R 336.2803 R 336.2804**
9. PM10	0.02 pph[2]	Hourly	Each of the following bin vent filter emission points: SVRS-BV3A SVRS-BV3B (CAM Subject)	SC III.2 SC IV.1 SC V.1 SC VI.1 SC VI.2	**R 336.2803 R 336.2804**
10. PM2.5	0.02 pph[2]	Hourly	Each of the following bin vent filter emission points: SVRS-BV3A SVRS-BV3B (CAM Subject)	SC III.2 SC IV.1 SC V.1 SC VI.1 SC VI.2	**R 336.2803 R 336.2804**
11. PM10	0.024 pph[2]	Hourly	Each of the following spray scrubber emission points: SVMT-SS3A1 SVMT-SS3B1 SVMT-SS3A2 SVMT-SS3B2	SC III.2 SC IV.1 SC V.1	**R 336.2803 R 336.2804**
12. PM2.5	0.024 pph[2]	Hourly	Each of the following spray scrubber emission points: SVMT-SS3A1 SVMT-SS3B1 SVMT-SS3A2 SVMT-SS3B2	SC III.2 SC IV.1 SC V.1	**R 336.2803 R 336.2804**

II. MATERIAL LIMIT(S)

NA

III. PROCESS/OPERATIONAL RESTRICTION(S)

1. The Campbell Complex fugitive dust plan shall be updated as necessary and kept at the facility. If at any time the fugitive dust control program fails to address or inadequately addresses a dusting event, the permittee shall amend the fugitive dust control program within 45 days after such an event occurs. The permittee shall also amend the fugitive dust control program within 45 days, if new equipment is installed or upon request from the AQD District Supervisor. The permittee shall submit the fugitive dust control program and any amendments to the fugitive dust control program to the AQD District Supervisor for review and approval. If the AQD does not notify the permittee within 90 days of submittal, the fugitive dust control program or amended fugitive dust control program shall be considered approved. Until an amended plan is approved, the permittee shall implement corrective procedures or operational changes to achieve compliance with all applicable emission limits.[2] **(R 336.1372, R 336.2803, R 336.2804, Act 451, Section 324.5524)**

2. The permittee shall not operate EUSDA_U3 unless a malfunction abatement plan (MAP) as described in Rule 911(2), for operation of the process and emission control equipment, is implemented updated as necessary, and kept at the facility. If at any time the MAP fails to address or inadequately addresses an event that meets

the characteristics of a malfunction, the permittee shall amend the MAP within 45 days after such an event occurs. The permittee shall also amend the MAP within 45 days, if new equipment is installed or upon request from the AQD District Supervisor. The permittee shall submit the MAP and any amendments to the MAP to the AQD District Supervisor for review and approval. If the AQD does not notify the permittee within 90 days of submittal, the MAP or amended MAP shall be considered approved. Until an amended plan is approved, the permittee shall implement corrective procedures or operational changes to achieve compliance with all applicable emission limits.[2] **(R 336.1910, R 336.1911)**

IV. DESIGN/EQUIPMENT PARAMETER(S)

1. The permittee shall not operate any portion of EUSDA_U3 unless the associated enclosures, bin vent filters and spray scrubbers are installed, maintained and operated in a satisfactory manner. Satisfactory manner includes operating and maintaining each control device in accordance with an approved MAP for EUSDA_U3 as required in SC III.2.[2] **(R 336.1910, R 336.1911, R 336.2803, R 336.2804)**

V. TESTING/SAMPLING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. Upon request of the AQD District Supervisor, the permittee shall verify PM, PM10, and PM2.5 emission rates from EUSDA_U3 by testing at owner's expense, in accordance with the Department requirements. Testing shall be performed using an approved USEPA Method listed in:

Pollutant	Test Method Reference
PM	40 CFR Part 60, Appendix A; Part 10 of the Michigan Air Pollution Control Rules
PM10/PM2.5	40 CFR Part 51, Appendix M

An alternate method, or a modification to the approved USEPA Method, may be specified in an AQD-approved Test Protocol. No less than 30 days prior to testing, the permittee shall submit a complete test plan to the AQD Technical Programs Unit and District Office. The AQD must approve the final plan prior to testing, including any modifications to the method in the test protocol that are proposed after initial submittal. The permittee must submit a complete report of the test results to the AQD Technical Programs Unit and District Office within 60 days following the last date of the test. **(R 336.1213(3), R 336.2001, R 336.2003, R 336.2004)**

The permittee shall notify the AQD Technical Programs Unit Supervisor and the District Supervisor not less than 7 days of the time and place before performance tests are conducted. **(R 336.1213(3))**

VI. MONITORING/RECORDKEEPING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. The permittee shall perform, and document non-certified visible emissions observations as required in SC I.1 and I.2 on a daily basis when EUSDA_U3 is operating. If during the observation there are any visible emissions detected from an emission point, then corrective procedures as defined in the MAP shall be implemented. Records of the non-certified visible emissions observations, USEPA Method 9 observations that are performed, the reason for any visible emissions observed, and any corrective actions taken, shall be kept on file and in a format acceptable to the AQD.[2] **(R 336.1301(1)(c)**

2. The permittee shall conduct and record non-certified visible emissions observations the Recycle Silo bin vent filters (SVRS-BV3A, SVRS-BV3B) once per day when operating, as the primary indicator of the proper functioning of each bin vent filter for EUSDA_U3. If visible emissions are observed, the permittee shall document the visible emissions, including duration, and continue to observe the source of the visible emissions until no visible emissions are observed. The permittee shall initiate corrective actions as quickly as possible upon the detection of visible emissions. If there is a break in the visible emissions observations, it will be assumed that visible emissions continue to occur during any break in observations. The appropriate range of visible emissions defining proper functioning of each bin vent filter is no visible emissions. **(40 CFR 64.6(c)(1)(i), (ii), and (iii))**

3. An excursion is the observation of visible emissions for a duration exceeding one (1) hour. **(40 CFR 64.6(c)(2))**

4. Upon detecting an excursion or exceedance, the owner or operator shall restore operation of the pollutant-specific emissions unit (including the control device and associated capture system) to its normal or usual manner of operation as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions or in accordance with the MAP. The response shall include minimizing the period of any startup, shutdown or malfunction and taking any necessary corrective actions to restore normal operation and prevent the likely recurrence of the cause of an excursion or exceedance (other than those caused by excused startup or shutdown conditions). **(40 CFR 64.7(d))**

5. Except for, as applicable, monitoring malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), the owner or operator shall conduct all monitoring in continuous operation (or shall collect data at all required intervals) at all times that the pollutant-specific emissions unit is operating. Data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities shall not be used for purposes of this part, including data averages and calculations or fulfilling a minimum data availability requirement, if applicable. The owner or operator shall use all the data collected during all other periods in assessing the operation of the control device and associated control system. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions. **(40 CFR 64.6(c)(3), 40 CFR 64.7(c))**

6. The permittee shall properly maintain the monitoring system, including keeping necessary parts for routine repair of the monitoring equipment. **(40 CFR 64.7(b))**

7. The permittee shall maintain records of monitoring data, monitor performance data, corrective actions taken, any written quality improvement plan and any activities undertaken to implement a quality improvement plan, and other information such as data used to document the adequacy of monitoring, or records of monitoring maintenance or corrective actions. **(40 CFR 64.9(b)(1))**

VII. REPORTING

1. Prompt reporting of deviations pursuant to General Conditions 21 and 22 of Part A. **(R 336.1213(3)(c)(ii))**

2. Semiannual reporting of monitoring and deviations pursuant to General Condition 23 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for reporting period July 1 to December 31 and September 15 for reporting period January 1 to June 30. **(R 336.1213(3)(c)(i))**

2. Annual certification of compliance pursuant to General Conditions 19 and 20 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for the previous calendar year. **(R 336.1213(4)(c))**

3. Each semiannual report of monitoring and deviations shall include summary information on the number, duration and cause of excursions and/or exceedances and the corrective actions taken. If there were no excursions and/or exceedances in the reporting period, then this report shall include a statement that there were no excursions and/or exceedances. **(40 CFR 64.9(a)(2)(i))**

4. Each semiannual report of monitoring and deviations shall include summary information on monitor downtime. If there were no periods of monitor downtime in the reporting period, then this report shall include a statement that there were no periods of monitor downtime. **(40 CFR 64.9(a)(2)(ii))**

5. Each semiannual report shall include a Quality Improvement Plan (QIP) during the reporting period, if appropriate. If a QIP has been completed, the report shall include documentation that the QIP has been implemented, and a discussion pertaining to whether the QIP implementation has reduced the likelihood of excursions or exceedances. **(40 CFR 64.9(a)(2)(iii))**

See Appendix 8

VIII. STACK/VENT RESTRICTION(S)

The exhaust gases from the stacks listed in the table below shall be discharged unobstructed vertically upwards to the ambient air unless otherwise noted:

Stack & Vent ID	Maximum Exhaust Dimensions (inches)	Minimum Height Above Ground (feet)	Underlying Applicable Requirements
1. SVLSS-BV3A	4.3[2]	135[2]	**R 336.2803** **R 336.2804**
2. SVLSS-BV3B	4.3[2]	135[2]	**R 336.2803** **R 336.2804**
3. SVLSS-BV3C	4.3[2]	135[2]	**R 336.2803** **R 336.2804**
4. SVVM-SS3A	11.4[2]	52[2]	**R 336.2803** **R 336.2804**
5. SVVM-SS3B	11.4[2]	52[2]	**R 336.2803** **R 336.2804**
6. SVVM-SS3C	11.4[2]	52[2]	**R 336.2803** **R 336.2804**
7. SVRS-BV3A	6.1[2]	126[2]	**R 336.2803** **R 336.2804**
8. SVRS-BV3B	6.1[2]	126[2]	**R 336.2803** **R 336.2804**
9. SVMT-SS3A1	6.1[2]	58[2]	**R 336.2803** **R 336.2804**
10. SVMT-SS3B1	6.1[2]	58[2]	**R 336.2803** **R 336.2804**
11. SVMT-SS3A2	6.1[2]	58[2]	**R 336.2803** **R 336.2804**
12. SVMT-SS3B2	6.1[2]	58[2]	**R 336.2803** **R 336.2804**

IX. OTHER REQUIREMENT(S)

1. The permittee shall comply with all applicable requirements of 40 CFR Part 64. **(40 CFR Part 64)**

2. If the permittee identifies a failure to achieve compliance with an emission limitation or standard for which the approved monitoring did not provide an indication of an excursion or exceedance while providing valid data, or the results of compliance or performance testing document a need to modify the existing indicator ranges or designated conditions, the permittee shall promptly notify the AQD and if necessary, submit a proposed modification of the ROP and CAM Plan to address the necessary monitoring changes. Such a modification may include but is not limited to, reestablishing indicator ranges or designated conditions, modifying the frequency of conducting monitoring and collecting data, or the monitoring of additional parameters. **(40 CFR 64.7(e))**

Footnotes:
[1] This condition is state only enforceable and was established pursuant to Rule 201(1)(b).
[2] This condition is federally enforceable and was established pursuant to Rule 201(1)(a).

EUDSI_U12
EMISSION UNIT CONDITIONS

DESCRIPTION

Dry Sorbent Injection (DSI) Material Handling for Boilers 1 and 2. Includes sorbent silos (hydrated lime or other sorbent) and pneumatic transfer.

Flexible Group ID: NA

POLLUTION CONTROL EQUIPMENT

Bin vent filters

I. EMISSION LIMIT(S)

Pollutant	Limit	Time Period/ Operating Scenario	Equipment	Monitoring/ Testing Method	Underlying Applicable Requirements
1. Opacity	5%[2]	6- Minute Average	Each bin vent filter in EUDSI_U12	SC VI.1	**R 336.1301(1)(c)**
2. PM	0.004 gr / dscf of exhaust gases[2]	Hourly	Each bin vent filter in EUDSI_U12	SC III.2 SC VI.1	**R 336.1331(1)(c)**
3. PM10	0.08 pph[2]	Hourly	Each of the following bin vent filter emission points: SVLSS-BV1A SVLSS-BV1B SVLSS-BV1C SVLSS-BV2A SVLSS-BV2B SVLSS-BV2C	SC III.2 SC VI.1	**R 336.2803** **R 336.2804**
4. PM2.5	0.08 pph[2]	Hourly	Each of the following bin vent filter emission points: SVLSS-BV1A SVLSS-BV1B SVLSS-BV1C SVLSS-BV2A SVLSS-BV2B SVLSS-BV2C	SC III.2 SC VI.1	**R 336.2803** **R 336.2804**

II. MATERIAL LIMIT(S)

NA

III. PROCESS/OPERATIONAL RESTRICTION(S)

1. The Campbell Complex fugitive dust plan shall be updated as necessary and kept at the facility. If at any time the fugitive dust control program fails to address or inadequately addresses a dusting event, the permittee shall amend the fugitive dust control program within 45 days after such an event occurs. The permittee shall also amend the fugitive dust control program within 45 days, if new equipment is installed or upon request from the AQD District Supervisor. The permittee shall submit the fugitive dust control program and any amendments to the fugitive dust control program to the AQD District Supervisor for review and approval. If the AQD does not

notify the permittee within 90 days of submittal, the fugitive dust control program or amended fugitive dust control program shall be considered approved. Until an amended plan is approved, the permittee shall implement corrective procedures or operational changes to achieve compliance with all applicable emission limits.[2] **(R 336.1372, R 336.2803, R 336.2804, Act 451, Section 324.5524)**

2. The permittee shall not operate EUDSI_U12 unless a malfunction abatement plan (MAP) as described in Rule 911(2), for operation of the process and emission control equipment, is implemented updated as necessary, and kept at the facility. If at any time the MAP fails to address or inadequately addresses an event that meets the characteristics of a malfunction, the permittee shall amend the MAP within 45 days after such an event occurs. The permittee shall also amend the MAP within 45 days, if new equipment is installed or upon request from the AQD District Supervisor. The permittee shall submit the MAP and any amendments to the MAP to the AQD District Supervisor for review and approval. If the AQD does not notify the permittee within 90 days of submittal, the MAP or amended MAP shall be considered approved. Until an amended plan is approved, the permittee shall implement corrective procedures or operational changes to achieve compliance with all applicable emission limits.[2] **(R 336.1910, R 336.1911)**

IV. DESIGN/EQUIPMENT PARAMETER(S)

1. The permittee shall not operate any portion of EUDSI_U12 unless the associated enclosures and bin vent filters are installed, maintained and operated in a satisfactory manner. Satisfactory manner includes operating and maintaining each control device in accordance with an approved MAP for EUDSI_U12 as required in SC III.2.[2] **(R 336.1910, R 336.1911, R 336.2803, R 336.2804)**

V. TESTING/SAMPLING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

NA

VI. MONITORING/RECORDKEEPING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. The permittee shall perform, and document non-certified visible emissions observations as required in SC I.1 on a daily basis when EUDSI_U12 is operating. If during the observation there are any visible emissions detected from an emission point, then corrective procedures as defined in the MAP shall be implemented. Records of the non-certified visible emissions observations, USEPA Method 9 observations that are performed, the reason for any visible emissions observed, and any corrective actions taken, shall be kept on file and in a format acceptable to the AQD.[2] **(R 336.1301(1)(c))**

VII. REPORTING

1. Prompt reporting of deviations pursuant to General Conditions 21 and 22 of Part A. **(R 336.1213(3)(c)(ii))**

2. Semiannual reporting of monitoring and deviations pursuant to General Condition 23 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for reporting period July 1 to December 31 and September 15 for reporting period January 1 to June 30. **(R 336.1213(3)(c)(i))**

3. Annual certification of compliance pursuant to General Conditions 19 and 20 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for the previous calendar year. **(R 336.1213(4)(c))**

4. The permittee shall submit any performance test reports to the AQD Technical Programs Unit and District Office, in a format approved by the AQD. **(R 336.1213(3)(c), R 336.2001(5))**

See Appendix 8

VIII. STACK/VENT RESTRICTION(S)

The exhaust gases from the stacks listed in the table below shall be discharged unobstructed vertically upwards to the ambient air unless otherwise noted:

Stack & Vent ID	Maximum Exhaust Dimensions (inches)	Minimum Height Above Ground (feet)	Underlying Applicable Requirements
1. SVLSS-BV1A	14[2]	140[2]	**R 336.2803** **R 336.2804**
2. SVLSS-BV1B	14[2]	140[2]	**R 336.2803** **R 336.2804**
3. SVLSS-BV1C	14[2]	140[2]	**R 336.2803** **R 336.2804**
4. SVLSS-BV2A	14[2]	140[2]	**R 336.2803** **R 336.2804**
5. SVLSS-BV2B	14[2]	140[2]	**R 336.2803** **R 336.2804**
6. SVLSS-BV2C	14[2]	140[2]	**R 336.2803** **R 336.2804**

IX. OTHER REQUIREMENT(S)

NA

Footnotes:
[1] This condition is state only enforceable and was established pursuant to Rule 201(1)(b).
[2] This condition is federally enforceable and was established pursuant to Rule 201(1)(a).

EUACI_U123
EMISSION UNIT CONDITIONS

DESCRIPTION

Activated carbon (or other sorbent) material handling including four (4) silos for Boiler Units 1, 2, and 3.

Flexible Group ID: NA

POLLUTION CONTROL EQUIPMENT

Bin vent filters

I. EMISSION LIMIT(S)

Pollutant	Limit	Time Period/ Operating Scenario	Equipment	Monitoring/ Testing Method	Underlying Applicable Requirements
1. Opacity	5%[2]	6- Minute Average	Each bin vent filter in EUACI_U123	SC VI.1	**R 336.1301(1)(c)**
2. PM	0.004 gr / dscf of exhaust gases[2]	Hourly	Each bin vent filter in EUACI_U123	SC III.2 SC VI.1	**R 336.1331(1)(c)**
3. PM10	0.045 pph[2]	Hourly	Each of the following bin vent filter emission points: SVACI-BV1A SVACI-BV2A	SC III.2 SC VI.1	**R 336.2803** **R 336.2804**
4. PM2.5	0.045 pph[2]	Hourly	Each of the following bin vent filter emission points: SVACI-BV1A SVACI-BV2A	SC III.2 SC VI.1	**R 336.2803** **R 336.2804**
5. PM10	0.041 pph[2]	Hourly	Each of the following bin vent filter emission points: SVACI-BV3A SVACI-BV3B	SC III.2 SC VI.1	**R 336.2803** **R 336.2804**
6. PM2.5	0.041 pph[2]	Hourly	Each of the following bin vent filter emission points: SVACI-BV3A SVACI-BV3B	SC III.2 SC VI.1	**R 336.2803** **R 336.2804**

II. MATERIAL LIMIT(S)

NA

III. PROCESS/OPERATIONAL RESTRICTION(S)

1. The Campbell Complex fugitive dust plan shall be updated as necessary and kept at the facility. If at any time the fugitive dust control program fails to address or inadequately addresses a dusting event, the permittee shall amend the fugitive dust control program within 45 days after such an event occurs. The permittee shall also amend the fugitive dust control program within 45 days, if new equipment is installed or upon request from the

AQD District Supervisor. The permittee shall submit the fugitive dust control program and any amendments to the fugitive dust control program to the AQD District Supervisor for review and approval. If the AQD does not notify the permittee within 90 days of submittal, the fugitive dust control program or amended fugitive dust control program shall be considered approved. Until an amended plan is approved, the permittee shall implement corrective procedures or operational changes to achieve compliance with all applicable emission limits.[2] **(R 336.1372, R 336.2803, R 336.2804, Act 451, Section 324.5524)**

2. The permittee shall not operate EUACI_U123 unless a malfunction abatement plan (MAP) as described in Rule 911(2), for operation of the process and emission control equipment, is implemented updated as necessary, and kept at the facility. If at any time the MAP fails to address or inadequately addresses an event that meets the characteristics of a malfunction, the permittee shall amend the MAP within 45 days after such an event occurs. The permittee shall also amend the MAP within 45 days, if new equipment is installed or upon request from the AQD District Supervisor. The permittee shall submit the MAP and any amendments to the MAP to the AQD District Supervisor for review and approval. If the AQD does not notify the permittee within 90 days of submittal, the MAP or amended MAP shall be considered approved. Until an amended plan is approved, the permittee shall implement corrective procedures or operational changes to achieve compliance with all applicable emission limits.[2] **(R 336.1910, R 336.1911)**

IV. DESIGN/EQUIPMENT PARAMETER(S)

1. The permittee shall not operate any portion of EUACI_U123 unless the associated enclosures and bin vent filters are installed, maintained and operated in a satisfactory manner. Satisfactory manner includes operating and maintaining each control device in accordance with an approved MAP for EUACI_U123 as required in SC III.2.[2] **(R 336.1910, R 336.1911, R 336.2803, R 336.2804)**

V. TESTING/SAMPLING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

NA

VI. MONITORING/RECORDKEEPING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. The permittee shall perform, and document non-certified visible emissions observations as required in SC I.1 on a daily basis when EUACI_U123 is operating. If during the observation there are any visible emissions detected from an emission point, then corrective procedures as defined in the MAP shall be implemented. Records of the non-certified visible emissions observations, USEPA Method 9 observations that are performed, the reason for any visible emissions observed, and any corrective actions taken, shall be kept on file and in a format acceptable to the AQD.[2] **(R 336.1301(1)(c))**

VII. REPORTING

1. Prompt reporting of deviations pursuant to General Conditions 21 and 22 of Part A. **(R 336.1213(3)(c)(ii))**

2. Semiannual reporting of monitoring and deviations pursuant to General Condition 23 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for reporting period July 1 to December 31 and September 15 for reporting period January 1 to June 30. **(R 336.1213(3)(c)(i))**

3. Annual certification of compliance pursuant to General Conditions 19 and 20 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for the previous calendar year. **(R 336.1213(4)(c))**

See Appendix 8

VIII. STACK/VENT RESTRICTION(S)

The exhaust gases from the stacks listed in the table below shall be discharged unobstructed vertically upwards to the ambient air unless otherwise noted:

Stack & Vent ID	Maximum Exhaust Dimensions (inches)	Minimum Height Above Ground (feet)	Underlying Applicable Requirements
1. SVACI-BV1A	14[2]	60[2]	**R 336.2803** **R 336.2804**
2. SVACI-BV2A	14[2]	60[2]	**R 336.2803** **R 336.2804**
3. SVACI-BV3A	12[2]	80[2]	**R 336.2803** **R 336.2804**
4. SVACI-BV3B	12[2]	80[2]	**R 336.2803** **R 336.2804**

IX. OTHER REQUIREMENT(S)

NA

Footnotes:
[1] This condition is state only enforceable and was established pursuant to Rule 201(1)(b).
[2] This condition is federally enforceable and was established pursuant to Rule 201(1)(a).

EUBYPRODUCT
EMISSION UNIT CONDITIONS

DESCRIPTION

Flyash and byproduct handling system that transports flyash and byproduct from the plant to the disposal silos. The Unit 3 Transfer Tanks A and B (SVTT-BV3A and SVTT-BV3B) as well as Landfill Silo's A, B, and C (SVDCASS-BVA, SVDCASS-BVB, and SVDCASS-BVC) are subject to 40 CFR Part 64 (CAM).

Unit 3 System

- A large portion of PJFF flyash/byproduct is recycled back to the SDA via the SDA Recycle Flyash System and the remainder is conveyed to the Unit 3 Dry Flyash Byproduct System (for resale or landfill). The SDA Byproduct System consists of the following major equipment: two transfer towers [[TT3A and TT3B], three vacuum exhausters [two in operation and one spare], and three disposal silos [Flyash Silos A, B, and C]. Each transfer tower includes two filter separators (F/S) and a single transfer tank. Each transfer tank and each disposal silo are equipped with a bin vent filter. TT3A, TT3B and the three associated vacuum exhausters located at Boiler 3 are regulated under EUBYPRODUCT.

- The vacuum conveyance system pulls flyash from the PJFF hoppers and transports the flyash in hard piping through a F/S and into a transfer tank where the conveyance air is then discharged through a vacuum exhauster (two F/S's per transfer tank. Transfer tank displacement air is released through a bin vent filter to atmosphere. Flyash and byproduct materials collected in the transfer tanks are periodically conveyed to disposal silos A, B, or C where the material is loaded onto trucks for shipment as either byproduct or waste.

Unit 1 and 2 System

- The Dry Flyash Handling System services both Unit 1 and Unit 2 and consists of the following major equipment: three transfer towers [TT1, TT2 and TT3], five vacuum exhausters [three in operation and two spares], and two disposal silos [DSA, DSB]. Each transfer tower includes a filter separator and transfer tank. Each transfer tank and each disposal silo are equipped with a bin vent filter.

- TT1 and TT2 and the three associated vacuum exhausters located at Boiler 1&2 are regulated under EUBYPRODUCT. TT3 and the remaining two associated vacuum exhausters that solely support Unit 2 are not regulated by EUBYPRODUCT and are exempt from permitting under Michigan Rule 284(k).

- The vacuum conveyance system pulls flyash from each Boiler Unit's PJFF hoppers and transports the flyash in hard piping through a filter separator and into a transfer tank where the conveyance air is then discharged through a vacuum exhauster. The three vacuum exhausters that serve TT1 and TT2 normally discharge to the Unit 1 PJFF inlet ductwork. The two vacuum exhausters that serve TT3 can only discharge to the Unit 2 PJFF inlet duct. Transfer tank displacement air is released through a bin vent filter to atmosphere. Flyash and byproduct materials collected in the transfer tanks are periodically conveyed to disposal silos DSA and DSB where the material is loaded onto trucks for shipment as either byproduct or waste.

- When Boiler 1 and its associated PJFF are not in operation, then the vacuum exhausters associated with TT1 and TT2 will be redirected and one vacuum exhauster may intermittently discharge controlled emissions to atmosphere through a dedicated stack (bypassing the Boiler 1 PJFF). The operation of TT3 and its associated vacuum exhausters would remain unchanged; discharging into the Unit 2 inlet PJFF ductwork.

Common

- 3 Disposal Silos (A, B, & C) – located at the landfill, and store the byproduct/flyash until disposed in licensed landfill.
- Truck loading – each disposal silo has a loading bay under the silo where trucks are loaded with byproduct/flyash for transport to the landfill or for beneficial re-use. "B" silo also employs an exterior load-out chute.

Flexible Group ID: NA

POLLUTION CONTROL EQUIPMENT

Transfer tank: Each tank has as a filter separator that breaks the vacuum of the conveyance air to separate the transported material (the flyash byproduct) from the conveyance air. The filter separator is the fabric filter control for the conveyance air. The displacement air from the byproduct dropping into the tank is controlled by a bin vent filter.

Vacuum exhausters: Although the conveyance air from the vacuum exhausters are already controlled by the filter separator (with 0.004 gr/dscf PM emission guarantee), the normal vacuum exhauster discharge configuration is to the PJFF inlet breeching ducts (for either Unit 1, 2, or 3). There are limited times when the Unit 1 PJFF is offline for maintenance or other purposes, at which time the filter separator serving Unit 2 and/or in-plant dust systems will discharge to atmosphere through a vacuum exhauster. Emissions are still controlled via the filter separator (upgraded in PTI No. 18-15) and will be monitored through bag leak dust detectors and visible emission observations under this limited operating scenario.

Disposal Silos: The Disposal Silos A, B and C are controlled by bin vent filter dust collectors.

Truck Loading: Each disposal silo has a dust collector and/or dust suppressant system in the truck loading bay under the silos to control particulate matter during truck loading. The byproduct headed for landfill disposal is sufficiently wetted/conditioned through a pin-paddle mixer prior to loading and transport. The dry load-out chutes minimize fugitive emissions by proper seating of the telescopic chute to or over the truck hatch. Emissions during transfer activity are vacuumed to discharge back into the storage silo, which is controlled by the bin vent filters.

I. EMISSION LIMIT(S)

Pollutant	Limit	Time Period / Operating Scenario	Equipment	Monitoring/ Testing Method	Underlying Applicable Requirements
1. Opacity	5%[2]	6- Minute Average	Each of the following bin vent filter emission points: SVTT12-BV1 SVTT12-BV2 SVTT12-FSVE SVTT3-BV3A SVTT3-BV3B SVDCASS-BVA SVDCASS-BVB SVDCASS-BVC	SC VI.1 SC VI.2	**R 336.1301(1)(c)**
2. PM	0.004 gr / dscf of exhaust gases[2]	Hourly	Each of the following bin vent filter emission points: SVTT12-BV1 SVTT12-BV2 SVTT3-BV3A SVTT3-BV3B SVDCASS-BVA SVDCASS-BVB SVDCASS-BVC	SC III.2 SC VI.2	**R 336.1331(1)(c)**
3. PM	0.004 gr / dscf of exhaust gases[2]	Hourly	Byproduct transfer tank vacuum exhauster SVTT12-FSVE	SC III.2 SC VI.2	**R 336.1331(1)(c)**

Pollutant	Limit	Time Period / Operating Scenario	Equipment	Monitoring/ Testing Method	Underlying Applicable Requirements
4. PM10	0.03 pph^2	Hourly	Each of the following bin vent filter emission points: SVTT12-BV1 SVTT12-BV2	SC III.2 SC VI.2	**R 336.2803 R 336.2804**
5. PM2.5	0.03 pph^2	Hourly	Each of the following bin vent filter emission points: SVTT12-BV1 SVTT12-BV2	SC III.2 SC VI.2	**R 336.2803 R 336.2804**
6. PM10	0.05 pph^2	Hourly	Each of the following bin vent filter emission points: SVTT3-BV3A SVTT3-BV2B (CAM Subject)	SC III.2 SC VI.1 SC VI.2	**R 336.2803 R 336.2804**
7. PM2.5	0.05 pph^2	Hourly	Each of the following bin vent filter emission points: SVTT3-BV3A SVTT3-BV3B (CAM Subject)	SC III.2 SC VI.1 SC VI.2	**R 336.2803 R 336.2804**
8. PM10	0.55 pph^2	Hourly	Each of the following bin vent filter emission points: SVDCASS-BVA SVDCASS-BVB SVDCASS-BVC (CAM Subject)	SC III.2 SC VI.1 SC VI.2	**R 336.2803 R 336.2804**
9. PM2.5	0.55 pph^2	Hourly	Each of the following bin vent filter emission points: SVDCASS-BVA SVDCASS-BVB SVDCASS-BVC (CAM Subject)	SC III.2 SC VI.1 SC VI.2	**R 336.2803 R 336.2804**
10. PM10	0.10 pph^2	Hourly	Byproduct transfer tank vacuum exhauster: SVTT12-FSVE	SC III.2 SC VI.2	**40 CFR 52.21(c) and (d)**
11. PM2.5	0.10 pph^2	Hourly	Byproduct transfer tank vacuum exhauster: SVTT12-FSVE	SC III.2 SC VI.2	**40 CFR 52.21(c) and (d)**
12. PM	0.10 lbs per 1,000 lbs. exhaust gas	Hourly	Unit 2 dry flyash transfer tower – including the transfer tank, hoppers, and vacuum exhauster	SC III.2 SC VI.2	**R 336.1331**

II. MATERIAL LIMIT(S)

NA

III. PROCESS/OPERATIONAL RESTRICTION(S)

1. The Campbell Complex fugitive dust plan shall be updated as necessary and kept at the facility. If at any time the fugitive dust control program fails to address or inadequately addresses a dusting event, the permittee shall amend the fugitive dust control program within 45 days after such an event occurs. The permittee shall also amend the fugitive dust control program within 45 days, if new equipment is installed or upon request from the AQD District Supervisor. The permittee shall submit the fugitive dust control program and any amendments to the fugitive dust control program to the AQD District Supervisor for review and approval. If the AQD does not notify the permittee within 90 days of submittal, the fugitive dust control program or amended fugitive dust control program shall be considered approved. Until an amended plan is approved, the permittee shall implement corrective procedures or operational changes to achieve compliance with all applicable emission limits.[2] **(R 336.1372, R 336.2803, R 336.2804, Act 451, Section 324.5524)**

2. The permittee shall not operate EUBYPRODUCT unless a malfunction abatement plan (MAP) as described in Rule 911(2), for operation of the process and emission control equipment, is implemented updated as necessary, and kept at the facility. If at any time the MAP fails to address or inadequately addresses an event that meets the characteristics of a malfunction, the permittee shall amend the MAP within 45 days after such an event occurs. The permittee shall also amend the MAP within 45 days, if new equipment is installed or upon request from the AQD District Supervisor. The permittee shall submit the MAP and any amendments to the MAP to the AQD District Supervisor for review and approval. If the AQD does not notify the permittee within 90 days of submittal, the MAP or amended MAP shall be considered approved. Until an amended plan is approved, the permittee shall implement corrective procedures or operational changes to achieve compliance with all applicable emission limits.[2] **(R 336.1910, R 336.1911)**

IV. DESIGN/EQUIPMENT PARAMETER(S)

1. The permittee shall not operate any portion of EUBYPRODUCT unless the associated enclosures and bin vent filters and filter separators are installed, maintained and operated in a satisfactory manner. Satisfactory manner includes operating and maintaining each control device in accordance with an approved MAP for EUBYPRODUCT as required in SC III.2.[2] **(R 336.1910, R 336.1911, R 336.2803, R 336.2804)**

2. The permittee shall not operate each byproduct transfer tank vacuum exhauster unless the associated filter separator exhaust gases discharge to an associated PJFF baghouse on either EUBOILER1, EUBOILER2, or EUBOILER3, except as allowed in SC IV.3.[2] **(R 336.1205, R 336.1331, R 336.2803, R 336.2804)**

3. The exhaust from the filter/separator associated with EUBOILER2 shall be routed back to the PJFF for EUBOILER1, except at times when the PJFF for EUBOILER1 is not operating.[2] **(R 336.1205, R 336.1331, 40 CFR 52.21(c) and (d))**

V. TESTING/SAMPLING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

NA

VI. MONITORING/RECORDKEEPING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. The permittee shall perform, and document non-certified visible emissions observations on all exhausts to the atmosphere as required in SC I.1 on a daily basis when EUBYPRODUCT is operating. If during the observation there are any visible emissions detected from an emission point, then corrective procedures as defined in the MAP shall be implemented. Records of the non-certified visible emissions observations, USEPA Method 9

observations that are performed, the reason for any visible emissions observed, and any corrective actions taken, shall be kept on file and in a format acceptable to the AQD.[2] **(R 336.1301(1)(c))**

2. The permittee shall conduct and record non-certified visible emissions observations from the bin vent filters servicing the EUBOILER3 Transfer Tanks (SVTT-BV3A, SVTT-BV3B) and the Landfill Silos (SVDCASS-BVA, SVDCASS-BVB, and SVCASSS-BVC) once per day when operating, as the primary indicator of the proper functioning of each bin vent filter for EUBYPRODUCT. If visible emissions are observed, the permittee shall document the visible emissions, including duration, and continue to observe the source of the visible emissions until no visible emissions are observed. The permittee shall initiate corrective actions as quickly as possible upon the detection of visible emissions. If there is a break in the visible emissions observations, it will be assumed that visible emissions continue to occur during any break in observations. The appropriate range of visible emissions defining proper functioning of each bin vent filter is no visible emissions. **(40 CFR 64.6(c)(1)(i), (ii), and (iii))**

3. The permittee shall utilize visible emissions as the primary indicator of the proper functioning of each PM control device. The appropriate range of visible emissions defining proper functioning of the PM Control Device is no visible emissions.[2] **(R 336.1201(3), 40 CFR 64.6(c)(1)(i) and (ii))**

4. The permittee shall keep, in a satisfactory manner, all records necessary to show that the Campbell Complex fugitive dust plan required by SC III.1 is being implemented.[2] **(R 336.1372, R 336.2803, R 336.2804, Act 451, Section 324.5524)**

5. The permittee shall keep, in a satisfactory manner, all records necessary to show that the MAP required by SC III.2 is being implemented.[2] **(R 336.1910, R 336.1911)**

6. The permittee shall keep, in a satisfactory manner, visible emissions records for the times that the filter/separator associated with EUBOILER2 is routed to SVTT12-FSVE instead of the PJFF for EUBOILER1.[2] **(R 336.1205, R 336.1331, 40 CFR 52.21(c) and (d), R 336.1213(3))**

7. The permittee shall restore operation of the emission unit, control device, and associated pollutant capture system equipment to normal/compliant operation as quickly as possible in response to any noted exceedance or excursion. **(40 CFR 64.7(d))**

8. Upon detecting an excursion or exceedance, the owner or operator shall restore operation of the pollutant-specific emissions unit (including the control device and associated capture system) to its normal or usual manner of operation as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions or as specified by the MAP. The response shall include minimizing the period of any startup, shutdown or malfunction and taking any necessary corrective actions to restore normal operation and prevent the likely recurrence of the cause of an excursion or exceedance (other than those caused by excused startup or shutdown conditions). **(40 CFR 64.7(d))**

9. Except for, as applicable, monitoring malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), the owner or operator shall conduct all monitoring in continuous operation (or shall collect data at all required intervals) at all times that the pollutant-specific emissions unit is operating. Data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities shall not be used for purposes of this part, including data averages and calculations or fulfilling a minimum data availability requirement, if applicable. The owner or operator shall use all the data collected during all other periods in assessing the operation of the control device and associated control system. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions. **(40 CFR 64.6(c)(3), 40 CFR 64.7(c))**

10. The permittee shall properly maintain the monitoring system, including keeping necessary parts for routine repair of the monitoring equipment. **(40 CFR 64.7(b))**

11. The permittee shall maintain records of monitoring data, monitor performance data, corrective actions taken, any written quality improvement plan and any activities undertaken to implement a quality improvement plan, and

other information such as data used to document the adequacy of monitoring, or records of monitoring maintenance or corrective actions. **(40 CFR 64.9(b)(1))**

VII. REPORTING

1. Prompt reporting of deviations pursuant to General Conditions 21 and 22 of Part A. **(R 336.1213(3)(c)(ii))**

2. Semiannual reporting of monitoring and deviations pursuant to General Condition 23 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for reporting period July 1 to December 31 and September 15 for reporting period January 1 to June 30. **(R 336.1213(3)(c)(i))**

3. Annual certification of compliance pursuant to General Conditions 19 and 20 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for the previous calendar year. **(R 336.1213(4)(c))**

4. Each semiannual report of monitoring and deviations shall include summary information on the number, duration and cause of excursions and/or exceedances and the corrective actions taken. If there were no excursions and/or exceedances in the reporting period, then this report shall include a statement that there were no excursions and/or exceedances. **(40 CFR 64.9(a)(2)(i))**

5. Each semiannual report shall include a Quality Improvement Plan (QIP) during the reporting period, if appropriate. If a QIP has been completed, the report shall include documentation that the QIP has been implemented, and a discussion pertaining to whether the QIP implementation has reduced the likelihood of excursions or exceedances. **(40 CFR 64.9(a)(2)(iii))**

See Appendix 8

VIII. STACK/VENT RESTRICTION(S)

The exhaust gases from the stacks listed in the table below shall be discharged unobstructed vertically upwards to the ambient air unless otherwise noted:

Stack and Vent ID	Maximum Exhaust Diameter/Dimensions (inches)	Minimum Height Above Ground (feet)	Underlying Applicable Requirements
1. SVTT12-BV1	9^2	32^2	**R 336.2803** **R 336.2804**
2. SVTT12-BV2	9^2	32^2	**R 336.2803** **R 336.2804**
3. SVTT12-FSVE	20^2	40^2	**R 336.2803** **R 336.2804**
4. SVTT3-BV3A	14^2	70^2	**R 336.2803** **R 336.2804**
5. SVTT3-BV3B	14^2	70^2	**R 336.2803** **R 336.2804**
6. SVDCASS-BVA	$24x60^2$	141^2	**R 336.2803** **R 336.2804**
7. SVDCASS-BVB	$24x60^2$	141^2	**R 336.2803** **R 336.2804**
8. SVDCASS-BVC	$24x60^2$	136^2	**R 336.2803** **R 336.2804**
9. SVBLR12	228^2	400^2	**R 336.2803** **R 336.2804**
10. SVBLR3	327^2	642^2	**R 336.2803** **R 336.2804**

IX. OTHER REQUIREMENT(S)

1. The permittee shall comply with all applicable requirements of 40 CFR Part 64. **(40 CFR Part 64)**

2. If the permittee identifies a failure to achieve compliance with an emission limitation or standard for which the approved monitoring did not provide an indication of an excursion or exceedance while providing valid data, or the results of compliance or performance testing document a need to modify the existing indicator ranges or designated conditions, the permittee shall promptly notify the AQD and if necessary, submit a proposed modification of the ROP and CAM Plan to address the necessary monitoring changes. Such a modification may include but is not limited to, reestablishing indicator ranges or designated conditions, modifying the frequency of conducting monitoring and collecting data, or the monitoring of additional parameters. **(40 CFR 64.7(e))**

Footnotes:
[1] This condition is state only enforceable and was established pursuant to Rule 201(1)(b).
[2] This condition is federally enforceable and was established pursuant to Rule 201(1)(a).

EUAUXBLR12
EMISSION UNIT CONDITIONS

DESCRIPTION

The common auxiliary boiler for Units 1 and 2 is an oil-fired fire-tube boiler rated at 17 MMBTU/hr. This boiler is a limited use boiler, which is defined in 40 CFR 63.7575 as any boiler that burns any amount of solid, liquid, or gaseous fuels and has a federally enforceable average annual capacity factor of no more than 10%. This unit is subject to the provisions of 40 CFR Part 63, Subpart DDDDD.

Flexible Group ID: NA

POLLUTION CONTROL EQUIPMENT

NA

I. EMISSION LIMIT(S)

NA

II. MATERIAL LIMIT(S)

Material	Limit	Time Period/ Operating Scenario	Equipment	Monitoring/ Testing Method	Underlying Applicable Requirements
1. Fuel Oil	0.5% sulfur by weight based on a higher heating value of 18,000 BTU/lb[2]	Applicable at all times	EUAUXBLR12	SC VI.1	**R 336.1401(1), Table 41**
2. #2 Fuel Oil (Note A)	10% annual capacity factor of oil (Note B)[2]	Calendar Year	EUAUXBLR12	SC VI.4	**40 CFR 63.7555(a)(3)**

Note A: This limit is to satisfy the Federally Enforceable capacity factor limit associated with the limited use definition under 40 CFR Part 63, Subpart DDDDD, 40 CFR 63.7575.

Note B: Annual capacity factor means the ratio between the actual heat input to a boiler from the fuels burned during a calendar year to the potential heat input to the boiler had it been operated for 8,760 hours during a year at the maximum steady state design heat input capacity. (40 CFR 63.7575)

3. The permittee shall only burn fuels as allowed in the Unit designed to burn gas under light liquid subcategory definition in 40 CFR 63.7575. **(40 CFR 63.7575, R336.1213(3))**

III. PROCESS/OPERATIONAL RESTRICTION(S)

1. To demonstrate continuous compliance, the permittee shall conduct a tune-up of the boiler every 5 years (within 61 months) of the date of the last tune up. If the boiler is not operating on the required date for tune-up, the tune-up must be conducted within 30 calendar days of startup.[2] **(40 CFR 63.7500(a), 40 CFR 63.7515(d), 40 CFR 63.7540(12) and (13))**

2. The permittee shall conduct tune up of the boiler as specified in the following:[2] **(40 CFR 63.7540(a)(12))**

   a. As applicable, inspect the burner, and clean or replace any components of the burner as necessary (the permittee may delay the burner inspection until the next unit shutdown).

   b. Inspect the flame pattern, as applicable, and adjust the burner as necessary to optimize the flame pattern.

c. Inspect the system controlling the air-to-fuel ratio, as applicable, and ensure that it is correctly calibrated and functioning properly (the permittee may delay the inspection until the next unit shutdown).

d. Optimize total emissions of CO.

e. Measure the concentrations in the effluent stream of CO in parts per million, by volume, and oxygen in volume percent, before and after the adjustments are made.

f. Maintain on-site and submit, if requested by the Administrator, a report containing the information below:
   i. The concentrations of CO in the effluent stream in parts per million by volume, and oxygen content in volume percent, measured at high fire or typical operating load, before and after the tune-up of the boiler or process heater.
   ii. A description of any corrective actions taken as part of the tune-up.

3. At all times, the permittee must operate and maintain any affected source (as defined in 40 CFR 63.7490, stated in SC IX.1), including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator that may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source. **(40 CFR 63.700(a)(3))**

4. Limited-use boilers and process heaters must complete a tune-up every 5 years as specified in 40 CFR 63.7540. They are not subject to the emission limits in Tables 1 and 2 or 11 through 13 to this subpart, the annual tune-up, or the energy assessment requirements in Table 3 to this subpart, or the operating limits in Table 4 to this subpart. **(40 CFR 63.7500(c))**

5. The permittee shall install a fuel meter.[2] **(R 336.1201(3))**

IV. DESIGN/EQUIPMENT PARAMETER(S)

NA

V. TESTING/SAMPLING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

NA

VI. MONITORING/RECORDKEEPING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. The permittee shall maintain sufficient records to demonstrate that the sulfur content for each shipment of fuel oil received is less than 0.5% by weight.[2] **(R 336.1201(3))**

2. The permittee shall conduct and maintain records of a daily (non-certified) visual observation for opacity in order to verify proper firing, whenever a boiler is in use for 24 consecutive hours or more. **(R 336.1213(3))**

3. The permittee shall keep a record of the following on a monthly basis:[2] **(R 336.1201(3))**
   a. Total fuel usage
   b. Sulfur content of fuel oil
   c. Higher Heating Value of fuel oil

4. The permittee shall keep fuel use records for the days the boiler was operating.[2] **(40 CFR 63.7525(k))**

5. The permittee shall maintain a complete record of fuel oil specifications and/or fuel analysis for each delivery, or storage tank, of fuel oil used for the auxiliary boiler. These records may include purchase records for ASTM specification fuel oil, specifications or analyses provided by the vendor at the time of delivery, analytical results from laboratory testing, or any other records adequate to demonstrate compliance with the percent sulfur limit in fuel oil.[2] **(R 336.1201(3))**

6. The permittee shall keep records of compliance demonstrations.[2] **(R°336.1201(3))**

7. For each unit that meets the definition of limited-use boiler or process heater, the permittee must keep fuel use records for the days the boiler or process heater was operating. **(40 CFR 63.7525(k))**

8. The permittee must keep records according to paragraphs (a)(1) and (2) of 40 CFR 63.7555. **(40 CFR 63.7555(a))**
   a. A copy of each notification and report that is submitted to comply with this subpart, including all documentation supporting any Initial Notification or Notification of Compliance Status or semiannual compliance report that permittee submitted, according to the requirements in 40 CFR Part 63.10(b)(2)(xiv). **(40 CFR 63.7555(a)(1))**
   b. Records of performance tests, fuel analyses, or other compliance demonstrations and performance evaluations as required in 40 CFR Part 63.10(b)(2)(viii). **(40 CFR 63.7555(a)(2))**

9. For units in the limited use subcategory, the permittee must keep a copy of the federally enforceable permit that limits the annual capacity factor to less than or equal to 10 percent and fuel use records for the days the boiler or process heater was operating. **(40 CFR 63.7555(a)(3))**

10. Records must be in a form suitable and readily available for expeditious review, according to 40 CFR 63.10(b)(1). **(40 CFR 63.7560(a))**

11. As specified in 40 CFR 63.10(b)(1), the permittee must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record. **(40 CFR 63.7560(b))**

12. The permittee must keep each record on site, or they must be accessible from on-site (for example, through a computer network), for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to 40 CFR 63.10(b)(1). The permittee can keep the records off site for the remaining 3 years. **(40 CFR 63.7560(c))**

See Appendix 3-C (Fuel Oil Sulfur Monitoring)

VII. REPORTING

1. Prompt reporting of deviations pursuant to General Conditions 21 and 22 of Part A. **(R 336.1213(3)(c)(ii))**

2. Semiannual reporting of monitoring and deviations pursuant to General Condition 23 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for reporting period July 1 to December 31 and September 15 for reporting period January 1 to June 30. **(R 336.1213(3)(c)(i))**

3. Annual certification of compliance pursuant to General Conditions 19 and 20 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for the previous calendar year. **(R 336.1213(4)(c))**
4. The permittee must meet the notification requirements in 40 CFR 63.7545 according to the schedule in 40 CFR 63.7545 and in Subpart A of 40 CFR Part 63. **(40 CFR 63.7495(d))**

5. The permittee must submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in 40 CFR 63.7545(e). **(40 CFR 63.7530(f))**

6. The permittee must submit to the Administrator all of the notifications in 40 CFR 63.7(b) and (c); 40 CFR 63.8(e), (f)(4) and (6); and 40 CFR 63.9(b) through (h) that apply by the dates specified. **(40 CFR 63.7545(a))**

7. Unless the USEPA Administrator has approved a different schedule for submission of reports under 40 CFR Part 63.10(a), the permittee must submit each report, according to paragraph (h) of 40 CFR 63.7550, by the date in Table 9 to this subpart and according to the requirements in paragraphs (b)(1) through (4) of 40 CFR 63.7550 as stated below. **(40 CFR 63.7550(b))**

a. Each semi-annual compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31. Annual, biennial, and 5-year compliance reports must cover the applicable 1-, 2-, or 5-year periods from January 1 to December 31. **(40 CFR 63.7550(b)(3))**

b. Each semi-annual compliance report must be postmarked or submitted no later than September 15 or March 15, whichever date is the first date following the end of the semiannual reporting period. Annual, biennial, and 5-year compliance reports must be postmarked or submitted no later than March 15. **(40 CFR 63.7550(b)(4), 40 CFR 63.7550(b)(5))**

8. A compliance report must contain the information below depending on how the facility chooses to comply with the limits set in this rule. **(40 CFR 63.7550(c))**
   a. If the facility is subject to the requirements of a tune-up, permittee must submit a compliance report with the information in paragraphs (c)(5)(i) through (iii), (xiv) and (xvii) of 40 CFR 63.7550, and paragraph (c)(5)(iv) of 40 CFR 63.7550 for limited-use boiler or process heater. **(40 CFR 63.7550(c)(1))**
   b. 40 CFR 63.7550(c)(5) is as follows:
      i. Company and Facility name and address. **(40 CFR 63.7550(c)(5)(i))**
      ii. Process unit information, emissions limitations, and operating parameter limitations. **(40 CFR 63.7550(c)(5)(ii))**
      iii. Date of report and beginning and ending dates of the reporting period. **(40 CFR 63.7550(c)(5)(iii))**
      iv. The total operating time during the reporting period. **(40 CFR 63.7550(c)(5)(iv))**
      v. Include the date of the most recent tune-up for each unit subject to only the requirement to conduct a 5-year tune-up according to 40 CFR 63.7540(a)(12). Include the date of the most recent burner inspection if it was not done annually, biennially, or on a 5-year period and was delayed until the next scheduled or unscheduled unit shutdown. **(40 CFR 63.7550(c)(5)(xiv))**
      vi. Statement by a responsible official with that official's name, title, and signature, certifying the truth, accuracy, and completeness of the content of the report. **(40 CFR 63.7550(c)(5)(xvii))**

9. The permittee must submit all reports required by Table 9 of 40 CFR Part 63, Subpart DDDDD electronically to the USEPA via the Compliance and Emissions Data Reporting Interface (CEDRI). (CEDRI can be accessed through the USEPA's CDX.) The permittee must use the appropriate electronic report in CEDRI for 40 CFR Part 63, Subpart DDDDD. Instead of using the electronic report in CEDRI for 40 CFR Part 63, Subpart DDDDD, the permittee may submit an alternate electronic file consistent with the XML schema listed on the CEDRI Web site (*http://www.epa.gov/ttn/chief/cedri/index.html*), once the XML schema is available. If the reporting form specific to 40 CFR Part 63, Subpart DDDDD is not available in CEDRI at the time that the report is due, the permittee must submit the report to the Administrator at the appropriate address listed in 40 CFR 63.13. The permittee must begin submitting reports via CEDRI no later than 90-days after the form becomes available in CEDRI. **(40 CFR 63.7550(h)(3))**

See Appendix 8

VIII. STACK/VENT RESTRICTION(S)

The exhaust gases from the stacks listed in the table below shall be discharged unobstructed vertically upwards to the ambient air unless otherwise noted:

Stack & Vent ID	Maximum Exhaust Dimensions (inches)	Minimum Height Above Ground (feet)	Underlying Applicable Requirements
1. SVAUXBLR12	30[2]	153[2]	NA

IX. OTHER REQUIREMENT(S)

1. 40 CFR Part 63, Subpart DDDDD applies to new or reconstructed affected sources as described in paragraph (a)(2) of 40 CFR 63.7490, as listed below. **(40 CFR 63.7490(a))**
   a. The affected source of 40 CFR Part 63, Subpart DDDDD is each new or reconstructed industrial, commercial, or institutional boiler or process heater, as defined in 40 CFR 63.7575, located at a major source. **(40 CFR 63.7490(a)(2))**

2. A boiler or process heater is:
   a. New if the permittee commences construction of the boiler or process heater after June 4, 2010, and the permittee meets the applicability criteria at the time the permittee commences construction. **(40 CFR 63.7490(b))**
   b. Reconstructed if the permittee meets the reconstruction criteria as defined in 40 CFR 63.2, the permittee commences reconstruction after June 4, 2010, and the permittee meets the applicability criteria at the time the permittee commence reconstruction. **(40 CFR 63.7490(c))**
3. For affected sources (as defined in 40 CFR 63.7490) that have not operated since the previous compliance demonstration and more than one year has passed since the previous compliance demonstration, you must complete the subsequent compliance demonstration no later than 180 days after the re-start of the affected source and according to the applicable provisions in 40 CFR 63.7(a)(2) as cited in Table 10 to 40 CFR Part 63, Subpart DDDDD. You must complete a subsequent tune-up by following the procedures described in 40 CFR 63.7540(a)(10)(i) through (vi) and within 30 calendar days of startup for units that are not operating at the time of their scheduled tune-up. **(40 CFR 63.7515(g))**

4. The permittee shall comply with the General Provisions in 40 CFR 63.1 through 63.15 that apply to this source as indicated in Table 10 of 40 CFR Part 63, Subpart DDDDD. **(40 CFR 63.7565, Table 10)**

5. The permittee shall comply with the applicable requirements of 40 CFR Part 63, Subpart DDDDD - National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters. **(40 CFR Part 63, Subpart DDDDD)**

Footnotes:
[1] This condition is state only enforceable and was established pursuant to Rule 201(1)(b).
[2] This condition is federally enforceable and was established pursuant to Rule 201(1)(a).

EUCAT3DIESEL
EMISSION UNIT CONDITIONS

DESCRIPTION

On-site, stationary, diesel-fired internal combustion engine, 9.4 MMBTU/hr heat input; emergency use only. This unit is subject to the provisions of 40 CFR Part 63, Subpart ZZZZ.

Flexible Group ID: NA

POLLUTION CONTROL EQUIPMENT

NA

I. EMISSION LIMIT(S)

NA

II. MATERIAL LIMIT(S)

Material	Limit	Time Period/ Operating Scenario	Equipment	Monitoring/ Testing Method	Underlying Applicable Requirements
1. Fuel Oil – sulfur content	1.0% by weight at 18,000 BTU/lb	Instantaneous; at all times	EUCAT3DIESEL	SC VI.6 (Use of No. 2 Fuel Oil, which by definition contains <0.5% Sulfur by weight; see **Appendix 3-C-1**)	**R 336.1401(1), Table 41**

III. PROCESS/OPERATIONAL RESTRICTION(S)

1. The permittee shall:
   a. Change oil and filter every 500 hours of operation or annually, whichever comes first, except as allowed in SC III.2;
   b. Inspect the air filter every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; and
   c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.

   If the emergency engine is being operated during an emergency and it is not possible to shut down the engine to perform the work practice standards on the schedule required, the work practice standard can be delayed until the emergency is over. The work practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under Federal, State or local law has been abated. Sources must report any failure to perform the work practice on the schedule required and the Federal, State or local law or which the risk was deemed unacceptable. **(40 CFR 63.6602, 40 CFR Part 63, Subpart ZZZZ, Table 2c, Item 1)**

2. The permittee may utilize an oil analysis program in order to extend the specified oil change requirement. The oil analysis must be performed at the same frequency as oil changes are required. The oil analysis must be performed at the same frequency specified for changing the oil in Table 2c of 40 CFR Part 63, Subpart ZZZZ. **(40 CFR 63.6625(i))**

3. The permittee shall install, maintain and operate EUCAT3DIESEL and after-treatment control device (if any) according to the manufacturer's emission-related written instructions or develop your own maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions. **(40 CFR 63.6605, 40 CFR 63.6625(e))**

4. The permittee shall minimize the time spent at idle during startup and minimize the startup time EUCAT3DIESEL to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the emission standards applicable to all times other than startup apply. **(40 CFR 63.6625(h))**

5. There is no time limit on the use of emergency stationary RICE in emergency situations. **(40 CFR 63.6640(f)(1))**

6. The permittee may operate EUCAT3DIESEL for no more than 100 hours per calendar year for the purpose of necessary maintenance checks and readiness testing, provided that the tests are recommended by Federal, State, or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The permittee may petition the Department for approval of additional hours to be used for maintenance checks and readiness testing. A petition is not required if the owner or operator maintains records indicating that Federal, State, or local standards require maintenance and testing of emergency internal combustion engines beyond 100 hours per calendar year. **(40 CFR 63.6640(f)(2))**

7. EUCAT3DIESEL may operate up to 50 hours per calendar year in non-emergency situations, but those 50 hours are counted towards the 100 hours per calendar year provided for maintenance and testing as provided in 40 CFR 63.6640(f)(2). The 50 hours per calendar year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for the permittee to supply non-emergency power as part of a financial arrangement with another entity. **(40 CFR 63.6640(f)(3))**

IV. DESIGN/EQUIPMENT PARAMETER(S)

1. The permittee shall install a non-resettable hour meter on each engine in EUCAT3DIESEL. **(40 CFR 63.6625(f))**

V. TESTING/SAMPLING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. If using the oil analysis program, the permittee must at a minimum analyze the following three parameters: Total Base Number, viscosity, and percent water content. The condemning limits for these parameters are as follows: Total Base Number is less than 30% of the Total Base Number of the oil when new; viscosity of the oil has changed by more than 20% from the viscosity of the oil when new; or percent water content (by volume) is greater than 0.5. If all of these condemning limits are not exceeded, the engine owner or operator is not required to change the oil. If any of the limits are exceeded, the engine owner or operator must change the oil within 2 business days of receiving the results of the analysis; if the engine is not in operation when the results of the analysis are received, the engine owner or operator must change the oil within 2 business days or before commencing operation, whichever is later. The owner or operator must keep records of the parameters that are analyzed as part of the program, the results of the analysis, and the oil changes for the engine. The analysis program must be part of the maintenance plan for the engine. **(40 CFR 63.6625(i))**

See Appendix 3-C

VI. MONITORING/RECORDKEEPING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. The permittee shall keep in a satisfactory manner, records of the occurrence and duration of each malfunction of operation or the air pollution control monitoring equipment. The permittee shall keep all records on file and make them available to the department upon request. **(40 CFR 63.6655(a)(2), 40 CFR 63.6660)**

2. The permittee shall keep in a satisfactory manner, records of actions taken during periods of malfunction to minimize emissions, including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation. The permittee shall keep all records on file and make them available to the department upon request. **(40 CFR 63.6655(a)(5), 40 CFR 63.6660)**

3. The permittee shall keep in a satisfactory manner, records to demonstrate continuous compliance with the operating limitations. The permittee shall keep all records on file and make them available to the department upon request. **(40 CFR 63.6655(d), 40 CFR 63.6660)**

4. The permittee shall keep in a satisfactory manner, records of the maintenance conducted to demonstrate that the engine and after-treatment control device (if any) were operated and maintained according to the developed maintenance plan. The permittee shall keep all records on file and make them available to the department upon request. **(40 CFR 63.6655(e), 40 CFR 63.6660)**

5. The permittee shall monitor and record the total hours of operation for EUCAT3DIESEL per calendar year, recorded through the non-resettable hours meter, in a manner acceptable to the AQD District Supervisor. The permittee shall document how many hours are spent for emergency operation; including what classified the operation as emergency and how many hours are spent for non-emergency operation. If the engine is used for the purposes specified in 40 CFR 63.6640(f)(4)(ii), the permittee must keep records of the notification of the emergency situation, and the date, start time, and end time of engine operation. **(40 CFR 63.6655(f))**

6. The permittee shall maintain sufficient records to demonstrate that the sulfur content for each shipment of fuel oil received is less than 1.0% by weight. **(R 336.1213(3))**

7. The permittee shall conduct and maintain records of a daily (non-certified) visual observation for opacity in order to verify proper firing, whenever an engine is in use for 24 consecutive hours or more. **(R 336.1213(3))**

8. The permittee shall maintain a record of the applicability determination for each Reciprocating Internal Combustion Engine (RICE) relative to the requirements of 40 CFR Part 63, Subparts A and ZZZZ. **(40 CFR Part 63, Subpart A, Section 63.10(b)(3))**

See Appendix 3-C (Fuel Oil Sulfur Monitoring)

VII. REPORTING

1. Prompt reporting of deviations pursuant to General Conditions 21 and 22 of Part A. **(R 336.1213(3)(c)(ii))**

2. Semiannual reporting of monitoring and deviations pursuant to General Condition 23 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for reporting period July 1 to December 31 and September 15 for reporting period January 1 to June 30. **(R 336.1213(3)(c)(i))**

3. Annual certification of compliance pursuant to General Conditions 19 and 20 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for the previous calendar year. **(R 336.1213(4)(c))**

4. The permittee shall submit to the AQD District Supervisor, a semiannual compliance report, as specified in 40 CFR 63.6650, which contains all deviations during the reporting period from any applicable emission limitation or operating limitation. If there are no deviations from any applicable emission limitations or operating limitations, the report shall contain a statement that there were no deviations during the reporting period. The first report shall cover the period beginning on the applicable compliance date specified in 40 CFR 63.6595 and ending on June 30 (postmarked or delivered by July 31) or December 31 (postmarked or delivered by January 31), whichever date is the first date following the end of the first calendar half after the applicable compliance date. Each subsequent report must cover the semiannual period from January 1 through June 30, or from July 1 through December 31. The subsequent reports must be postmarked or delivered by July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period, except as allowed in 40 CFR 63.6650(b)(5). The compliance report must also contain the following information, as specified in 40 CFR 63.6650(c) and (d):
   a. Company name and address.
   b. Certification of the report by a responsible official.
   c. Date of report and beginning and ending dates of the reporting period.
   d. The number of malfunctions, including a brief description of each event, that occurred during the reporting period and a demonstration that the Malfunction Plan was followed during such events.
   e. The total operating time of the RICE at which the deviation occurred during the reporting period.
   f. The number, duration, and cause of deviations and the corrective action taken.

   A copy of the compliance report shall be kept on file for a period of at least five years (at least two years at the site) and made available to the Department upon request. **(40 CFR 63.6640(b), 40 CFR 63.6650(b),(c),(d), 40 CFR 63.6660)**

5. Each affected source that has obtained a Title V operating permit pursuant to 40 CFR Part 70 or 71 must report all deviations as defined in 40 CFR Part 63, Subpart ZZZZ in the semiannual monitoring report required by 40 CFR 70.6 (a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A). If an affected source submits a Compliance report pursuant to Table 7 of 40 CFR Part 63, Subpart ZZZZ along with, or as part of, the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), and the Compliance report includes all required information concerning deviations from any emission or operating limitation in 40 CFR Part 63, Subpart ZZZZ, submission of the Compliance report shall be deemed to satisfy any obligation to report the same deviations in the semiannual monitoring report. However, submission of a Compliance report shall not otherwise affect any obligation the affected source may have to report deviations from permit requirements to the permit authority. **(40 CFR 63.6650(f))**

6. For any engine that is an emergency stationary engine with a site rating of more than 100 brake hp that operates or is contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in 40 CFR 63.6640(f)(2)(ii) and (iii) or that operates for the purpose specified in 40 CFR 63.6640(f)(4)(ii), you must submit an annual report according to the requirements below and as specified in 40 CFR 63.6650(h): **(40 CFR 63.6650(h), 40 CFR 63.6660)**

   a. The report must contain the following information:
      i. Company name and address where the engine is located.
      ii. Date of the report and beginning and ending dates of the reporting period.
      iii. Engine site rating and model year.
      iv. Latitude and longitude of the engine in decimal degrees reported to the fifth decimal place.
      v. Hours operated for the purposes specified in 40 CFR 63.6640(f)(2)(ii) and (iii), including the date, start time, and end time for engine operation for the purposes specified in 40 CFR 63.6640(f)(2)(ii) and (iii).
      vi. Number of hours the engine is contractually obligated to be available for the purposes specified in 40 CFR 63.6640(f)(2)(ii) and (iii).

vii. Hours spent for operation for the purpose specified in 40 CFR 63.6640(f)(4)(ii), including the date, start time, and end time for engine operation for the purposes specified in 40 CFR 63.6640(f)(4)(ii). The report must also identify the entity that dispatched the engine and the situation that necessitated the dispatch of the engine.

viii. If there were no deviations from the fuel requirements in 40 CFR 63.6604 that apply to the engine (if any), a statement that there were no deviations from the fuel requirements during the reporting period.

ix. If there were deviations from the fuel requirements in 40 CFR 63.6604 that apply to the engine (if any), information on the number, duration, and cause of deviations, and the corrective action taken.

b. The annual report must be submitted electronically using the subpart specific reporting form in the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through USEPA's Central Data Exchange (CDX) (www.epa.gov/cdx). However, if the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, the written report must be submitted to the Administrator at the appropriate address listed in 40 CFR 63.13.

See Appendix 8

VIII. STACK/VENT RESTRICTION(S)

NA

IX. OTHER REQUIREMENT(S)

1. The permittee shall comply with the provisions of the National Emission Standards for Hazardous Air Pollutants, as specified in 40 CFR Part 63, Subparts A and ZZZZ, as they apply to EUCAT3DIESEL. **(40 CFR Part 63, Subparts A and ZZZZ)**

Footnotes:
[1] This condition is state only enforceable and was established pursuant to Rule 201(1)(b).
[2] This condition is federally enforceable and was established pursuant to Rule 201(1)(a).

EUCATDIESEL12
EMISSION UNIT CONDITIONS

DESCRIPTION

A 2,000-kilowatt (kW) diesel-fueled emergency engine manufactured in 2007 or later. This unit is subject to the provisions of 40 CFR Part 60, Subpart IIII and 40 CFR Part 63, Subpart ZZZZ.
Flexible Group ID: NA

POLLUTION CONTROL EQUIPMENT

NA

I. EMISSION LIMIT(S)

Pollutant	Limit	Time Period / Operating Scenario	Equipment	Monitoring/ Testing Method	Underlying Applicable Requirements
1. NMHC + NOx	6.4 g/kW-hr[2]	Hourly	EUCATDIESEL12	SC V.1 SC VI.2	**40 CFR 60.4205(b)**
2. CO	3.5 g/kW-hr[2]	Hourly	EUCATDIESEL12	SC V.1 SC VI.2	**40 CFR 60.4205(b)**
3. PM	0.20 g/kW-hr[2]	Hourly	EUCATDIESEL12	SC V.1 SC VI.2	**40 CFR 60.4205(b)**

II. MATERIAL LIMIT(S)

1. The permittee shall burn only diesel fuel, in EUCATDIESEL12, with a sulfur content not to exceed 15 ppm (0.0015%) by weight.[2] **(R 336.1205(3), R 336.1402(1), 40 CFR 60.4207, 40 CFR 80.510(b))**

III. PROCESS/OPERATIONAL RESTRICTION(S)

1. The permittee shall not operate EUCATDIESEL12 for more than 500 hours per year on a 12-month rolling time period basis as determined at the end of each calendar month. The 500 hours includes the 100 hours for the purpose of necessary maintenance checks and readiness testing as described in SC III.2.[2] **(R 336.1205(3), R 336.1225, R 336.1702(a), R 336.2803, R 336.2804, 40 CFR 52.21(c) & (d))**

2. The permittee may operate EUCATDIESEL12 for no more than 100 hours per calendar year, as determined at the end of each calendar month, for the purpose of necessary maintenance checks and readiness testing, provided that the tests are recommended by Federal, State, or local government, the manufacturer, the vendor, or the insurance company associated with the engine. The permittee may petition the Department for approval of additional hours to be used for maintenance checks and readiness testing. A petition is not required if the owner or operator maintains records indicating that Federal, State, or local standards require maintenance and testing of emergency internal combustion engines beyond 100 hours per calendar year. EUCATDIESEL12 may operate up to 50 hours per calendar year in non-emergency situations, but those 50 hours are counted towards the 100 hours per calendar year provided for maintenance and testing. The 50 hours per calendar year for non-emergency situations may not be used for peak shaving or to generate income for a facility to supply non-emergency power as part of a financial arrangement with another entity.[2] **(40 CFR 60.4211(f), 40 CFR 63.6640(f)**

3. The permittee shall install, maintain, and operate EUCATDIESEL12 according to the manufacturer emissions-related written instructions, or procedures developed by the owner/operator and approved by the engine manufacturer, over the entire life of the engine.[2] **(R 336.1205(3), R 336.1225, R 336.1911, R 336.2803, R 336.2804, 40 CFR 52.21(c) & (d), 40 CFR 60.4206, 40 CFR 60.4211)**

4. There is no time limit on the use of emergency stationary RICE in emergency situations. **(40 CFR 60.4211(f)(1), 40 CFR 63.6640(f)(1)**

IV. DESIGN/EQUIPMENT PARAMETER(S)

1. The permittee shall equip and maintain EUCATDIESEL12 with a non-resettable hours meter to track the operating hours.[2] **(R 336.1205(3), R 336.1225, 40 CFR 60.4209(a), 40 CFR 63.6625(f))**

2. The nameplate capacity of EUCATDIESEL12 shall not exceed 2,000 kW, as certified by the equipment manufacturer.[2] **(R 336.1205(3))**

V. TESTING/SAMPLING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. The permittee shall conduct an initial performance test for EUCATDIESEL12 within one year after startup of the engine to demonstrate compliance with the emission limits in 40 CFR 60.4205 unless the engine has been certified by the manufacturer and the permittee maintains the engine as required by 40 CFR Part 60, Subpart IIII. If a performance test is required, the performance tests shall be conducted at the owner's expense, in accordance with Department requirements and according to 40 CFR 60.4212. No less than 30 days prior to testing, the permittee shall submit a complete test plan to the AQD Technical Programs Unit and District Office. The AQD must approve the final plan prior to testing, including any modifications to the method in the test protocol that are proposed after initial submittal. The permittee must submit a complete report of the test results to the AQD Technical Programs Unit and District Office within 60 days following the last date of the test.[2] **(40 CFR 60.4211)**

2. The permittee shall notify the AQD Technical Programs Unit Supervisor and the District Supervisor not less than 7 days of the time and place before performance tests are conducted. **(R 336.1213(3))**

See Appendix 5

VI. MONITORING/RECORDKEEPING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. The permittee shall complete all required calculations in a format acceptable to the AQD District Supervisor by the last day of the calendar month, for the previous calendar month, unless otherwise specified in any monitoring/recordkeeping special condition.[2] **(R 336.1205(3), R 336.2803, R 336.2804, 40 CFR 52.21 (c) & (d))**

2. The permittee shall keep, in a satisfactory manner, a record of testing required in SC V.1 or manufacturer certification documentation indicating that EUCATDIESEL12 meets the applicable emission limitations contained in the federal Standards of Performance for New Stationary Sources 40 CFR Part 60, Subpart IIII. The permittee shall keep all records on file and make them available to the Department upon request.[2] **(40 CFR 60.4211)**

3. The permittee shall monitor and record the total hours of operation and the hours of operation during non-emergencies for EUCATDIESEL12, on a monthly and 12-month rolling time period basis, in a manner acceptable to the AQD District Supervisor. The permittee shall document how many hours are spent for emergency operation of EUCATDIESEL12, including what classified the operation as emergency and how many hours are spent for maintenance or readiness testing and non-emergency operation.[2] **(R 336.1205(3), R 336.2803, R 336.2804, 40 CFR 60.4211(f), 40 CFR 60.4214(b))**

4. The permittee shall keep, in a satisfactory manner, fuel supplier certification records or fuel sample test data, for each delivery of diesel fuel oil used in EUCATDIESEL12, demonstrating that the fuel sulfur content meets the requirement of 40 CFR 80.510(b). The certification or test data shall include the name of the oil supplier or laboratory, and the sulfur content of the fuel oil.[2] **(R 336.1205(3), R 336.1402(1), 40 CFR 80.510(b))**

See Appendix 3-C

VII. REPORTING

1. The permittee shall submit all applicable notifications specified in 40 CFR 63.7(b) and (c), 40 CFR 63.8 (e), (f)(4), and (f)(6), and 40 CFR 63.9(b) through (e), (g), and (h) by the dates specified.[2] **(40 CFR 63.6645(a)(3) and (f))**

2. Prompt reporting of deviations pursuant to General Conditions 21 and 22 of Part A. **(R 336.1213(3)(c)(ii))**

3. Semiannual reporting of monitoring and deviations pursuant to General Condition 23 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for reporting period July 1 to December 31 and September 15 for reporting period January 1 to June 30. **(R 336.1213(3)(c)(i))**

4. Annual certification of compliance pursuant to General Conditions 19 and 20 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for the previous calendar year. **(R 336.1213(4)(c))**

5. The permittee shall submit any performance test reports to the AQD Technical Programs Unit and District Office, in a format approved by the AQD. **(R 336.1213(3)(c), R 336.2001(5))**

See Appendix 8

VIII. STACK/VENT RESTRICTION(S)

The exhaust gases from the stacks listed in the table below shall be discharged unobstructed vertically upwards to the ambient air unless otherwise noted:

Stack & Vent ID	Maximum Exhaust Diameter/ Dimensions (inches)	Minimum Height Above Ground (feet)	Underlying Applicable Requirements
1. SVCATDIESEL12	18[2]*	47[2]	**R 336.1225** **R 336.2803** **R 336.2804** **40 CFR 52.21 (c) & (d)**

* The maximum diameter applies to the exhaust stack itself and does not apply to any no-loss rain sleeve that may be in use.

IX. OTHER REQUIREMENT(S)

1. The permittee shall comply with the provisions of the federal Standards of Performance for New Stationary Sources as specified in 40 CFR Part 60, Subparts A and IIII, as they apply to EUCATDIESEL12.[2] **(40 CFR Part 60, Subparts A & IIII,)**

2. The permittee shall comply with the provisions of the National Emission Standards for Hazardous Air Pollutants, as specified in 40 CFR Part 63, Subparts A and ZZZZ, as they apply to EUCATDIESEL12 upon startup.[2] **(40 CFR Part 63, Subparts A and ZZZZ, 40 CFR 63.6595)**

Footnotes:
[1] This condition is state only enforceable and was established pursuant to Rule 201(1)(b).
[2] This condition is federally enforceable and was established pursuant to Rule 201(1)(a).

EUGUARDSHK_ENG
EMISSION UNIT CONDITIONS

DESCRIPTION

A natural-gas, stationary internal combustion engine rated at 40 HP; Emergency Generator for the guard shack. This unit is subject to the provisions of 40 CFR Part 60, Subpart JJJJ and 40 CFR Part 63, Subpart ZZZZ.

Flexible Group ID: NA

POLLUTION CONTROL EQUIPMENT

NA

I. EMISSION LIMIT(S)

Pollutant	Limit	Time Period/ Operating Scenario	Equipment	Monitoring/ Testing Method	Underlying Applicable Requirements
1. NOx + Hc	10 g/kW-hr g/hp-hr	Hourly	EUGUARDSHK_ENG	SC VI.2	**40 CFR 60.6233(d)**
2. 2. CO	387 g/hp-hr	Hourly	EUGUARDSHK_ENG	SC VI.2	**40 CFR 60.6233(d)**

II. MATERIAL LIMIT(S)

1. The permittee shall burn only field or pipeline quality natural gas, in each engine in EUGUARDSHK_ENG. **(40 CFR 60.4230, R 336.1213(3))**

III. PROCESS/OPERATIONAL RESTRICTION(S)

1. There is no time limit on the use of emergency stationary RICE in emergency situations. **(40 CFR 60.4243(d)(1))**

2. The permittee may operate EUGUARDSHK_ENG for no more than 100 hours per calendar year for the purpose of necessary maintenance checks and readiness testing, provided that the tests are recommended by Federal, State, or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The permittee may petition the Department for approval of additional hours to be used for maintenance checks and readiness testing. A petition is not required if the owner or operator maintains records indicating that Federal, State, or local standards require maintenance and testing of emergency internal combustion engines beyond 100 hours per calendar year. **(40 CFR 60.4243(d)(2), 40 CFR 63.6640(f))**

3. EUGUARDSHK_ENG may operate up to 50 hours per calendar year in non-emergency situations, but those 50 hours are counted towards the 100 hours per calendar year provided for maintenance and testing as provided in 40 CFR 60.4243(d)(2). The 50 hours per calendar year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for the permittee to supply non-emergency power as part of a financial arrangement with another entity. **(40 CFR 60.4243(d)(3), 40 CFR 63.6640(f))**

4. The permittee shall operate and maintain EUGUARDSHK_ENG such that it meets the emission limits in SC I.1, and I.2 over the entire life of the engine. **(40 CFR 60.4234, 40 CFR 60.4243(b))**

5. If the permittee purchased a certified engine, according to procedures specified in 40 CFR Part 60, Subpart JJJJ, for the same model year, the permittee shall meet the following requirements for EUGUARDSHK_ENG:

   a. Operate and maintain the certified engine and control device according to the manufacturer's emission-related written instructions;

b. Keep a maintenance plan and the permittee may only change those engine settings that are permitted by the manufacturer. If you do not operate and maintain the certified engine and control device according to the manufacturer's emission-related written instructions, the engine will be considered a non-certified engine; and

c. Meet the requirements as specified in 40 CFR Part 1068, Subparts A through D.

If the permittee does not operate and maintain the certified engine and control device according to the manufacturer's emission-related written instructions, the engine will be considered a non-certified engine and be subject to SC III.5. **(40 CFR 60.4243(b)(1))**

6. If the permittee purchased a non-certified engine or a certified engine operating in a non-certified manner, the permittee shall keep a maintenance plan for EUGUARDSHK_ENG and shall, to the extent practicable, maintain and operate each engine in a manner consistent with good air pollution control practice for minimizing emissions. **(40 CFR 60.4243(b)(2))**

IV. DESIGN/EQUIPMENT PARAMETER(S)

1. EUGUARDSHK_ENG shall be certified to meet the applicable emission standard of 40 CFR 60.4233. The permittee shall install and configure each engine according to the manufacturer's specifications. **(40 CFR 60.4243)**

2. The permittee shall equip and maintain EUGUARDSHK_ENG with non-resettable hours meters to track the operating hours. **(40 CFR 60.4237, 40 CFR 63.6655(f))**

3. The nameplate capacity of EUGUARDSHK_ENG shall not exceed 500 BHP, as certified by the equipment manufacturer. **(40 CFR 63.6590(c)(4))**

V. TESTING/SAMPLING

1. The permittee shall conduct an initial performance test for EUGUARDSHK_ENG within one year after startup of the engine to demonstrate compliance with the emission limits in 40 CFR 60.4231 unless the engine has been certified by the manufacturer and the permittee maintains the engine as required by 40 CFR Part 60, Subpart JJJJ. If a performance test is required, the performance test shall be conducted at the owner's expense, in accordance with Department requirements and according to 40 CFR 60.4244. No less than 30 days prior to testing, the permittee shall submit a complete test plan to the AQD Technical Programs Unit and District Office. The AQD must approve the final plan prior to testing, including any modifications to the method in the test protocol that are proposed after initial submittal. The permittee must submit a complete report of the test results to the AQD Technical Programs Unit and District Office within 60 days following the last date of the test.[2] **(40 CFR 60.4244)**

2. The permittee shall notify the AQD Technical Programs Unit Supervisor and the District Supervisor not less than 7 days of the time and place before performance tests are conducted. **(R 336.1213(3))**

VI. MONITORING/RECORDKEEPING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. The permittee shall keep in a satisfactory manner, records of all maintenance conducted on EUGUARDSHK_ENG. The permittee shall keep all records on file and make them available to the department upon request. **(40 CFR 60.4245(a)(2))**

2. The permittee shall keep, in a satisfactory manner, a record of testing required in SC V.1 or manufacturer certification documentation indicating that EUGUARDSHK_ENG meets the applicable emission limitations contained in the federal Standards of Performance for New Stationary Sources 40 CFR Part 60, Subpart JJJJ. The permittee shall keep all records on file and make them available to the Department upon request. **(40 CFR 60.4245)**

3. The permittee shall monitor and record the hours of operation of EUGUARDSHK_ENG during emergencies and non-emergencies, on a calendar year basis, in a manner acceptable to the AQD District Supervisor. The permittee shall record the time of operation of EUGUARDSHK_ENG and the reason it was in operation during that time. **(40 CFR 60.4243)**

See Appendix 4

VII. REPORTING

1. Prompt reporting of deviations pursuant to General Conditions 21 and 22 of Part A. **(R 336.1213(3)(c)(ii))**

2. Semiannual reporting of monitoring and deviations pursuant to General Condition 23 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for reporting period July 1 to December 31 and September 15 for reporting period January 1 to June 30. **(R 336.1213(3)(c)(i))**

3. Annual certification of compliance pursuant to General Conditions 19 and 20 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for the previous calendar year. **(R 336.1213(4)(c))**

See Appendix 8

VIII. STACK/VENT RESTRICTION(S)

NA

IX. OTHER REQUIREMENT(S)

1. The permittee shall comply with the provisions of the federal Standards of Performance for New Stationary Sources as specified in 40 CFR Part 60, Subparts A and JJJJ, as they apply to EUGUARDSHK_ENG. **(40 CFR Part 60, Subparts A and JJJJ)**

2. The permittee shall comply with all applicable provisions of the National Emission Standards for Hazardous Air Pollutants, as specified in 40 CFR Part 63, Subparts A and ZZZZ, for Stationary Reciprocating Internal Combustion Engines by the initial compliance date. **(40 CFR 63.6595, 40 CFR Part 63, Subparts A and ZZZZ)**

Footnotes:
[1] This condition is state only enforceable and was established pursuant to Rule 201(1)(b).
[2] This condition is federally enforceable and was established pursuant to Rule 201(1)(a).

D. FLEXIBLE GROUP SPECIAL CONDITIONS

Part D outlines the terms and conditions that apply to more than one emission unit. The permittee is subject to the special conditions for each flexible group in addition to the General Conditions in Part A and any other terms and conditions contained in this ROP.

The permittee shall comply with all specific details in the special conditions and the underlying applicable requirements cited. If a specific condition type does not apply, NA (not applicable) has been used in the table. If there are no special conditions that apply to more than one emission unit, this section will be left blank.

FLEXIBLE GROUP SUMMARY TABLE

The descriptions provided below are for informational purposes and do not constitute enforceable conditions.

Flexible Group ID	Flexible Group Description	Associated Emission Unit IDs
FGBOILER12	The common 40 CFR Part 64 (CAM) requirements for these emission units are in this flexible group.	EUBOILER1 EUBOILER2
FGMATS_U12	Common applicable Mercury and Air Toxics Standard requirements for EUBOILER1 and EUBOILER2.	EUBOILER1 EUBOILER2
FGMATS_U3	Mercury and Air Toxics Standard requirements for EUBOILER3.	EUBOILER3
FGEXISTINGRICE	Onsite, stationary diesel-fired internal combustion engines. Engines used as a source of emergency power or water supply that are subject to the RICE MACT.	EUCATFIREPUMP3 EUHPHSWP15001 EUHPHSWP15002 EUHPHSWP3000
FGAUXBLRS3	Distillate oil fired auxiliary boilers less than 10 MMBTU.	EUAUXBLR3B EUAUXBLR3C
FGNEWCIRICE	New stationary diesel-fired internal combustion, compression ignition engines. Engines used as a source of emergency power or water supply that are subject to the RICE MACT.	EUWPDIESEL EUTRNCNTRDIESEL
FGPARTSCLEANERS	Any cold cleaner that is grandfathered or exempt from Rule 201 pursuant to Rule 278, 278a and Rule 281(2)(h) or Rule 285(2)(r)(iv). Existing cold cleaners were placed into operation prior to July 1, 1979. New cold cleaners were placed into operation on or after July 1, 1979.	EUPARTSCLEANERS

FGBOILER12
FLEXIBLE GROUP CONDITIONS

DESCRIPTION

The common 40 CFR Part 64 (CAM) requirements for these emission units are in this flexible group.

Emission Units: EUBOILER1, EUBOILER2

POLLUTION CONTROL EQUIPMENT

Pollution control equipment is described for each unit in EUBOILER1 and EUBOILER2.

I. EMISSION LIMIT(S)

NA

II. MATERIAL LIMIT(S)

NA

III. PROCESS/OPERATIONAL RESTRICTION(S)

NA

IV. DESIGN/EQUIPMENT PARAMETER(S)

NA

V. TESTING/SAMPLING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. The permittee shall assess opacity using USEPA Reference Method 9 - "Visual Determination of the Opacity of Emissions from Stationary Sources", upon the request of AQD.[2] **(R 336.1301)**

See Appendices 3-A and 5

VI. MONITORING/RECORDKEEPING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. The permittee shall utilize COMS-recorded opacity as an indicator of the emission unit's compliance with the particulate matter limit, except during periods of monitoring and system malfunction, system repairs or QA/QC activities. The appropriate range of opacity defining proper function of the PJFF is 0-20% opacity. An excursion is defined as any two (2) or more consecutive 1-hour block average opacity values greater than 15%. **(40 CFR 64.6(c)(1)(i) and (ii))**

2. The permittee shall continuously monitor and record any alarms and corrective actions taken. **(40 CFR 64.6(c)(1)(i) and (ii))**

3. The permittee shall properly maintain the COMS, including completing daily COMS zero and calibration tests; conduct necessary preventative maintenance; maintaining necessary parts for routine repairs of the monitoring equipment; and demonstrating adequate performance through an annual monitor audit. **(40 CFR 64.6(c)(1)(iii), 40 CFR 64.7(b))**

4. Except for, as applicable, monitoring malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), the owner or operator shall conduct all monitoring in continuous operation (or shall collect data at all required intervals) at all times that the pollutant-specific emissions unit is operating. Data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities shall not be used for purposes of this part, including data averages and calculations or fulfilling a minimum data availability requirement, if applicable. The owner or operator shall use all the data collected during all other periods in assessing the operation of the control device and associated control system. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions. The permittee shall operate the COMS during all required periods when the coal-fired boiler is operating. Data recorded during monitoring malfunctions, repair activities and QA/QC operations shall not be used for 40 CFR Part 64 compliance. **(40 CFR 64.6(c)(3), 40 CFR 64.7(c))**

5. The permittee shall conduct all required monitoring per the CAM Plan and otherwise satisfy the requirements specified in 40 CFR 64.7 through 40 CFR 64.9. **(40 CFR 64.6(c)(3), 40 CFR 64.7(a))**

6. The required COMS shall collect data for all required intervals when the emission unit is operating. **(40 CFR 64.7(c)(1)(iii))**

7. The permittee shall restore operation of the emission unit, control device, and associated pollutant capture system equipment to normal/compliant operation as quickly as possible, in accordance with good air pollution control practices for minimizing emissions in response to any noted exceedance or excursion. Excursions shall trigger an internal investigation, corrective action(s) per the MAP, and a CAM excursion summary reporting requirement. Necessary response shall include minimizing the period of any startup, shutdown or malfunction and taking necessary corrective actions to restore normal operation and prevent the likely recurrence of the cause of the excursion or exceedance (other than those caused by excused startup or shutdown conditions). **(40 CFR 64.7(d))**

8. If the permittee identifies a failure to achieve compliance with an emission limitation or standard for which the approved monitoring did not provide an indication of an excursion or exceedance while providing valid data, or the results of compliance or performance testing document a need to modify the existing indicator ranges or designated conditions, the permittee shall promptly notify the AQD and if necessary, submit a proposed modification of the ROP and CAM Plan to address the necessary monitoring changes. Such a modification may include but is not limited to, reestablishing indicator ranges or designated conditions, modifying the frequency of conducting monitoring and collecting data, or the monitoring of additional parameters. **(40 CFR 64.7(e))**

See Appendices 3-A, 3-B and 3-D

VII. REPORTING

1. Prompt reporting of deviations pursuant to General Conditions 21 and 22 of Part A. **(R 336.1213(3)(c)(ii))**

2. Semiannual reporting of monitoring and deviations pursuant to General Condition 23 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for reporting period July 1 to December 31 and September 15 for reporting period January 1 to June 30. **(R 336.1213(3)(c)(i))**

3. Annual certification of compliance pursuant to General Conditions 19 and 20 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for the previous calendar year. **(R 336.1213(4)(c))**

4. Quarterly reporting of monthly excess sulfur dioxide emissions (including the nature and cause of the periods of excess emissions), and of the dates and times of the monitoring systems being inoperative. Each quarterly report is due within 30 days of the calendar quarter reporting period. **(R 336.2170)**

5. Quarterly reporting of excess opacity emissions (including the nature and cause of the periods of excess emissions), and of the dates and times of the monitoring systems being inoperative. Each quarterly report is due within 30 days of the calendar quarter reporting period. **(R 336.2170)**

6. Each semiannual report of monitoring deviations shall include summary information on the number, duration, and cause of exceedances/excursions in the reporting period; and the corrective actions taken in response. If there were no excursions and/or exceedances in the reporting period, then this report shall include a statement that there were no excursions and/or exceedances. **(40 CFR 64.9(a)(2)(i))**

7. Each semiannual report of monitoring deviations shall include summary information on monitor downtime in the reporting period. If there were no periods of monitor downtime in the reporting period, then this report shall include a statement that there were no periods of monitor downtime. **(40 CFR 64.9(a)(2)(ii))**

8. Each semiannual report of monitoring deviations shall include a description of the actions taken to implement a Quality Improvement Plan (QIP) during the reporting period, if appropriate. If a QIP has been completed, the report shall include documentation that the QIP has been implemented, and a discussion pertaining to whether the QIP implementation has reduced the likelihood of excursions or exceedances. **(40 CFR 64.9(a)(2)(iii))**

See Appendix 8

VIII. STACK/VENT RESTRICTION(S)

The exhaust gases from the stacks listed in the table below shall be discharged unobstructed vertically upwards to the ambient air unless otherwise noted:

Stack & Vent ID	Maximum Exhaust Dimensions (inches)	Minimum Height Above Ground (feet)	Underlying Applicable Requirements
1. SVBLR12	228[2]	400[2]	**R 336.1225** **R 336.2803** **R 336.2804** **40 CFR 52.21(c) and (d)**

IX. OTHER REQUIREMENT(S)

1. The permittee shall comply with all applicable requirements of 40 CFR Part 64. **(40 CFR Part 64)**

Footnotes:
[1]This condition is state only enforceable and was established pursuant to Rule 201(1)(b).
[2]This condition is federally enforceable and was established pursuant to Rule 201(1)(a).
[3]This condition is federally enforceable and was originally established in the consent decree settling, "U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" and also pursuant to Act 451, Section 324.5503(b), and will remain in effect after termination of the consent decree.
[4]Definitions specific to this condition may be found in Appendix 1-B: Definitions Applicable to Specified Permit Conditions.

FGMATS_U12
FLEXIBLE GROUP CONDITIONS

DESCRIPTION

40 CFR Part 63, Subpart UUUUU (Mercury and Air Toxics Standards or MATS) requirements for existing coal-fired electric utility steam generating unit(s) (EGU) rated more than 25 megawatts electric (MWe) that serve(s) a generator producing electricity for sale and designed to burn coal that is not low rank virgin coal (calorific value of ≥ 8,300 BTU/pound).

Emission Units: EUBOILER1 and EUBOILER2

POLLUTION CONTROL EQUIPMENT

EUBOILER1:
Low-NOx burners,
Sorbent injection (ACI) (activated carbon or other sorbent) for mercury control,
Dry sorbent injection (DSI) (hydrated lime or other sorbent) for acid gas control,
Pulse-jet fabric filter (PJFF) baghouse for PM control.

EUBOILER2:
Low-NOx burners,
Selective catalytic reduction (SCR),
Sorbent injection (ACI) (activated carbon or other sorbent) for mercury control,
Dry sorbent injection (DSI) (hydrated lime or other sorbent) for acid gas control,
Pulse-jet fabric filter (PJFF) baghouse for PM control.

I. EMISSION LIMIT(S)

Pollutant	Limit	Time Period/ Operating Scenario	Equipment	Monitoring/ Testing Method	Underlying Applicable Requirements
1. Filterable PM (per boiler)	0.030 lb/MMBTU*	Quarterly or Triennial Stack Test+	EUBOILER1 EUBOILER2	SC V.1	**40 CFR 63.9991 40 CFR Part 63, Subpart UUUUU, Table 2.1.a**
2. Hydrogen chloride (HCl) (per boiler)	0.0020 lb/MMBTU*	Quarterly or Triennial Stack Test+	EUBOILER1 EUBOILER2	SC V.2	**40 CFR 63.9991 40 CFR Part 63, Subpart UUUUU, Table 2.1.b**
3. Mercury (Hg) (per boiler)	1.2 lb/TBTU*	30-boiler operating day rolling arithmetic average updated at the end of each new boiler operating day	EUBOILER1 EUBOILER2	SC V.3 SC VI.3	**40 CFR 63.9991 40 CFR Part 63, Subpart UUUUU, Table 2.1.c**

* The emission limits apply at all times except during startup and shutdown.
+ If the unit(s) no longer meets the requirement for LEE status, the unit(s) will comply by stack testing quarterly until a continuous monitoring system has been installed, certified, and is operating.

4. If the permittee uses the provisions for low emitting EGU (LEE) status for any pollutant except Hg, performance test data must be collected showing average emissions less than 50% the of the applicable standard. **(40 CFR 63.10005(h)(1)(i))**

II. MATERIAL LIMIT(S)

NA

III. PROCESS/OPERATIONAL RESTRICTION(S)

1. The permittee shall conduct a tune-up of each emission unit of FGMATS_U12 burner(s) and combustion controls, as applicable, at least every 36 calendar months, or each 48 calendar months if neural network combustion optimization software is employed, as specified in 40 CFR 63.10021(e). **(40 CFR 63.10000(e), 40 CFR 63.10006(i), 40 CFR 63.10021(e))**

2. For the startup of any emission unit of FGMATS_U12 which will comply using paragraph (1) of the definition of ''startup'' in 40 CFR 63.10042, the permittee must use clean fuels as defined in 40 CFR 63.10042 for ignition. Once the emission unit(s) of FGMATS_U12 convert(s) to firing coal, residual oil, or solid oil-derived fuel, the permittee must engage all the applicable control technologies except dry scrubber and SCR. The permittee must start the dry scrubber and SCR systems, if present, appropriately to comply with relevant standards applicable during normal operation. The permittee must comply with all applicable emission limits at all times except for periods that meet the applicable definitions of startup and shutdown in 40 CFR Part 63, Subpart UUUUU. **(40 CFR 63.10042, 40 CFR Part 63, Subpart UUUUU, Table 3)**

3. During shutdown of any emission unit of FGMATS_U12 while firing coal, residual oil, or solid oil-derived fuel, the permittee must vent emissions to the main stack(s) and operate all applicable control devices and continue to operate those control devices after the cessation of coal, residual oil, or solid oil-derived fuel being fed into the applicable emission unit(s) of FGMATS_U12 and for as long as possible thereafter considering operational and safety concerns. In any case, the permittee must operate their controls when necessary to comply with other standards made applicable to the FGMATS_U12 by a permit limit or a rule other than 40 CFR Part 63, Subpart UUUUU and that require operation of the control devices. If, in addition to the fuel used prior to initiation of shutdown, another fuel must be used to support the shutdown process, that additional fuel must be one or a combination of the clean fuels defined in 40 CFR 63.10042 and must be used to the maximum extent possible taking into account considerations such as not compromising boiler or control device integrity. **(40 CFR 63.10042, 40 CFR Part 63, Subpart UUUUU, Table 3)**

4. The emission limits and operating limits in 40 CFR Part 63, Subpart UUUUU apply at all times except during periods of startup and shutdown; however, the applicable work practice requirements, which are specified in items 3 and 4 of Table 3 of 40 CFR Part 63, Subpart UUUUU must be met during periods of startup or shutdown. **(40 CFR 63.10000(a), 40 CFR Part 63, Subpart UUUUU, Table 3, 40 CFR 63.10022(a)(4))**

IV. DESIGN/EQUIPMENT PARAMETER(S)

1. The permittee shall operate and maintain all associated air pollution control equipment and monitoring equipment necessary for compliance with 40 CFR Part 63, Subpart UUUUU in a manner consistent with safety and good air pollution control practices for minimizing emissions. **(40 CFR 63.10000(b))**

V. TESTING/SAMPLING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. The permittee shall verify the filterable PM emission rates from each emission unit by testing at owner's expense, in accordance with 40 CFR 63.10007 and Table 5 to 40 CFR Part 63, Subpart UUUUU. The permittee must complete the test once every calendar quarter and at least 45 days since the previous performance test if not a LEE for PM. The permittee may skip performance testing in those quarters during which less than 168 boiler operating hours occur, except that a performance test must be conducted at least once every calendar year. **(40 CFR 63.10006(f), 40 CFR 63.10007, 40 CFR 63.10021(d)(1) and (2), 40 CFR Part 63, Subpart UUUUU, Table 5)**

2. The permittee shall verify the HCl emission rates from each emission unit by testing at owner's expense, in accordance with 40 CFR 63.10007 and Table 5 to 40 CFR Part 63, Subpart UUUUU. The permittee must complete the test once every calendar quarter and at least 45 days since the previous performance test if not a LEE for HCl. The permittee may skip performance testing in those quarters during which less than 168 boiler operating hours occur, except that a performance test must be conducted at least once every calendar year. **(40 CFR 63.10006(f), 40 CFR 63.10007, 40 CFR 63.10021(d)(1) and (2), 40 CFR Part 63, Subpart UUUUU, Table 5)**

3. If the permittee uses the provisions for LEE status for any pollutant except for Hg, the permittee shall verify each LEE pollutant emission rate from the applicable emission unit(s) of FGMATS_U12 by testing at owner's expense, in accordance with 40 CFR 63.10007 and Table 5 to 40 CFR Part 63, Subpart UUUUU. The permittee must complete the test once every 36 months and at least 1,050 days since the previous performance test to demonstrate continued LEE status. If a performance test deadline is missed due to the EGU being inoperative and 168 or more boiler operating hours occur in the next test period, an additional performance test shall be completed in the next test period, with at least 350 calendar days separating the performance tests conducted in the same 3-year period. **(40 CFR 63.10006(b), 40 CFR 63.10006(f), 40 CFR 63.10007, 40 CFR Part 63, Subpart UUUUU, Table 5)**

4. Unless an alternate schedule has been approved by the AQD, no less than 30 days prior to testing, the permittee shall submit a complete test plan to the AQD Technical Programs Unit and District Office. The AQD must approve the final plan prior to testing. The protocol shall describe the test method(s) and the maximum routine operating conditions, including targets for key operational parameters associated with air pollution control equipment to be monitored and recorded during testing, as applicable. **(40 CFR 63.7, 40 CFR 63.10007, 40 CFR 63.10030(a))**

VI. MONITORING/RECORDKEEPING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. During startup, as defined by paragraph (1) of the definition of "startup" in 40 CFR 63.10042, the permittee must operate all Continuous Monitoring Systems (CMS). Startup means either the first-ever firing of fuel in a boiler for the purpose of producing electricity, or the firing of fuel in a boiler after a shutdown event for any purpose. Startup ends when any of the steam from the boiler is used to generate electricity for sale over the grid or for any other purpose (including on site use). The permittee must comply with the applicable emission limits at all times except for startup and shutdown periods unless the permittee chooses to use just one set of sorbent traps to demonstrate compliance with the applicable Hg emission limit, then the permittee must comply with the applicable Hg emission limit at all times. The permittee must collect monitoring data during startup periods, as specified in 40 CFR 63.10020(a) and (b). The permittee must keep records during startup periods, as provided in 40 CFR 63.10032 and 40 CFR 63.10021(h). Any fraction of an hour in which startup occurs constitutes a full hour of startup. **(40 CFR Part 63, Subpart UUUUU, Table 3)**

2. The permittee must operate all CMS during shutdown. The permittee must also collect appropriate data, and the permittee must calculate the pollutant emission rate for each hour of shutdown for those pollutants for which a CMS is used. The permittee must collect monitoring data during shutdown periods, as specified in 40 CFR 63.10020(a). The permittee must keep records during shutdown periods, as provided in 40 CFR 63.10032 and 40 CFR 63.10021(h). Any fraction of an hour in which shutdown occurs constitutes a full hour of shutdown. **(40 CFR Part 63, Subpart UUUUU, Table 3)**

3. For any emission unit not relying on the LEE provisions for Hg, the permittee shall install, calibrate, maintain and operate a device to monitor and record the Hg concentration from each emission unit on a continuous basis. The permittee shall install and operate the Hg CEMS or sorbent trap monitoring system to meet the timelines, requirements and reporting detailed in Appendix A of 40 CFR Part 63, Subpart UUUUU. **(40 CFR 63.10000(c)(1)(vi))**

4. If required to convert measured pollutant concentrations to the units of the applicable mass per heat input emission limit(s) or for routine operation of a sorbent trap monitoring system, the permittee shall install, calibrate, maintain and operate a device to monitor and record the oxygen (O_2) or carbon dioxide (CO_2) exhaust gas content, exhaust gas flow rate and/or moisture from each emission unit on a continuous basis. The monitor shall be operated in accordance with procedures outlined in 40 CFR Part 75, Appendices A and B. As an alternative

to moisture monitoring, the permittee may elect to use appropriate fuel-specific default moisture values from 40 CFR 75.11(b) for coal-fired units or a default moisture value for non-coal-fired units as established via petition to the Administrator under 40 CFR 75.66. **(40 CFR 63.10010(b)-(d), 40 CFR Part 63, Subpart UUUUU, Table 5)**

5. For any emission unit not relying on the LEE provisions for Hg, the permittee shall keep, in a satisfactory manner, hourly (if applicable) and 30-day rolling average Hg emission rate records for each emission unit **OR** (30-day (or 90-day if emission averaging (as applicable)) rolling weighted average Hg emission rate records for the combination of units participating in an averaging plan) excluding periods of startup and shutdown. **(40 CFR 63.10010, 40 CFR 63.10021, 40 CFR Part 63, Subpart UUUUU, Table 7)**

6. The permittee must operate the required monitoring system(s) and collect data at all required intervals at all times that the affected EGU is operating, except for periods of monitoring system malfunctions or out-of-control periods (see 40 CFR 63.8(c)(7) of 40 CFR Part 63, Subpart A), and required monitoring system quality assurance or quality control activities, including, as applicable, calibration checks and required zero and span adjustments. The permittee is required to affect monitoring system repairs in response to monitoring system malfunctions and to return the monitoring system to operation as expeditiously as practicable. **(40 CFR 63.10020(b))**

7. The permittee may not use data recorded during startup or shutdown in calculations used to report emissions, except as otherwise provided in 40 CFR 63.10000(c)(1)(vi)(B) and 40 CFR 63.10005(a)(2)(iii). In addition, data recorded during monitoring system malfunctions or monitoring system out-of-control periods, repairs associated with monitoring system malfunctions or monitoring system out-of-control periods or required monitoring system quality assurance or control activities may not be used in calculations used to report emissions or operating levels. The permittee must use all of the quality-assured data collected during all other periods in assessing the operation of the control device and associated control system. **(40 CFR 63.10020(c))**

8. Failure to collect required data is a deviation from the monitoring requirements except for periods of monitoring system malfunctions or monitoring system out-of-control periods, repairs associated with monitoring system malfunctions or monitoring system out-of-control periods and required monitoring system quality assurance or quality control activities including, as applicable, calibration checks and required zero and span adjustments. **(40 CFR 63.10020(d))**

9. If the permittee uses CEMS to measure SO_2, PM, HCl, HF, or Hg emissions (or sorbent trap monitoring system), except as otherwise provided in 40 CFR 63.10020(c), the permittee must demonstrate continuous compliance by using all quality-assured hourly data recorded by the CEMS (or sorbent trap monitoring system) and other required monitoring systems to calculate the arithmetic average emissions rate in units of the standard on a continuous 30-boiler operating day (or, if alternate emissions averaging is used for Hg, a 90-boiler operating day) rolling average basis, updated at the end of each new boiler operating day. Use Equation 8 in 40 CFR 63.10021(b) to determine the 30- or 90-boiler operating day rolling average. **(40 CFR 63.10021(a) and (b))**

10. The permittee must keep the following records:

    a. A copy of each notification and report that has been submitted to comply with 40 CFR Part 63, Subpart UUUUU, including all documentation supporting any Initial Notification or Notification of Compliance Status or semiannual compliance report that has been submitted, according to the requirements in 40 CFR 63.10(b)(2)(xiv). **(40 CFR 63.10032(a)(1))**

    b. Records of performance stack tests, fuel analyses, or other compliance demonstrations and performance evaluations, as required in 40 CFR 63.10(b)(2)(viii). **(40 CFR 63.10032(a)(2))**

    c. For each CEMS and CPMS, the permittee must keep the following records:

        i. Records described in 40 CFR 63.10(b)(2)(vi) through (xi). **(40 CFR 63.10032(b)(1))**

        ii. Previous (i.e., superseded) versions of the performance evaluation plan as required in 40 CFR 63.8(d)(3). **(40 CFR 63.10032(b)(2))**

        iii. Request for alternatives to relative accuracy test for CEMS as required in 40 CFR 63.8(f)(6)(i). **(40 CFR 63.10032(b)(3))**

        iv. The date and time that each deviation started and stopped and whether the deviation occurred during a period of startup, shutdown, or malfunction or during another period. **(40 CFR 63.10032(b)(4))**

v. If the permittee continuously monitors Hg and/or HCl and/or HF emissions, the permittee must also keep the records required under Appendix A and/or Appendix B of 40 CFR Part 63, Subpart UUUUU. **(40 CFR 63.10032(a))**

d. For each emission unit subject to an emission limit:

i. The permittee shall keep the monthly fuel use by each emission unit, including the type(s) of fuel and amount(s) used. **(40 CFR 63.10032(d)(1))**

ii. If the permittee combusts non-hazardous secondary materials that have been determined not to be solid waste pursuant to 40 CFR 241.3(b)(1), the permittee must keep a record which documents how the secondary material meets each of the legitimacy criteria. If the permittee combusts a fuel that has been processed from a discarded non-hazardous secondary material pursuant to 40 CFR 241.3(b)(2), the permittee must keep records as to how the operations that produced the fuel satisfies the definition of processing in 40 CFR 241.2. If the fuel received a non-waste determination pursuant to the petition process submitted under 40 CFR 241.3(c), the permittee must keep a record which documents how the fuel satisfies the requirements of the petition process. **(40 CFR 63.10032(d)(2))**

iii. For an emission unit that qualifies as a LEE under 40 CFR 63.10005(h), the permittee shall keep annual records that document that the emissions in the previous stack test(s) continue to qualify the unit for LEE status for an applicable pollutant, and document that there was no change in source operations including fuel composition and operation of air pollution control equipment that would cause emissions of the pollutant to increase within the past year. **(40 CFR 63.10032(d)(3))**

e. Regarding startup periods or shutdown periods:

i. If the permittee chooses to rely on paragraph (1) of the definition of ''startup'' in 40 CFR 63.10042 for the emission unit(s), the permittee shall keep records of the occurrence and duration of each startup or shutdown. **(40 CFR 63.10032(f)(1))**

ii. The type(s) and amount(s) of fuel used during each startup or shutdown. **(40 CFR 63.10032(i))**

f. The occurrence and duration of each malfunction of an operation (i.e., process equipment) or the air pollution control and monitoring equipment. **(40 CFR 63.10032(g))**

g. Actions taken during periods of malfunction to minimize emissions in accordance with 40 CFR 63.10000(b), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation. **(40 CFR 63.10032(h))**

h. If the permittee elects to average emissions consistent with 40 CFR 63.10009, the permittee shall keep a copy of the emissions averaging implementation plan required in 40 CFR 63.10009(g), all calculations required under 40 CFR 63.10009, including daily records of heat input or steam generation, as applicable, and monitoring records consistent with 40 CFR 63.10022. **(40 CFR 63.10032(e))**

11. The permittee shall keep all records in a form suitable and readily available for expeditious review and for at least 5 years after the date of each occurrence, corrective action, report, or record. The records must be kept onsite for at least 2 years and may be kept offsite for the remaining 3 years. **(40 CFR 63.10(b)(1), 40 CFR 63.10033)**

12. The permittee shall maintain on site and submit, if requested by the Administrator, an annual report of periodic performance tune-ups containing the information required by 40 CFR 63.10021(e)(8). The reports shall be in a format acceptable to the Administrator. If requested by the AQD District Supervisor, the permittee shall also submit an annual report with the results of the performance tune-ups. **(40 CFR 63.10021(e)(8))**

VII. REPORTING

1. Prompt reporting of deviations pursuant to General Conditions 21 and 22 of Part A. **(R 336.1213(3)(c)(ii))**

2. Semiannual reporting of monitoring and deviations pursuant to General Condition 23 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for reporting period July 1 to December 31 and September 15 for reporting period January 1 to June 30. **(R 336.1213(3)(c)(i))**

3. Annual certification of compliance pursuant to General Conditions 19 and 20 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for the previous calendar year. **(R 336.1213(4)(c))**

4. Semiannual reporting of the information required in 40 CFR 63.10031(c)(1) through (9), (d), and (e) as applicable. The report shall be postmarked or received by the Administrator by March 15 for reporting period July 1 to December 31 and September 15 for reporting period January 1 to June 30. The report shall include the following:

   a. The information required by the Continuous Monitoring Summary Report located in 40 CFR 63.10(e)(3)(vi). **(40 CFR 63.10031(c)(1))**

   b. The total fuel use by each affected source subject to an emission limit, for each calendar month within the semiannual reporting period, including, but not limited to, a description of the fuel, whether the fuel has received a non-waste determination by USEPA or the basis for concluding that the fuel is not a waste, and the total fuel usage amount with units of measure. **(40 CFR 63.10031(c)(2))**

   c. Indicate whether any emission unit in FGMATS_U12 burned new types of fuel during the reporting period. If new types of fuel were burned, include the date of the performance test where that fuel was in use. **(40 CFR 63.10031(c)(3))**

   d. Include the date of the most recent tune-up for each emission unit. The date of the tune-up is the date the tune-up provisions specified in 40 CFR 63.10021(e)(6) and (7) were completed. **(40 CFR 63.10031(c)(4))**

   e. Report emergency bypass information annually from units with LEE status. **(40 CFR 63.10031(c)(6))**

   f. A summary of the results of the annual performance tests and documentation of any operating limits that were reestablished during the test, if applicable. If the permittee is conducting stack tests once every 3 years to maintain LEE status, consistent with 40 CFR 63.10006(b), the report shall include the date of each stack test conducted during the previous 3 years, a comparison of emission level the permittee achieved in each stack test conducted during the previous 3 years to the 50% emission limit threshold required in 40 CFR 63.10005(h)(1)(i), and a statement as to whether there have been any operational changes since the last stack test that could increase emissions. **(40 CFR 63.10031(c)(7))**

   g. If there are no deviations from any emission limitation (emission limit and operating limit) that applies to FGMATS_U12 and there are no deviations from the requirements for work practice standards in Table 3 to 40 CFR Part 63, Subpart UUUUU that apply to FGMATS_U12, the report shall include a statement that there were no deviations from the emission limitations and work practice standards during the reporting period. If there were no periods during which the CMSs, including continuous emissions monitoring system, and operating parameter monitoring systems, were out-of-control as specified in 40 CFR 63.8(c)(7), a statement that there were no periods during which the CMSs were out-of-control during the reporting period. **(40 CFR Part 63, Subpart UUUUU, Table 8)**

   h. If there is a deviation from any emission limitation (emission limit and operating limit) or work practice standard during the reporting period, the report must contain a brief description of the deviation, the duration of the deviation, the cause of the deviation, and the information in 40 CFR 63.10031(d). If there were periods during which the CMS's, including continuous emissions monitoring systems and continuous parameter monitoring systems, were out-of-control, as specified in 40 CFR 63.8(c)(7), the report must contain the information in 40 CFR 63.10031(e). **(40 CFR 63.10031(c)(1) through (9), (d), and (e), 40 CFR 63.10031(a), 40 CFR 63.10031(c)(9), 40 CFR Part 63, Subpart UUUUU, Table 8)**

   i. If the affected source submits a compliance report pursuant to Table 8 in 40 CFR Part 63, Subpart UUUUU, or as part of, the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), and the compliance report includes all required information concerning deviations from any emission limit, operating limit, or work practice requirement in 40 CFR Part 63, Subpart UUUUU, submission of the compliance report satisfies any obligation to report the same deviations in the semiannual monitoring report required by SC VII.2. **(40 CFR 63.10031(e))**

5. The permittee must submit any of the following applicable notifications by the dates specified within the specific citation: 40 CFR 63.7(b) and (c) Notification of performance test and Quality assurance program; 40 CFR 63.8(e) Performance evaluation of continuous monitoring systems; 40 CFR 63.8(f)(4) Request to use alternative monitoring methods; 40 CFR 63.8(f)(6) Alternative to the relative accuracy test; 40 CFR 63.9(b) Initial

notifications; 40 CFR 63.9(c) Request for extension of compliance; 40 CFR 63.9(d) Notification that source is subject to special compliance requirements; 40 CFR 63.9(e) Notification of performance test, which shall be submitted at least 30 days before the performance test is scheduled to begin; 40 CFR 63.9(f) Notification of opacity and visible emission observations; 40 CFR 63.9(g) Additional notification requirements for sources with continuous monitoring systems; and 40 CFR 63.9(h) Notification of compliance status. **(40 CFR 63.10030(a))**

6. On or after July 1, 2020, within 60 days after the date of completing each performance test, the permittee must submit the performance test reports required by this subpart to USEPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through USEPA's Central Data Exchange (CDX) (www.epa.gov/cdx). Performance test data must be submitted in the file format generated through use of USEPA's Electronic Reporting Tool (ERT) (see http://www.epa.gov/ttn/chief/ert/index.html). Only data collected using those test methods on the ERT Web site are subject to this requirement for submitting reports electronically to WebFIRE. At the discretion of the AQD, the permittee must also submit these reports, one to the Technical Programs Unit Supervisor and one to the AQD District Supervisor, in a format approved by the AQD. **(40 CFR 63.10031(f))**

7. On or after July 1, 2020, within 60 days after the date of completing each CEMS (SO2, PM, HCl, HF, and Hg) performance evaluation test, as defined in 40 CFR 63.2, the permittee must submit the relative accuracy test audit (RATA) data (or, for PM CEMS, RCA and RRA data) required by this subpart to USEPA's WebFIRE database by using CEDRI that is accessed through USEPA's CDX (www.epa.gov/cdx). The RATA data shall be submitted in the file format generated through use of USEPA's Electronic Reporting Tool (ERT) (http://www.epa.gov/ttn/chief/ert/index.html). Only RATA data compounds listed on the ERT Web site are subject to this requirement. At the discretion of the AQD, the permittee must also submit these RATA reports to the AQD District Supervisor in a format approved by the AQD. Owners or operators shall submit calibration error testing, drift checks, and other information required in the performance evaluation as described in 40 CFR 63.2 and as required in this chapter. **(40 CFR 63.10031(f)(1))**

8. On or after July 1, 2020, for a PM CEMS, PM CPMS, or approved alternative monitoring using a HAP metals CEMS, within 60 days after the reporting periods ending on March 31, June 30, September 30, and December 31, the permittee must submit quarterly reports to USEPA's WebFIRE database by using the CEDRI that is accessed through USEPA's CDX (www.epa.gov/cdx). The permittee must use the appropriate electronic reporting form in CEDRI or provide an alternate electronic file consistent with USEPA's reporting form output format. For each reporting period, the quarterly reports must include all of the calculated 30-boiler operating day rolling average values derived from the CEMS and PM CPMS. **(40 CFR 63.10031(f)(2))**

9. Reports for a SO_2 CEMS, a Hg CEMS or sorbent trap monitoring system, a HCl or HF CEMS, and any supporting monitors for such systems (such as a diluent or moisture monitor) shall be submitted using the ECMPS Client Tool, as provided for in 40 CFR Part 63, Subpart UUUUU, Appendices A and B and 40 CFR 63.10021(f). **(40 CFR 63.10031(f)(3))**

10. On or after July 1, 2020, the permittee must submit all reports required by 40 CFR 63.10031 (c) and (d) electronically using CEDRI that is accessed through the USEPA's Central Data Exchange (CDX) (www.epa.gov/cdx). The permittee must use the appropriate electronic reporting form in CEDRI or provide an alternate electronic file consistent with USEPA's reporting form output format. If requested by the AQD, the permittee must also submit these reports to the AQD District Supervisor in a format approved by the AQD. **(40 CFR 63.10031(f)(4))**

11. Prior to July 1, 2020, all reports subject to electronic submittal in SC VII.6, VII.7, VII.8 and VII.10 shall be submitted to the USEPA at the frequency specified in those paragraphs in electronic portable document format (PDF) using the ECMPS Client Tool. Each PDF version of a submitted report must include sufficient information to assess compliance and to demonstrate that the testing was done properly. The data elements listed at 40 CFR 63.10031(f)(6)(i)-(xii) must be entered into the ECMPS Client Tool at the time of submission of each PDF file. **(40 CFR 63.10031(f)(6))**

12. If requested by the Administrator, the permittee must submit the monitoring plan (or relevant portion of the plan) at least 60 days before the initial performance evaluation of a particular CMS, except where the CMS has already

undergone a performance evaluation that meets the requirements of 40 CFR 63.10010 (e.g., if the CMS was previously certified under another program). **(40 CFR 63.10000(d)(3))**

See Appendix 8

VIII. STACK/VENT RESTRICTION(S)

NA

IX. OTHER REQUIREMENT(S)

1. For each emission unit or emissions averaging group complying with an emission limit as specified in Table 2 of 40 CFR Part 63, Subpart UUUUU, the permittee may request to switch from a mass per heat input to a mass per gross output limit (or vice versa).
   a. The permittee may switch from a mass per heat input to a mass per gross output limit (or vice-versa), provided that:
      i. The permittee submits a request that identifies for each emission unit or emissions averaging group involved in the proposed switch both the current and proposed emission limit. **(40 CFR 63.10030(e)(7)(iii)(A)(1))**
      ii. The request arrives to the Administrator at least 30 calendar days prior to the date that the switch is proposed to occur. **(40 CFR 63.10030(e)(7)(iii)(A)(2))**
      iii. The request demonstrates through performance stack test results completed within 30 days prior to the submission, compliance for each emission unit or emissions averaging group with both the mass per heat input and mass per gross output limits. **(40 CFR 63.10030(e)(7)(iii)(A)(3))**
      iv. The permittee revises and submits all other applicable plans, e.g., monitoring and emissions averaging, with the request. **(40 CFR 63.10030(e)(7)(iii)(A)(4))**
      v. The permittee maintains records of all information regarding the choice of emission limits. **(40 CFR 63.10030(e)(7)(iii)(A)(5))**
   b. The permittee may begin to use the revised emission limits starting in the next reporting period, after receipt of written acknowledgement from the Administrator of the switch. **(40 CFR 63.10030(e)(7)(iii)(B))**
   c. From the submission of the request until start of the next reporting period after receipt of written acknowledgement from the Administrator of the switch, the permittee shall demonstrate compliance with both the mass per heat input and mass per gross output emission limits for each pollutant for each emission unit or emissions averaging group. **(40 CFR 63.10030(e)(7)(iii)(C))**

2. If using a CMS to demonstrate continuous compliance with an emission limit or operating limit, the permittee must develop a site-specific monitoring plan and submit this site-specific monitoring plan, if requested, at least 60 days before the initial performance evaluation (where applicable) of the CMS. This requirement also applies to the permittee if the permittee petitions the Administrator for alternative monitoring parameters under 40 CFR 63.8(f). This requirement to develop and submit a site-specific monitoring plan does not apply to affected sources with existing monitoring plans that apply to CEMS and CPMS prepared under Appendix B of 40 CFR Part 60 or 40 CFR Part 75, and that meet the requirements of 40 CFR 63.10010. Using the process described in 40 CFR 63.8(f)(4), the permittee may request approval of monitoring system quality assurance and quality control procedures alternative to those specified in this paragraph of this section and, if approved, include those in the site-specific monitoring plan. The monitoring plan must address the following provisions: **(40 CFR 63.10000(d), 40 CFR 63.10010)**
   a. Installation of the CMS or sorbent trap monitoring system sampling probe or other interface at a measurement location relative to each affected process unit such that the measurement is representative of control of the exhaust emissions (e.g., on or downstream of the last control device). See 40 CFR 63.10010(a) for further details. For PM CPMS installations, follow the procedures in 40 CFR 63.10010(h).

b. Performance and equipment specifications for the sample interface, the pollutant concentration or parametric signal analyzer, and the data collection and reduction systems.

c. Schedule for conducting initial and periodic performance evaluations.

d. Performance evaluation procedures and acceptance criteria (e.g., calibrations), including the quality control program in accordance with the general requirements of 40 CFR 63.8(d).

e. On-going operation and maintenance procedures, in accordance with the general requirements of 40 CFR 63.8(c)(1)(ii), (c)(3), and (c)(4)(ii).

f. Conditions that define a CMS that is out of control consistent with 40 CFR 63.8(c)(7)(i) and for responding to out of control periods consistent with 40 CFR 63.8(c)(7)(ii) and (c)(8).

g. On-going recordkeeping and reporting procedures, in accordance with the general requirements of 40 CFR 63.10(c), (e)(1), and (e)(2)(i), or as specifically required under 40 CFR Part 63, Subpart UUUUU.

h. Alternatively, the requirements are considered to be met for a particular CMS or sorbent trap monitoring system if:

   i. The CMS or sorbent trap monitoring system is installed, certified, maintained, operated, and quality-assured either according to 40 CFR Part 75, or Appendix A or B of 40 CFR Part 63, Subpart UUUUU; and

   ii. The recordkeeping and reporting requirements of 40 CFR Part 75, or Appendix A or B of 40 CFR Part 63, Subpart UUUUU, which pertain to the CMS, are met.

3. If the permittee chooses to reapply for LEE status, the permittee must demonstrate all performance tests and CEMS or sorbent trap monitoring system data over a consecutive 3-year period show compliance with the LEE criteria. **(40 CFR 63.10006(b)(2) and (h))**

4. If any emission unit(s) cease(s) to operate in a manner that causes the unit(s) to meet the definition of an EGU subject to 40 CFR Part 63, Subpart UUUUU, the permittee must submit the notification in 40 CFR 63.10000(i)(2) no less than 30 days prior to when the EGU will cease complying with 40 CFR Part 63, Subpart UUUUU. **(40 CFR 63.10000(i)(2), 40 CFR 63.10030(f))**

5. The permittee shall comply with all provisions of the National Emission Standards for Hazardous Air Pollutants as specified in 40 CFR Part 63, Subparts A and UUUUU. **(40 CFR Part 63, Subparts A and UUUUU)**

Footnotes:
[1] This condition is state only enforceable and was established pursuant to Rule 201(1)(b).
[2] This condition is federally enforceable and was established pursuant to Rule 201(1)(a).

FGMATS_U3
FLEXIBLE GROUP CONDITIONS

DESCRIPTION

40 CFR Part 63, Subpart UUUUU (Mercury and Air Toxics Standards or MATS) requirements for existing coal-fired electric utility steam generating unit(s) (EGU) rated more than 25 megawatts electric (MWe) that serve(s) a generator producing electricity for sale and designed to burn coal that is not low rank virgin coal (calorific value of ≥ 8,300 BTU/pound).

Emission Unit: EUBOILER3

POLLUTION CONTROL EQUIPMENT

Low-NOx burners,
Selective catalytic reduction (SCR),
Sorbent injection (ACI) (activated carbon or other sorbent for mercury control),
Spray dry absorber (SDA) for acid gas control,
Pulse-jet fabric filter (PJFF) baghouse for PM control.

I. EMISSION LIMIT(S)

Pollutant	Limit	Time Period/ Operating Scenario	Equipment	Monitoring/ Testing Method	Underlying Applicable Requirements
1. Filterable PM	0.030 lb/MMBTU*	30-day boiler operating day rolling arithmetic average updated at the end of each new boiler operating day	EUBOILER3	SC VI.3 SC VI.7 SC VI.8	**40 CFR 63.9991 40 CFR Part 63, Subpart UUUUU, Table 2.1.a**
2. SO_2	0.20 lb/MMBTU*	30-boiler operating day rolling arithmetic average updated at the end of each new boiler operating day	EUBOILER3	SC VI.2 SC VI.6 SC VI.7 SC VI.10 SC VI.14	**40 CFR 63.9991 40 CFR Part 63, Subpart UUUUU, Table 2.1.b**
3. Mercury (Hg)	1.2 lb/TBTU*	30-boiler operating day rolling arithmetic average updated at the end of each new boiler operating day	EUBOILER3	SC V.1 SC VI.4 SC VI.7 SC VI.9 SC VI.14	**40 CFR 63.9991 40 CFR Part 63, Subpart UUUUU, Table 2.1.c**

* The emission limits apply at all times except during startup and shutdown

II. MATERIAL LIMIT(S)

NA

III. PROCESS/OPERATIONAL RESTRICTION(S)

1. The permittee shall conduct a tune-up of each emission unit of FGMATS_U3 burner(s) and combustion controls, as applicable, at least every 36 calendar months, or each 48 calendar months if neural network combustion

optimization software is employed, as specified in 40 CFR 63.10021(e). **(40 CFR 63.10000(e), 40 CFR 63.10006(i), 40 CFR 63.10021(e))**

2. For the startup of any emission unit of FGMATS_U3 which will comply using paragraph (1) of the definition of ''startup'' in 40 CFR 63.10042, the permittee must use clean fuels as defined in 40 CFR 63.10042 for ignition. Once the emission unit(s) of FGMATS_U3 convert(s) to firing coal, residual oil, or solid oil-derived fuel, the permittee must engage all the applicable control technologies except dry scrubber and SCR. The permittee must start the dry scrubber and SCR systems, if present, appropriately to comply with relevant standards applicable during normal operation. The permittee must comply with all applicable emission limits at all times except for periods that meet the applicable definitions of startup and shutdown in 40 CFR Part 63, Subpart UUUUU. **(40 CFR 63.10042, 40 CFR Part 63, Subpart UUUUU, Table 3)**

3. During shutdown of any emission unit of FGMATS_U3 while firing coal, residual oil, or solid oil-derived fuel, the permittee must vent emissions to the main stack(s) and operate all applicable control devices and continue to operate those control devices after the cessation of coal, residual oil, or solid oil-derived fuel being fed into the applicable emission unit(s) of FGMATS_U3 and for as long as possible thereafter considering operational and safety concerns. In any case, the permittee must operate their controls when necessary to comply with other standards made applicable to the FGMATS_U3 by a permit limit or a rule other than 40 CFR Part 63, Subpart UUUUU and that require operation of the control devices. If, in addition to the fuel used prior to initiation of shutdown, another fuel must be used to support the shutdown process, that additional fuel must be one or a combination of the clean fuels defined in 40 CFR 63.10042 and must be used to the maximum extent possible taking into account considerations such as not compromising boiler or control device integrity. **(40 CFR 63.10042, 40 CFR Part 63, Subpart UUUUU, Table 3)**

4. The emission limits and operating limits in 40 CFR Part 63, Subpart UUUUU apply at all times except during periods of startup and shutdown; however, the applicable work practice requirements, which are specified in items 3 and 4 of Table 3 of 40 CFR Part 63, Subpart UUUUU must be met during periods of startup or shutdown. **(40 CFR 63.10000(a), 40 CFR Part 63, Subpart UUUUU, Table 3)**

IV. DESIGN/EQUIPMENT PARAMETER(S)

1. The permittee shall operate and maintain all associated air pollution control equipment and monitoring equipment necessary for compliance with 40 CFR Part 63, Subpart UUUUU in a manner consistent with safety and good air pollution control practices for minimizing emissions. **(40 CFR 63.10000(b))**

V. TESTING/SAMPLING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

NA

VI. MONITORING/RECORDKEEPING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. During startup, as defined by paragraph (1) of the definition of ''startup'' in 40 CFR 63.10042, the permittee must operate all Continuous Monitoring Systems (CMS). Startup means either the first-ever firing of fuel in a boiler for the purpose of producing electricity, or the firing of fuel in a boiler after a shutdown event for any purpose. Startup ends when any of the steam from the boiler is used to generate electricity for sale over the grid or for any other purpose (including on site use). The permittee must comply with the applicable emission limits at all times except for startup and shutdown periods unless the permittee chooses to use just one set of sorbent traps to demonstrate compliance with the applicable Hg emission limit, then the permittee must comply with the applicable Hg emission limit at all times. The permittee must collect monitoring data during startup periods, as specified in 40 CFR 63.10020(a) and (b). The permittee must keep records during startup periods, as provided in 40 CFR 63.10032 and 40 CFR 63.10021(h). Any fraction of an hour in which startup occurs constitutes a full hour of startup. **(40 CFR Part 63, Subpart UUUUU, Table 3)**

2. The permittee must operate all CMS during shutdown. The permittee must also collect appropriate data, and the permittee must calculate the pollutant emission rate for each hour of shutdown for those pollutants for which a CMS is used. The permittee must collect monitoring data during shutdown periods, as specified in 40 CFR 63.10020(a). The permittee must keep records during shutdown periods, as provided in 40 CFR 63.10032 and 40 CFR 63.10021(h). Any fraction of an hour in which shutdown occurs constitutes a full hour of shutdown. **(40 CFR Part 63, Subpart UUUUU, Table 3)**

3. The permittee shall install, calibrate, maintain and operate a device to monitor and record the PM concentration of the exhaust gas from each emission unit on a continuous basis. The permittee shall install and operate the PM CEMS to meet the timelines, requirements and reporting detailed in Performance Specification 11 in 40 CFR Part 60, Appendix B and Procedure 2 in 40 CFR Part 60, Appendix F. **(40 CFR 63.10010(i), 40 CFR Part 63, Subpart UUUUU, Table 5)**

4. The permittee shall install, calibrate, maintain and operate a device to monitor and record the Hg concentration from each emission unit on a continuous basis. The permittee shall install and operate the Hg CEMS or sorbent trap monitoring system to meet the timelines, requirements and reporting detailed in Appendix A of 40 CFR Part 63, Subpart UUUUU. **(40 CFR 63.10000(c)(1)(vi))**

5. The permittee shall install, maintain, and operate a device(s) to monitor and record the SO_2 concentration of the exhaust gas from each emission unit on a continuous basis. The permittee shall install and operate each CEMS to meet the timelines, requirements and reporting detailed in 40 CFR Part 75, Appendices A and B. **(40 CFR 63.10000(c)(1)(v))**

6. If required to convert measured pollutant concentrations to the units of the applicable mass per heat input emission limit(s) or for routine operation of a sorbent trap monitoring system, the permittee shall install, calibrate, maintain and operate a device to monitor and record the oxygen (O_2) or carbon dioxide (CO_2) exhaust gas content, exhaust gas flow rate and/or moisture from each emission unit on a continuous basis. The monitor shall be operated in accordance with procedures outlined in 40 CFR Part 75, Appendices A and B. As an alternative to moisture monitoring, the permittee may elect to use appropriate fuel-specific default moisture values from 40 CFR 75.11(b) for coal-fired units or a default moisture value for non-coal-fired units as established via petition to the Administrator under 40 CFR 75.66. **(40 CFR 63.10010(b)-(d), 40 CFR Part 63, Subpart UUUUU, Table 5)**

7. If the permittee elects to use a PM CEMS or participate in an averaging plan for PM, total non-Hg HAP metals, or individual metals, the permittee shall keep, in a satisfactory manner, hourly (if applicable) and 30-day rolling average PM, total non-Hg HAP metals, or individual metals (as applicable) emission rate records for each emission unit excluding periods of startup and shutdown. **(40 CFR 63.10010, 40 CFR 63.10021, 40 CFR Part 63, Subpart UUUUU, Table 7)**

8. For any emission unit not relying on the LEE provisions for Hg, the permittee shall keep, in a satisfactory manner, hourly (if applicable) and 30-day rolling average Hg emission rate records for each emission unit excluding periods of startup and shutdown. **(40 CFR 63.10010, 40 CFR 63.10021, 40 CFR Part 63, Subpart UUUUU, Table 7)**

9. The permittee shall keep, in a satisfactory manner, hourly and 30-day rolling average SO_2 emission rate records for each emission unit excluding periods of startup and shutdown. **(40 CFR 63.10010, 40 CFR 63.10021, 40 CFR Part 63, Subpart UUUUU, Table 7)**

10. The permittee must operate the required monitoring system(s) and collect data at all required intervals at all times that the affected EGU is operating, except for periods of monitoring system malfunctions or out-of-control periods (see 40 CFR 63.8(c)(7) of 40 CFR Part 63, Subpart A), and required monitoring system quality assurance or quality control activities, including, as applicable, calibration checks and required zero and span adjustments. The permittee is required to affect monitoring system repairs in response to monitoring system malfunctions and to return the monitoring system to operation as expeditiously as practicable. **(40 CFR 63.10020(b))**

11. The permittee may not use data recorded during startup or shutdown in calculations used to report emissions, except as otherwise provided in 40 CFR 63.10000(c)(1)(vi)(B) and 40 CFR 63.10005(a)(2)(iii). In addition, data recorded during monitoring system malfunctions or monitoring system out-of-control periods, repairs associated with monitoring system malfunctions or monitoring system out-of-control periods or required monitoring system quality assurance or control activities may not be used in calculations used to report emissions or operating levels. The permittee must use all of the quality-assured data collected during all other periods in assessing the operation of the control device and associated control system. **(40 CFR 63.10020(c))**

12. Failure to collect required data is a deviation from the monitoring requirements except for periods of monitoring system malfunctions or monitoring system out-of-control periods, repairs associated with monitoring system malfunctions or monitoring system out-of-control periods and required monitoring system quality assurance or quality control activities including, as applicable, calibration checks and required zero and span adjustments. **(40 CFR 63.10020(d))**

13. If the permittee uses CEMS to measure SO_2, PM, HCl, HF, or Hg emissions (or sorbent trap monitoring system), except as otherwise provided in 40 CFR 63.10020(c), the permittee must demonstrate continuous compliance by using all quality-assured hourly data recorded by the CEMS (or sorbent trap monitoring system) and other required monitoring systems to calculate the arithmetic average emissions rate in units of the standard on a continuous 30-boiler operating day (or, if alternate emissions averaging is used for Hg, a 90-boiler operating day) rolling average basis, updated at the end of each new boiler operating day. Use Equation 8 in 40 CFR 63.10021(b) to determine the 30- or 90-boiler operating day rolling average. **(40 CFR 63.10021(a) and (b))**

14. The permittee must keep the following records:

    a. A copy of each notification and report that has been submitted to comply with 40 CFR Part 63, Subpart UUUUU, including all documentation supporting any Initial Notification or Notification of Compliance Status or semiannual compliance report that has been submitted, according to the requirements in 40 CFR 63.10(b)(2)(xiv). **(40 CFR 63.10032(a)(1))**

    b. Records of performance stack tests, fuel analyses, or other compliance demonstrations and performance evaluations, as required in 40 CFR 63.10(b)(2)(viii). **(40 CFR 63.10032(a)(2))**

    c. For each CEMS and CPMS, the permittee must keep the following records:

        i. Records described in 40 CFR 63.10(b)(2)(vi) through (xi). **(40 CFR 63.10032(b)(1))**

        ii. Previous (i.e., superseded) versions of the performance evaluation plan as required in 40 CFR 63.8(d)(3). **(40 CFR 63.10032(b)(2))**

        iii. Request for alternatives to relative accuracy test for CEMS as required in 40 CFR 63.8(f)(6)(i). **(40 CFR 63.10032(b)(3))**

        iv. The date and time that each deviation started and stopped and whether the deviation occurred during a period of startup, shutdown, or malfunction or during another period. **(40 CFR 63.10032(b)(4))**

        v. If the permittee continuously monitors Hg and/or HCl and/or HF emissions, the permittee must also keep the records required under Appendix A and/or Appendix B of 40 CFR Part 63, Subpart UUUUU. **(40 CFR 63.10032(a))**

    d. For each emission unit subject to an emission limit:

        i. The permittee shall keep the monthly fuel use by each emission unit, including the type(s) of fuel and amount(s) used. **(40 CFR 63.10032(d)(1))**

        ii. If the permittee combusts non-hazardous secondary materials that have been determined not to be solid waste pursuant to 40 CFR 241.3(b)(1), the permittee must keep a record which documents how the secondary material meets each of the legitimacy criteria. If the permittee combusts a fuel that has been processed from a discarded non-hazardous secondary material pursuant to 40 CFR 241.3(b)(2), the permittee must keep records as to how the operations that produced the fuel satisfies the definition of processing in 40 CFR 241.2. If the fuel received a non-waste determination pursuant to the petition process submitted under 40 CFR 241.3(c), the permittee must keep a record which documents how the fuel satisfies the requirements of the petition process. **(40 CFR 63.10032(d)(2))**

e. Regarding startup periods or shutdown periods:

i. If the permittee chooses to rely on paragraph (1) of the definition of ''startup'' in 40 CFR 63.10042 for the emission unit(s), the permittee shall keep records of the occurrence and duration of each startup or shutdown. **(40 CFR 63.10032(f)(1))**

ii. The type(s) and amount(s) of fuel used during each startup or shutdown. **(40 CFR 63.10032(i))**

f. The occurrence and duration of each malfunction of an operation (i.e., process equipment) or the air pollution control and monitoring equipment. **(40 CFR 63.10032(g))**

g. Actions taken during periods of malfunction to minimize emissions in accordance with 40 CFR 63.10000(b), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation. **(40 CFR 63.10032(h))**

15. The permittee shall keep all records in a form suitable and readily available for expeditious review and for at least 5 years after the date of each occurrence, corrective action, report, or record. The records must be kept onsite for at least 2 years and may be kept offsite for the remaining 3 years. **(40 CFR 63.10(b)(1), 40 CFR 63.10033)**

16. The permittee shall maintain on site and submit, if requested by the Administrator, an annual report of periodic performance tune-ups containing the information required by 40 CFR 63.10021(e)(8). The reports shall be in a format acceptable to the Administrator. If requested by the AQD District Supervisor, the permittee shall also submit an annual report with the results of the performance tune-ups. **(40 CFR 63.10021(e)(8))**

VII. REPORTING

1. Prompt reporting of deviations pursuant to General Conditions 21 and 22 of Part A. **(R 336.1213(3)(c)(ii))**

2. Semiannual reporting of monitoring and deviations pursuant to General Condition 23 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for reporting period July 1 to December 31 and September 15 for reporting period January 1 to June 30. **(R 336.1213(3)(c)(i))**

3. Annual certification of compliance pursuant to General Conditions 19 and 20 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for the previous calendar year. **(R 336.1213(4)(c))**

4. Semiannual reporting of the information required in 40 CFR 63.10031(c)(1) through (9), (d), and (e) as applicable. The report shall be postmarked or received by the Administrator by March 15 for reporting period July 1 to December 31 and September 15 for reporting period January 1 to June 30. The report shall include the following:

a. The information required by the Continuous Monitoring Summary Report located in 40 CFR 63.10(e)(3)(vi). **(40 CFR 63.10031(c)(1))**

b. The total fuel use by each affected source subject to an emission limit, for each calendar month within the semiannual reporting period, including, but not limited to, a description of the fuel, whether the fuel has received a non-waste determination by USEPA or the basis for concluding that the fuel is not a waste, and the total fuel usage amount with units of measure. **(40 CFR 63.10031(c)(2))**

c. Indicate whether any emission unit in FGMATS_U3 burned new types of fuel during the reporting period. If new types of fuel were burned, include the date of the performance test where that fuel was in use. **(40 CFR 63.10031(c)(3))**

d. Include the date of the most recent tune-up for each emission unit. The date of the tune-up is the date the tune-up provisions specified in 40 CFR 63.10021(e)(6) and (7) were completed. **(40 CFR 63.10031(c)(4))**

e. If there are no deviations from any emission limitation (emission limit and operating limit) that applies to FGMATS_U3 and there are no deviations from the requirements for work practice standards in Table 3 to 40 CFR Part 63, Subpart UUUUU that apply to FGMATS_U3, the report shall include a statement that there were no deviations from the emission limitations and work practice standards during the reporting period. If there were no periods during which the CMSs, including continuous emissions monitoring system, and operating parameter monitoring systems, were out-of-control as specified in 40 CFR 63.8(c)(7), a statement

that there were no periods during which the CMSs were out-of-control during the reporting period. **(40 CFR Part 63, Subpart UUUUU, Table 8)**

f. If there is a deviation from any emission limitation (emission limit and operating limit) or work practice standard during the reporting period, the report must contain a brief description of the deviation, the duration of the deviation, the cause of the deviation, and the information in 40 CFR 63.10031(d). If there were periods during which the CMS's, including continuous emissions monitoring systems and continuous parameter monitoring systems, were out-of-control, as specified in 40 CFR 63.8(c)(7), the report must contain the information in 40 CFR 63.10031(e). **(40 CFR 63.10031(c)(1) through (9), (d), and (e), 40 CFR 63.10031(a), 40 CFR 63.10031(c)(9), 40 CFR Part 63, Subpart UUUUU, Table 8)**

g. If the affected source submits a compliance report pursuant to Table 8 in 40 CFR Part 63, Subpart UUUUU, or as part of, the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), and the compliance report includes all required information concerning deviations from any emission limit, operating limit, or work practice requirement in 40 CFR Part 63, Subpart UUUUU, submission of the compliance report satisfies any obligation to report the same deviations in the semiannual monitoring report required by SC VII.2. **(40 CFR 63.10031(e))**

5. The permittee must submit any of the following applicable notifications by the dates specified within the specific citation: 40 CFR 63.7(b) and (c) Notification of performance test and Quality assurance program; 40 CFR 63.8(e) Performance evaluation of continuous monitoring systems; 40 CFR 63.8(f)(4) Request to use alternative monitoring methods; 40 CFR 63.8(f)(6) Alternative to the relative accuracy test; 40 CFR 63.9(b) Initial notifications; 40 CFR 63.9(c) Request for extension of compliance; 40 CFR 63.9(d) Notification that source is subject to special compliance requirements; 40 CFR 63.9(e) Notification of performance test, which shall be submitted at least 30 days before the performance test is scheduled to begin; 40 CFR 63.9(f) Notification of opacity and visible emission observations; 40 CFR 63.9(g) Additional notification requirements for sources with continuous monitoring systems; and 40 CFR 63.9(h) Notification of compliance status. **(40 CFR 63.10030(a))**

6. On or after July 1, 2020, within 60 days after the date of completing each performance test, the permittee must submit the performance test reports required by this subpart to USEPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through USEPA's Central Data Exchange (CDX) (www.epa.gov/cdx). Performance test data must be submitted in the file format generated through use of USEPA's Electronic Reporting Tool (ERT) (see http://www.epa.gov/ttn/chief/ert/index.html). Only data collected using those test methods on the ERT Web site are subject to this requirement for submitting reports electronically to WebFIRE. At the discretion of the AQD, the permittee must also submit these reports, one to the Technical Programs Unit Supervisor and one to the AQD District Supervisor, in a format approved by the AQD. **(40 CFR 63.10031(f))**

7. On or after July 1, 2020, for a PM CEMS, PM CPMS, or approved alternative monitoring using a HAP metals CEMS, within 60 days after the reporting periods ending on March 31, June 30, September 30, and December 31, the permittee must submit quarterly reports to USEPA's WebFIRE database by using the CEDRI that is accessed through USEPA's CDX (www.epa.gov/cdx). The permittee must use the appropriate electronic reporting form in CEDRI or provide an alternate electronic file consistent with USEPA's reporting form output format. For each reporting period, the quarterly reports must include all of the calculated 30-boiler operating day rolling average values derived from the CEMS and PM CPMS. **(40 CFR 63.10031(f)(2))**

8. Reports for a SO_2 CEMS, a Hg CEMS or sorbent trap monitoring system, a HCl or HF CEMS, and any supporting monitors for such systems (such as a diluent or moisture monitor) shall be submitted using the ECMPS Client Tool, as provided for in 40 CFR Part 63, Subpart UUUUU, Appendices A and B and 40 CFR 63.10021(f). **(40 CFR 63.10031(f)(3))**

9. On or after July 1, 2020, the permittee must submit all reports required by 40 CFR 63.10031 (c) and (d) electronically using CEDRI that is accessed through the USEPA's Central Data Exchange (CDX) (www.epa.gov/cdx). The permittee must use the appropriate electronic reporting form in CEDRI or provide an alternate electronic file consistent with USEPA's reporting form output format. If requested by the AQD, the permittee must also submit these reports, to the AQD District Supervisor in a format approved by the AQD. **(40 CFR 63.10031(f)(4))**

10. Prior to July 1, 2020, all reports subject to electronic submittal in SC VII.6, VII.7, and VII.9 shall be submitted to the USEPA at the frequency specified in those paragraphs in electronic portable document format (PDF) using the ECMPS Client Tool. Each PDF version of a submitted report must include sufficient information to assess compliance and to demonstrate that the testing was done properly. The data elements listed at 40 CFR 63.10031(f)(6)(i)-(xii) must be entered into the ECMPS Client Tool at the time of submission of each PDF file. **(40 CFR 63.10031(f)(6))**

11. If requested by the Administrator, the permittee must submit the monitoring plan (or relevant portion of the plan) at least 60 days before the initial performance evaluation of a particular CMS, except where the CMS has already undergone a performance evaluation that meets the requirements of 40 CFR 63.10010 (e.g., if the CMS was previously certified under another program). **(40 CFR 63.10000(d)(3))**

VIII. STACK/VENT RESTRICTION(S)

NA

IX. OTHER REQUIREMENT(S)

1. For each emission unit or emissions averaging group complying with an emission limit as specified in Table 2 of 40 CFR Part 63, Subpart UUUUU, the permittee may request to switch from a mass per heat input to a mass per gross output limit (or vice versa).
   a. The permittee may switch from a mass per heat input to a mass per gross output limit (or vice-versa), provided that:
      i. The permittee submits a request that identifies for each emission unit or emissions averaging group involved in the proposed switch both the current and proposed emission limit. **(40 CFR 63.10030(e)(7)(iii)(A)(1))**
      ii. The request arrives to the Administrator at least 30 calendar days prior to the date that the switch is proposed to occur. **(40 CFR 63.10030(e)(7)(iii)(A)(2))**
      iii. The request demonstrates through performance stack test results completed within 30 days prior to the submission, compliance for each emission unit or emissions averaging group with both the mass per heat input and mass per gross output limits. **(40 CFR 63.10030(e)(7)(iii)(A)(3))**
      iv. The permittee revises and submits all other applicable plans, e.g., monitoring and emissions averaging, with the request. **(40 CFR 63.10030(e)(7)(iii)(A)(4))**
      v. The permittee maintains records of all information regarding the choice of emission limits. **(40 CFR 63.10030(e)(7)(iii)(A)(5))**
   b. The permittee may begin to use the revised emission limits starting in the next reporting period, after receipt of written acknowledgement from the Administrator of the switch. **(40 CFR 63.10030(e)(7)(iii)(B))**
   c. From the submission of the request until start of the next reporting period after receipt of written acknowledgement from the Administrator of the switch, the permittee shall demonstrate compliance with both the mass per heat input and mass per gross output emission limits for each pollutant for each emission unit or emissions averaging group. **(40 CFR 63.10030(e)(7)(iii)(C))**

2. If using a CMS to demonstrate continuous compliance with an emission limit or operating limit, the permittee must develop a site-specific monitoring plan and submit this site-specific monitoring plan, if requested, at least 60 days before the initial performance evaluation (where applicable) of the CMS. This requirement also applies to the permittee if the permittee petitions the Administrator for alternative monitoring parameters under 40 CFR 63.8(f). This requirement to develop and submit a site-specific monitoring plan does not apply to affected sources with existing monitoring plans that apply to CEMS and CPMS prepared under Appendix B of 40 CFR Part 60 or 40 CFR Part 75, and that meet the requirements of 40 CFR 63.10010. Using the process described in 40 CFR 63.8(f)(4), the permittee may request approval of monitoring system quality assurance and quality control procedures alternative to those specified in this paragraph of this section and, if approved, include those in the

site-specific monitoring plan. The monitoring plan must address the following provisions: **(40 CFR 63.10000(d), 40 CFR 63.10010)**

a. Installation of the CMS or sorbent trap monitoring system sampling probe or other interface at a measurement location relative to each affected process unit such that the measurement is representative of control of the exhaust emissions (e.g., on or downstream of the last control device). See 40 CFR 63.10010(a) for further details. For PM CPMS installations, follow the procedures in 40 CFR 63.10010(h).

b. Performance and equipment specifications for the sample interface, the pollutant concentration or parametric signal analyzer, and the data collection and reduction systems.

c. Schedule for conducting initial and periodic performance evaluations.

d. Performance evaluation procedures and acceptance criteria (e.g., calibrations), including the quality control program in accordance with the general requirements of 40 CFR 63.8(d).

e. On-going operation and maintenance procedures, in accordance with the general requirements of 40 CFR 63.8(c)(1)(ii), (c)(3), and (c)(4)(ii).

f. Conditions that define a CMS that is out of control consistent with 40 CFR 63.8(c)(7)(i) and for responding to out of control periods consistent with 40 CFR 63.8(c)(7)(ii) and (c)(8).

g. On-going recordkeeping and reporting procedures, in accordance with the general requirements of 40 CFR 63.10(c), (e)(1), and (e)(2)(i), or as specifically required under 40 CFR Part 63, Subpart UUUUU.

h. Alternatively, the requirements are considered to be met for a particular CMS or sorbent trap monitoring system if:

   i. The CMS or sorbent trap monitoring system is installed, certified, maintained, operated, and quality-assured either according to 40 CFR Part 75, or Appendix A or B of 40 CFR Part 63, Subpart UUUUU; and

   ii. The recordkeeping and reporting requirements of 40 CFR Part 75, or Appendix A or B of 40 CFR Part 63, Subpart UUUUU, which pertain to the CMS, are met.

3. If any emission unit(s) cease(s) to operate in a manner that causes the unit(s) to meet the definition of an EGU subject to 40 CFR Part 63, Subpart UUUUU, the permittee must submit the notification in 40 CFR 63.10000(i)(2) no less than 30 days prior to when the EGU will cease complying with 40 CFR Part 63, Subpart UUUUU. **(40 CFR 63.10000(i)(2), 40 CFR 63.10030(f))**

4. The permittee shall comply with all provisions of the National Emission Standards for Hazardous Air Pollutants as specified in 40 CFR Part 63, Subparts A and UUUUU. **(40 CFR Part 63, Subparts A and UUUUU)**

Footnotes:
[1] This condition is state only enforceable and was established pursuant to Rule 201(1)(b).
[2] This condition is federally enforceable and was established pursuant to Rule 201(1)(a).

FGEXISTINGRICE
FLEXIBLE GROUP CONDITIONS

DESCRIPTION

Existing Emergency Engines located at a Major Source < 500 HP, Commenced Construction or Reconstruction before June 12, 2006.

These four (4) existing stationary diesel-fired reciprocating compression ignition internal combustion engines are emergency generators subject to 40 CFR Part 63, Subpart ZZZZ (National Emission Standard for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines (RICE).

Emission Units: EUCATFIREPUMP3, EUHPHSWP15001, EUHPHSWP15002, EUHPHSWP3000.

POLLUTION CONTROL EQUIPMENT

NA

I. EMISSION LIMITS

NA

II. MATERIAL LIMIT(S)

Material	Limit	Time Period/ Operating Scenario	Equipment	Monitoring/ Testing Method	Underlying Applicable Requirements
1. Fuel Oil – sulfur content	1.0% by weight at 18,000 BTU/lb	Instantaneous; at all times	EUCATFIREPUMP3 EUHPHSWP15001 EUHPHSWP15002 EUHPHSWP3000	SC VI.5	**R 336.1401(1), Table 41**

III. PROCESS/OPERATIONAL RESTRICTION(S)

1. Each engine in FGEXISTINGRICE shall be installed, maintained, and operated in a satisfactory manner. A list of recommended work practice standards as specified in 40 CFR 63.6602 and Table 2c, Item 1 or the permittee may petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices. The following are the recommended work practices specified in 40 CFR Part 63, Subpart ZZZZ, Table 2c:

   a. Change oil and filter every 500 hours of operation or annually, whichever comes first, except as allowed in SC III.3.
   b. Inspect the air cleaner every 1,000 hours of operation or annually, whichever comes first; and replace as necessary.
   c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.

   If the emergency engine is being operated during an emergency and it is not possible to shut down the engine to perform the work practice standards on the schedule required the work practice standard can be delayed until the emergency is over. The work practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under Federal, State or local law has been abated. Sources must report any failure to perform the work practice on the schedule required and the Federal, State or local law or which the risk was deemed unacceptable. **(40 CFR 63.6602, 40 CFR Part 63, Subpart ZZZZ, Table 2c, Item 6)**

2. The permittee may utilize an oil analysis program in order to extend the specified oil change requirement. The oil analysis must be performed at the same frequency as oil changes are required. The oil analysis must be performed at the same frequency specified for changing the oil in Table 2c of 40 CFR Part 63, Subpart ZZZZ. **(40 CFR 63.6625(i))**

3. The permittee shall maintain and operate each engine in FGEXISTINGRICE per the manufacturer's emission related written instructions or develop a maintenance plan which must provide for the maintenance and operation of the engine in a manner consistent with good air pollution control practices for minimizing emissions. **(40 CFR 63.6625(e), 40 CFR 63.6640(a), 40 CFR Part 63, Subpart ZZZZ, Table 6 Item 9)**

4. The permittee shall minimize the time spent at idle during startup and minimize the startup time of each engine in FGEXISTINGRICE to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the emission standards applicable to all times other than startup apply. **(40 CFR 63.6625(h))**

5. There is no time limit on the use of emergency stationary RICE in emergency situations. **(40 CFR 63.6640(f)(1))**

6. The permittee may not operate each engine in FGEXISTINGRICE for more than 100 hours per calendar year for the purpose of necessary maintenance checks and readiness testing, provided that the tests are recommended by Federal, State, or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The permittee may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing. A petition is not required if the owner or operator maintains records indicating that Federal, State, or local standards require maintenance and testing of emergency internal combustion engines beyond 100 hours per calendar year. **(40 CFR 63.6640(f)(2))**

7. The permittee may operate each engine in FGEXISTINGRICE for up to 50 hours per calendar year in non-emergency situations, but those 50 hours are counted towards the 100 hours per calendar year provided for maintenance and testing as provided in 40 CFR 63.6640 (f)(2). The 50 hours per calendar year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income to supply non-emergency power as part of a financial arrangement with another entity, except as allowed in 40 CFR 63.6640(f)(4)(ii). **(40 CFR 63.6640(f)(4))**

8. If an emergency engine is operating during an emergency and it is not possible to shut down the engine in order to perform the work practice requirements on the schedule required in Table 2c of this subpart, or if performing the work practice on the required schedule would otherwise pose an unacceptable risk under Federal, State, or local law, the work practice can be delayed until the emergency is over or the unacceptable risk under Federal, State, or local law has abated. The work practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under Federal, State, or local law has abated. Sources must report any failure to perform the work practice on the schedule required and the Federal, State or local law under which the risk was deemed unacceptable. **(40 CFR Part 63, Table 2c, Footnote 1)**

IV. DESIGN/EQUIPMENT PARAMETER(S)

1. The permittee shall equip and maintain with a non-resettable hour meter to track the number of hours each engine operates. **(40 CFR 63.6625(f))**

V. TESTING/SAMPLING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. If using the oil analysis program in order to extend the specified oil change requirement in 40 CFR Part 63, Subpart ZZZZ, Table 2d, the permittee must at a minimum analyze the following three parameters: Total Base Number, viscosity, and percent water content. The condemning limits for these parameters are as follows Total Acid Number increases by more than 3.0 milligrams of potassium hydroxide (KOH) per gram from Total Acid Number of the oil when new; viscosity of the oil has changed by more than 20% from the viscosity of the oil when new; or percent water content (by volume) is greater than 0.5. If all of these condemning limits are not exceeded, the engine owner or operator is not required to change the oil. If any of the limits are exceeded, the engine owner

or operator must change the oil within 2 business days of receiving the results of the analysis; if the engine is not in operation when the results of the analysis are received, the engine owner or operator must change the oil within 2 business days or before commencing operation, whichever is later. The owner or operator must keep records of the parameters that are analyzed as part of the program, the results of the analysis, and the oil changes for the engine. The analysis program must be part of the maintenance plan for the engine. **(40 CFR 63.6625(j))**

See Appendix 5

VI. MONITORING/RECORDKEEPING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. For each engine in FGEXISTINGRICE, the permittee shall keep in a satisfactory manner, records of the occurrence and duration of each malfunction of operation or the air pollution control monitoring equipment. The permittee shall keep all records on file and make them available to the department upon request. **(40 CFR 63.6655(a)(2), 40 CFR 63.6660)**

2. For each engine in FGEXISTINGRICE, the permittee shall keep in a satisfactory manner, records of actions taken during periods of malfunction to minimize emissions, including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation. The permittee shall keep all records on file and make them available to the department upon request. **(40 CFR 63.6655(a)(5), 40 CFR 63.6660)**

3. For each engine in FGEXISITINGRICE, the permittee shall keep in a satisfactory manner, maintenance records to demonstrate compliance with SC III.1 and the written maintenance plan. The permittee shall keep all records on file and make them available to the department upon request. **(40 CFR 63.6655(d), 40 CFR 63.6655(e), 40 CFR 63.6660)**

4. The permittee shall monitor and record the total hours of operation for each engine in FGEXISTINGRICE per calendar year, recorded through the non-resettable hours meter, in a manner acceptable to the District Supervisor, Air Quality Division. The permittee shall document how many hours are spent for emergency operation; including what classified the operation as emergency and how many hours are spent for non-emergency operation. If the engine is used for the purposes specified in 40 CFR 63.6640(f)(4)(ii), the permittee must keep records of the notification of the emergency situation, and the date, start time, and end time of engine operation. **(40 CFR 63.6655(f))**

5. The permittee shall maintain sufficient records to demonstrate that the sulfur content for each shipment of fuel oil received is less than 1.0% by weight. **(R 336.1213(3))**

6. The permittee shall conduct and maintain records of a daily (non-certified) visual observation for opacity in order to verify proper firing, whenever an engine is in use for 24 consecutive hours or more. **(R 336.1213(3))**

7. The permittee shall maintain a record of the applicability determination for each engine in FGEXISTINGRICE relative to the requirements of 40 CFR Part 63, Subparts A and ZZZZ. **(40 CFR Part 63, Subpart A, Section 63.10(b)(3))**

See Appendix 3-C

VII. REPORTING

1. Prompt reporting of deviations pursuant to General Conditions 21 and 22 of Part A. **(R 336.1213(3)(c)(ii))**

2. Semiannual reporting of monitoring and deviations pursuant to General Condition 23 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for reporting period July 1 to December 31 and September 15 for reporting period January 1 to June 30. **(R 336.1213(3)(c)(i))**

3. Annual certification of compliance pursuant to General Conditions 19 and 20 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for the previous calendar year. **(R 336.1213(4)(c))**

4. The permittee shall submit to the AQD District Supervisor, a semiannual compliance report, as specified in 40 CFR 63.6650, which contains all deviations during the reporting period from any applicable emission limitation or operating limitation. If there are no deviations from any applicable emission limitations or operating limitations, the report shall contain a statement that there were no deviations during the reporting period. The first report shall cover the period beginning on the applicable compliance date specified in 40 CFR 63.6595 and ending on June 30 (postmarked or delivered by July 31) or December 31 (postmarked or delivered by January 31), whichever date is the first date following the end of the first calendar half after the applicable compliance date. Each subsequent report must cover the semiannual period from January 1 through June 30, or from July 1 through December 31. The subsequent reports must be postmarked or delivered by July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period, except as allowed in 40 CFR 63.6650(b)(5). The compliance report must also contain the following information, as specified in 40 CFR 63.6650(c) and (d):

   a. Company name and address.

   b. Certification of the report by a responsible official.

   c. Date of report and beginning and ending dates of the reporting period.

   d. The number of malfunctions, including a brief description of each event, that occurred during the reporting period and a demonstration that the Malfunction Plan was followed during such events.

   e. The total operating time of the RICE at which the deviation occurred during the reporting period.

   f. The number, duration, and cause of deviations and the corrective action taken.

   A copy of the compliance report shall be kept on file for a period of at least five years (at least two years at the site) and made available to the Department upon request. **(40 CFR 63.6640(b), 40 CFR 63.6650(b),(c),(d), 40 CFR 63.6660)**

5. Each affected source that has obtained a Title V operating permit pursuant to 40 CFR Part 70 or 71 must report all deviations as defined in 40 CFR Part 63, Subpart ZZZZ in the semiannual monitoring report required by 40 CFR 70.6 (a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A). If an affected source submits a Compliance report pursuant to Table 7 of 40 CFR Part 63, Subpart ZZZZ along with, or as part of, the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), and the Compliance report includes all required information concerning deviations from any emission or operating limitation in 40 CFR Part 63, Subpart ZZZZ, submission of the Compliance report shall be deemed to satisfy any obligation to report the same deviations in the semiannual monitoring report. However, submission of a Compliance report shall not otherwise affect any obligation the affected source may have to report deviations from permit requirements to the permit authority. **(40 CFR 63.6650(f))**

   c. For each engine in FGEXISTINGRICE that is an emergency stationary engine with a site rating of more than 100 brake hp that operates or is contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in 40 CFR 63.6640(f)(2)(ii) and (iii) or that operates for the purpose specified in 40 CFR 63.6640(f)(4)(ii), you must submit an annual report according to the requirements below and as specified in 40 CFR 63.6650(h). **(40 CFR 63.6650(h), 40 CFR 63.6660)**

   a. The report must contain the following information:
      i. Company name and address where the engine is located.
      ii. Date of the report and beginning and ending dates of the reporting period.
      iii. Engine site rating and model year.
      iv. Latitude and longitude of the engine in decimal degrees reported to the fifth decimal place.
      v. Hours operated for the purposes specified in 40 CFR 63.6640(f)(2)(ii) and (iii), including the date, start time, and end time for engine operation for the purposes specified in 40 CFR 63.6640(f)(2)(ii) and (iii).
      vi. Number of hours the engine is contractually obligated to be available for the purposes specified in 40 CFR 63.6640(f)(2)(ii) and (iii).

vii. Hours spent for operation for the purpose specified in 40 CFR 63.6640(f)(4)(ii), including the date, start time, and end time for engine operation for the purposes specified in 40 CFR 63.6640(f)(4)(ii). The report must also identify the entity that dispatched the engine and the situation that necessitated the dispatch of the engine.
viii. If there were no deviations from the fuel requirements in 40 CFR 63.6604 that apply to the engine (if any), a statement that there were no deviations from the fuel requirements during the reporting period.
ix. If there were deviations from the fuel requirements in 40 CFR 63.6604 that apply to the engine (if any), information on the number, duration, and cause of deviations, and the corrective action taken.

b. The permittee shall submit annual reports for each calendar year must be submitted no later than March 31 of the following calendar year.

The annual report must be submitted electronically using the subpart specific reporting form in the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through USEPA's Central Data Exchange (CDX) (www.epa.gov/cdx). However, if the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, the written report must be submitted to the Administrator at the appropriate address listed in 40 CFR 63.13.
See Appendix 8

VIII. STACK/VENT RESTRICTION(S)

NA

IX. OTHER REQUIREMENT(S)

1. The permittee shall comply with all applicable provisions of the National Emission Standards for Hazardous Air Pollutants, as specified in 40 CFR Part 63, Subparts A and ZZZZ, for Stationary Reciprocating Internal Combustion Engines by the initial compliance date of May 3, 2013. **(40 CFR 63.6595(a)(1), 40 CFR, Part 63, Subparts A and ZZZZ)**

Footnotes:
[1] This condition is state only enforceable and was established pursuant to Rule 201(1)(b).
[2] This condition is federally enforceable and was established pursuant to Rule 201(1)(a).

FGNEWCIRICE
FLEXIBLE GROUP CONDITIONS

DESCRIPTION

EUWPDIESEL: A Water Pump for EUSDA_U3 emergency flush certified to NSPS IIII Tier 3 requirements. A diesel-powered, stationary internal combustion engine rated at 130 HP (97 kW).

EUTRNCNTRDIESEL: An emergency generator for the Training Center with diesel engine certified to NSPS IIII Tier 3 requirements. A diesel-powered, stationary internal combustion engine rated at 1,193 bHP.

These units are subject to the provisions of 40 CFR Part 60, Subpart IIII and 40 CFR Part 63, Subpart ZZZZ.

Emission Units: EUWPDIESEL, EUTRNCNTRDIESEL

POLLUTION CONTROL EQUIPMENT

NA

I. EMISSION LIMIT(S)

Pollutant	Limit	Time Period/ Operating Scenario	Equipment	Monitoring/ Testing Method	Underlying Applicable Requirements
1. NMHC + NOx	4.0 g/kW-hr[2]	Hourly	EUWPDIESEL	SC V.1 SC VI.2	**40 CFR 60.4205(b), 40 CFR 89.112(a) Table 1**
2. CO	5.0 g/kW-hr[2]	Hourly	EUWPDIESEL	SC V.1 SC VI.2	**40 CFR 60.4202(a)(2), 40 CFR 60.4205(b), 40 CFR 89.112(a) Table 1**
3. PM	0.30 g/kW-hr[2]	Hourly	EUWPDIESEL	SC V.1 SC VI.2	**40 CFR 60.4202(a)(2), 40 CFR 60.4205(b), 40 CFR 89.112(a) Table 1**
4. NMHC + NOx	6.4 g/kW-hr[2]	Hourly	EUTRNCNTRDIESEL	SC V.1 SC VI.2	**40 CFR 60.4205(c)**
5. CO	3.5 g/kW-hr[2]	Hourly	EUTRNCNTRDIESEL	SC V.1 SC VI.2	**40 CFR 60.4205(c)**
6. PM	0.20 g/kW-hr[2]	Hourly	EUTRNCNTRDIESEL	SC V.1 SC VI.2	**40 CFR 60.4205(c)**

II. MATERIAL LIMIT(S)

1. The permittee shall burn only diesel fuel, in EUWPDIESEL and EUTRNCNTRDIESEL with the maximum sulfur content of 15 ppm (0.0015%) by weight and a minimum Cetane index of 40 or a maximum aromatic content of 35 volume percent.[2] **(R 336.1205(1)(a), R 336.1402(1), 40 CFR 60.4207(b), 40 CFR 80.510(b))**

   See Appendix 3-C

III. PROCESS/OPERATIONAL RESTRICTION(S)

1. The permittee shall not operate EUWPDIESEL for more than 100 hours per year on a 12-month rolling time period basis as determined at the end of each calendar month. The 100 hours includes the hours for the purpose

of emergency operation, necessary maintenance checks and readiness testing as described in SC III.2.[2] **(R 336.1205(1)(a), R 336.1225, R 336.1702(a))**

2. The permittee may operate not either EUWPDIESEL or EUTRNCNTRDIESEL for no more than 100 hours per calendar year for the purpose of necessary maintenance checks and readiness testing, provided that the tests are recommended by Federal, State, or local government, the manufacturer, the vendor, or the insurance company associated with the engine. The permittee may petition the Department for approval of additional hours to be used for maintenance checks and readiness testing. A petition is not required if the owner or operator maintains records indicating that Federal, State, or local standards require maintenance and testing of emergency internal combustion engines beyond 100 hours per calendar year. EUWPDIESEL may operate up to 50 hours per calendar year in non-emergency situations, but those 50 hours are counted towards the 100 hours per calendar year provided for maintenance and testing.[2] **(40 CFR 60.4211(f))**

3. If EUWPDIESEL and/or EUTRNCNTRDIESEL is a certified engine, the permittee shall meet the following requirements:
   a. Operate and maintain the certified engine and control device according to the manufacturer's emission-related written instructions;
   b. Change only those emission-related settings that are permitted by the manufacturer; and
   c. Meet the requirements as specified in 40 CFR 89, 94, and/or 1068, as they apply to each engine in FGNEWCIRICE.

   If you do not operate and maintain the certified engine and control device according to the manufacturer's emission-related written instructions, the engine may be considered a non-certified engine.[2] **(40 CFR 60.4211(a))**

4. If EUWPDIESEL and/or EUTRNCNTRDIESEL is a non-certified engine or a certified engine operating in a non-certified manner, the permittee shall keep a maintenance plan and records of conducted maintenance for EUWPDIESEL and must, to the extent practicable, maintain and operate each engine in FGNEWCIRICE in a manner consistent with good air pollution control practice for minimizing emissions.[2] **(40 CFR 60.4211(g)(2))**

IV. DESIGN/EQUIPMENT PARAMETER(S)

1. The permittee shall equip and maintain EUWPDIESEL and EUTRNCNTRDIESEL with a non-resettable hours meter to track the operating hours.[2] **(R 336.1205(1)(a), R 336.1225, 40 CFR 60.4209)**

2. The nameplate capacity of EUWPDIESEL shall not exceed 130 hp, as certified by the equipment manufacturer.[2] **(R 336.1205(1)(a), R 336.1225, 40 CFR 60.4202, 40 CFR 89.112(a))**

3. The nameplate capacity of EUTRNCNTRDIESEL shall not exceed the capacity restrictions (560<kW<=2237) as certified by the equipment manufacturer. **(40 CFR 60.4202)**

V. TESTING/SAMPLING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. Unless EUWPDIESEL and/or EUTRNCNTRDIESEL has been certified by the manufacturer as required by 40 CFR Part 60, Subpart IIII and the permittee maintains the engine as required by 40 CFR 60.4211, the permittee shall conduct an initial performance test to demonstrate compliance with the emission limits in SC I.1 – I.3 for each diesel engine, within one year after startup, or within 1 year after either diesel engine is no longer configured, operated, and maintained in accordance with the manufacturer's emission-related written instructions, or within 1 year after the permittee changes emission-related settings in a way that is not permitted by the manufacturer, to demonstrate compliance with the emission limits in 40 CFR 60.4205(b). If a performance test is required, the performance test shall be conducted according to 40 CFR 60.4212. No less than 30 days prior to testing, a complete test plan shall be submitted to the AQD. The final plan must be approved by the AQD prior to testing. After conducting the initial performance test, the permittee shall conduct subsequent performance testing, for non-certified engines, every 8,760 hours or 3 years, whichever comes first. No less than 30 days prior to testing, the permittee shall submit a complete test plan to the AQD Technical Programs Unit and District Office. The permittee shall notify the AQD Technical Programs Unit Supervisor and the District Supervisor not less than 7 days of the time and place before performance tests are conducted. Verification of emission rates

includes the submittal of a complete report of the test results to the AQD within 60 days following the last date of the test.[2] **(R 336.2001, R 336.2003, R 336.2004, 40 CFR 60.4211(g)(2), 40 CFR 60.4212)**

2. Upon request of the AQD District Supervisor, the permittee shall verify NOx, CO, PM10, and PM2.5 emission rates from EUWPDIESEL or EUTRNCNTRDIESEL by testing at owner's expense, in accordance with the Department requirements. Testing shall be performed using an approved USEPA Method listed in:

Pollutant	Test Method Reference
PM10/PM2.5	40 CFR Part 51, Appendix M
NOx	40 CFR Part 60, Appendix A
CO	40 CFR Part 60, Appendix A

An alternate method, or a modification to the approved USEPA Method, may be specified in an AQD-approved Test Protocol. No less than 30 days prior to testing, the permittee shall submit a complete test plan to the AQD Technical Programs Unit and District Office. The AQD must approve the final plan prior to testing, including any modifications to the method in the test protocol that are proposed after initial submittal. The permittee shall notify the AQD Technical Programs Unit Supervisor and the District Supervisor not less than 7 days of the time and place before performance tests are conducted. The permittee must submit a complete report of the test results to the AQD Technical Programs Unit and District Office within 60 days following the last date of the test.[2] **(R 336.1205, R 336.1225, R 336.2001, R 336.2003, R 336.2004)**

See Appendix 5

VI. MONITORING/RECORDKEEPING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. The permittee shall complete all required calculations in a format acceptable to the AQD District Supervisor by the 30th day of the calendar month, for the previous calendar month, unless otherwise specified in any monitoring/recordkeeping special condition.[2] **(R 336.1205(1)(a))**

2. The permittee shall keep, in a satisfactory manner, records of testing required in SC V.1 or manufacturer certification documentation indicating that EUWPDIESEL and EUTRNCNTRDIESEL meets the applicable requirements contained in the federal Standards of Performance for New Stationary Sources 40 CFR Part 60, Subpart IIII. If EUWPDIESEL or EUTRNCNTRDIESEL becomes uncertified then the permittee must also keep records of a maintenance plan and maintenance activities. The permittee shall keep all records on file and make them available to the Department upon request.[2] **(40 CFR 60.4211(g)(2))**

3. The permittee shall monitor and record the total hours of operation and the hours of operation during non-emergencies for EUWPDIESEL and EUTRNCNTRDIESEL, on a monthly and 12-month rolling time period basis, in a manner acceptable to the AQD District Supervisor. The permittee shall document how many hours are spent for emergency operation of EUWPDIESEL and EUTRNCNTRDIESEL, including what classified the operation as emergency and how many hours are spent maintenance or readiness testing and for non-emergency operation.[2] **(R 336.1205(1)(a), 40 CFR 60.4211, 40 CFR 60.4214(b))**

4. The permittee shall keep, in a satisfactory manner, fuel supplier certification records or fuel sample test data, for each delivery of diesel fuel oil used in EUWPDIESEL and EUTRNCNTRDIESEL, demonstrating that the fuel meets the requirement of 40 CFR 80.510(b). The certification or test data shall include the name of the oil supplier or laboratory, the sulfur content, and cetane index or aromatic content of the fuel oil.[2] **(R 336.1205(1)(a), R 336.1402(1), 40 CFR 80.510(b))**

See Appendices 3, 4, and 7

VII. REPORTING

1. Prompt reporting of deviations pursuant to General Conditions 21 and 22 of Part A. **(R 336.1213(3)(c)(ii))**

2. Semiannual reporting of monitoring and deviations pursuant to General Condition 23 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for reporting period July 1 to December 31 and September 15 for reporting period January 1 to June 30. **(R 336.1213(3)(c)(i))**

3. Annual certification of compliance pursuant to General Conditions 19 and 20 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for the previous calendar year. **(R 336.1213(4)(c))**

4. The permittee shall submit any performance test reports to the AQD Technical Programs Unit and District Office, in a format approved by the AQD. **(R 336.1213(3)(c), R 336.2001(5))**

See Appendix 8

VIII. STACK/VENT RESTRICTION(S)

The exhaust gases from the stacks listed in the table below shall be discharged unobstructed vertically upwards to the ambient air unless otherwise noted:

Stack & Vent ID	Maximum Exhaust Dimensions (inches)	Minimum Height Above Ground (feet)	Underlying Applicable Requirements
1. SVWPDIESEL	14[2]	16[2]	**40 CFR 52.21(c) & (d)**

IX. OTHER REQUIREMENT(S)

1. The permittee shall comply with the provisions of the federal Standards of Performance for New Stationary Sources as specified in 40 CFR Part 60, Subparts A and IIII, as they apply to EUWPDIESEL and EUTRNCNTRDIESEL.[2] **(40 CFR Part 60, Subparts A & IIII, 40 CFR 63.6590)**

2. The permittee shall comply with the provisions of the National Emission Standards for Hazardous Air Pollutants, as specified in 40 CFR Part 63, Subparts A and ZZZZ, as they apply to EUWPDIESEL and EUTRNCNTRDIESEL.[2] **(40 CFR Part 63, Subparts A and ZZZZ, 40 CFR 63.6595)**

Footnotes:
[1] This condition is state only enforceable and was established pursuant to Rule 201(1)(b).
[2] This condition is federally enforceable and was established pursuant to Rule 201(1)(a).

FGAUXBLRS3
FLEXIBLE GROUP CONDITIONS

DESCRIPTION

Two (2) distillate oil fired boilers rated at 9.8 MMBTU heat input, providing heat to Plant 3. These units are subject to the provisions of 40 CFR Part 63, Subpart DDDDD.

Emission Units: EUAUXBLR3B, EUAUXBLR3C (Both are 9.8 MMBTU/hr, Diesel fuel)

POLLUTION CONTROL EQUIPMENT

NA

I. EMISSION LIMIT(S)

NA

II. MATERIAL LIMIT(S)

Material	Limit	Time Period/ Operating Scenario	Equipment	Monitoring/ Testing Method	Underlying Applicable Requirements
1. Fuel Oil – sulfur content	0.4% by weight at 18,000 BTU/lb	Instantaneous; at all times	EUAUXBLR3B EUAUXBLR3C	SC VI.1	**R 336.1282 (b)(ii)**

III. PROCESS/OPERATIONAL RESTRICTION(S)

1. The permittee must meet the tune-up and energy assessment work practice standards for each applicable boiler or process heater at the source. **(40 CFR 63.7500(a)(1), 40 CFR Part 63, Subpart DDDDD, Table 3, Nos. 1-4)**

2. The permittee must operate and maintain affected sources in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to the AQD that may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source. **(40 CFR 63.7500(a)(3))**

3. The permittee may obtain approval from the USEPA Administrator to use an alternative to the tune-up and energy assessment work practice standards. **(40 CFR 63.7500(b))**

4. The permittee must conduct a biennial performance tune-up according to 40 CFR 63.7540(a)(11) as stated in SC III.5, respectively. Each biennial tune-up specified in 40 CFR 63.7540(a)(11) must be conducted no more than 25 months after the previous tune-up. **(40 CFR 63.7515(d))**

5. Boilers or process heaters with a heat input capacity of less than 10 million BTU per hour must conduct a biennial tune-up of the boiler or process heater. **(40 CFR 63.7540(a)(11), 40 CFR 63.7500(e))**

6. The permittee shall conduct the tune-up within 30 days of startup, if the unit is not operating on the required date for a tune-up. **(40 CFR 63.7540(a)(12))**

7. The permittee must demonstrate continuous compliance with the tune-up requirement by completing the following: **(40 CFR 63.7540(a)(10))**

a. Inspect the burner, and clean or replace any components of the burner as necessary (the permittee may delay the burner inspection until the next scheduled unit shutdown). At units where entry into a piece of process equipment or into a storage vessel is required to complete the tune-up inspections, inspections are required only during planned entries into the storage vessel or process equipment. **(40 CFR 63.7540(a)(10)(i))**

b. Inspect the flame pattern, as applicable, and adjust the burner as necessary to optimize the flame pattern. The adjustment should be consistent with the manufacturer's specifications, if available. **(40 CFR 63.7540(a)(10)(ii))**

c. Inspect the system controlling the air-to-fuel ratio, as applicable, and ensure that it is correctly calibrated and functioning properly (the permittee may delay the inspection until the next scheduled unit shutdown). Units that produce electricity for sale may delay the inspection until the first outage, not to exceed 36 months from the previous inspection. **(40 CFR 63.7540(a)(10)(iii))**

d. Optimize total emissions of CO. This optimization should be consistent with the manufacturer's specifications, if available, and with any NOx requirement to which the unit is subject. **(40 CFR 63.7540(a)(10)(iv))**

e. Measure the concentrations in the effluent stream of CO in parts per million, by volume, and oxygen in volume percent, before and after the adjustments are made (measurements may be either on a dry or wet basis, as long as it is the same basis before and after the adjustments are made). Measurements may be taken using a portable CO analyzer. **(40 CFR 63.7540(a)(10)(v))**

f. Maintain on-site and submit, if requested by the AQD, the most recent periodic report containing the information as listed below. **(40 CFR 63.7540(a)(10)(vi))**

   i. The concentrations of CO in the effluent stream in parts per million by volume, and oxygen in volume percent, measured at high fire or typical operating load, before and after the tune-up of the boiler or process heater. **(40 CFR 63.7540(a)(10)(vi)(A))**

   ii. A description of any corrective actions taken as a part of the tune-up. **(40 CFR 63.7540(a)(10)(vi)(B))**

   iii. The type and amount of fuel used over the 12 months prior to the tune-up, but only if the unit was physically and legally capable of using more than one type of fuel during that period. Units sharing a fuel meter may estimate the fuel used by each unit. **(40 CFR 63.7540(a)(10)(vi)(C))**

8. The permittee must complete the Initial tune ups on all affected units except as provided in 40 CFR 63.7510(j) and 40 CFR 63.7540(a)(13). **(40 CFR 63.7510(e))**

9. For affected sources (as defined in 40 CFR 63.7490) that have not operated since the previous compliance demonstration and more than one year has passed since the previous compliance demonstration, the permittee must complete a subsequent tune-up within 30 days of startup by following the procedures described in SC III.7.a through SC III.7.f. **(40 CFR 63.7515(9))**

IV. DESIGN/EQUIPMENT PARAMETER(S)

NA

V. TESTING/SAMPLING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

NA

VI. MONITORING/RECORDKEEPING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. The permittee shall maintain sufficient records to demonstrate that the sulfur content for each shipment of fuel oil received is less than 0.4% by weight. **(R 336.1213(3))**

2. The permittee must keep a copy of each notification and report submitted to comply with 40 CFR Part 63, Subpart DDDDD, including all documentation supporting any Initial Notification or Notification of Compliance Status or semiannual compliance report that the permittee submitted, according to the requirements in 40 CFR 63.10(b)(2)(xiv). **(40 CFR 63.7555(a)(1))**

3. The permittee must keep each record on site, or they must be accessible from on-site (for example, through a computer network), for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record. The permittee can keep the records off site for the remaining 3 years. **(40 CFR 63.7560(a), (b), and (c))**

See Appendix 3-C (Fuel Oil Sulfur Monitoring)

VII. REPORTING

1. Prompt reporting of deviations pursuant to General Conditions 21 and 22 of Part A. **(R 336.1213(3)(c)(ii))**

2. Semiannual reporting of monitoring and deviations pursuant to General Condition 23 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for reporting period July 1 to December 31 and September 15 for reporting period January 1 to June 30. **(R 336.1213(3)(c)(i))**

3. Annual certification of compliance pursuant to General Conditions 19 and 20 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for the previous calendar year. **(R 336.1213(4)(c))**

4. The permittee must submit boiler tune-up compliance reports. Compliance reports must be postmarked or submitted by March 15 of the year following the tune-up and must cover the applicable 1, 2, or 5-year period starting from January 1 of the year following the previous tune-up to December 31 (of the latest tune-up year). Compliance reports must be submitted using the Compliance and Emissions Data Reporting Interface (CEDRI) which is accessed through the USEPA's Central Data Exchange (CDX) (www.epa.gov/cdx). If the reporting form is not available in CEDRI at the time the compliance report is due, a hardcopy of the compliance report shall be submitted to the state and USEPA Region 5. At the discretion of the Administrator, the permittee must submit these reports in the format specified by the Administrator. **(40 CFR 63.7550(b), 40 CFR 63.10(a)(5), 40 CFR 63.7550(h)(3))**

5. Unless the USEPA Administrator has approved a different schedule for submission of reports under 40 CFR 63.10(a), the permittee must submit each report, according to paragraph (h) of 40 CFR 63.7550, stated in SC VII.5, by the date in Table 9 of 40 CFR Part 63, Subpart DDDDD and according to the requirements in paragraphs (b)(1) through (4) of 40 CFR 63.7550, as listed below. For units that are subject only to a requirement to conduct a 5-year tune-up according to 40 CFR 63.7540(a)(12), stated in SC IX.5.b, and not subject to emission limits or operating limits, the permittee may submit only a 5-year compliance report, as specified in paragraphs (b)(1) through (4) of 40 CFR 63.7550, as listed below, instead of a semi-annual compliance report. **(40 CFR 63.7550(a) & (b))**
   a. Each semi-annual compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31. 5-year compliance reports must cover the 5-year period from January 1 to December 31. **(40 CFR 63.7550(b)(3))**
   b. Each semi-annual compliance report must be postmarked or submitted no later than September 15 or March 15, whichever date is the first date following the end of the semiannual reporting period. 5-year compliance reports must be postmarked or submitted no later than March 15. **(40 CFR 63.10(a)(5), 40 CFR 63.7550(b)(4), 40 CFR 63.7550(b)(5))**

6. The permittee must include the following information in the compliance report. **(40 CFR 63.7550(a) & (c))**
   a. If the facility is subject to the requirements of a tune up the permittee must submit a compliance report with the information in paragraphs (c)(5)(i) through (iii), (xiv), and (xvii) of 40 CFR 63.7550. **(40 CFR 63.7550(c)(1))**
   b. 40 CFR 63.7550(c)(5) is as follows:
      i. Company and Facility name and address. **(40 CFR 63.7550(c)(5)(i))**
      ii. Process unit information, emissions limitations, and operating parameter limitations. **(40 CFR 63.7550(c)(5)(ii))**
      iii. Date of report and beginning and ending dates of the reporting period. **(40 CFR 63.7550(c)(5)(iii))**
      iv. Include the date of the most recent tune-up for each unit subject to only the requirement to conduct a 5-year tune-up according to 40 CFR 63.7540(a)(12), stated in SC IX.5.b. Include the date of the most recent burner inspection if it was not done on a 5-year period and was delayed until the next scheduled or unscheduled unit shutdown. **(40 CFR 63.7550(c)(5)(xiv))**
      v. Statement by a responsible official with that official's name, title, and signature, certifying the truth, accuracy, and completeness of the content of the report. **(40 CFR 63.7550(c)(5)(xvii))**

7. The permittee must submit the reports according to the procedures specified in paragraph (h)(3) of 40 CFR 63.7550, as listed below. **(40 CFR 63.7550(h))**
   a. The permittee must submit all reports required by Table 9 of 40 CFR Part 63, Subpart DDDDD electronically to the USEPA via the Compliance and Emissions Data Reporting Interface (CEDRI). (CEDRI can be accessed through the USEPA's CDX.) The permittee must use the appropriate electronic report in CEDRI for 40 CFR Part 63, Subpart DDDDD. Instead of using the electronic report in CEDRI for 40 CFR Part 63, Subpart DDDDD, the permittee may submit an alternate electronic file consistent with the XML schema listed on the CEDRI Web site (*http://www.epa.gov/ttn/chief/cedri/index.html*), once the XML schema is available. If the reporting form specific to 40 CFR Part 63, Subpart DDDDD is not available in CEDRI at the time that the report is due, the permittee must submit the report to the Administrator at the appropriate address listed in 40 CFR 63.13. The permittee must begin submitting reports via CEDRI no later than 90 days after the form becomes available in CEDRI. **(40 CFR 63.7550(h)(3))**

8. The permittee must report each instance in which the permittee did not meet each applicable operating limit in Tables 3 and 4 to 40 CFR Part 63, Subpart DDDDD. These instances are deviations from the operating limits, respectively, in 40 CFR Part 63, Subpart DDDDD. These deviations must be reported according to the requirements in Section 63.7550. **(40 CFR 63.7540(b))**

See Appendix 8

VIII. STACK/VENT RESTRICTION(S)

NA

IX. OTHER REQUIREMENT(S)

1. The permittee shall comply with the applicable requirements of 40 CFR Part 63, Subpart DDDDD - National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters. **(40 CFR Part 63, Subparts A and DDDDD)**

2. The permittee must be in compliance with the work practice standards (tune ups, energy assessment) in 40 CFR Part 63, Subpart DDDDD. **(40 CFR 63.7505(a))**

3. The permittee shall comply with the General Provisions in 40 CFR 63.1 through 40 CFR 63.15 apply to this source as indicated in Table 10 of 40 CFR Part 63, Subpart DDDDD. **(40 CFR 63.7565, Table 10)**

Footnotes:
[1] This condition is state only enforceable and was established pursuant to Rule 201(1)(b).
[2] This condition is federally enforceable and was established pursuant to Rule 201(1)(a).

FGPARTSCLEANERS
FLEXIBLE GROUP CONDITIONS

DESCRIPTION

Any cold cleaner that is grandfathered or exempt from Rule 201 pursuant to Rule 278, 278a and Rule 281(2)(h) or Rule 285(2)(r)(iv). Existing cold cleaners were placed into operation prior to July 1, 1979. New cold cleaners were placed into operation on or after July 1, 1979.

Emission Unit: EUPARTSCLEANERS

POLLUTION CONTROL EQUIPMENT

NA

I. EMISSION LIMIT(S)

NA

II. MATERIAL LIMIT(S)

1. The permittee shall not use cleaning solvents containing more than five % by weight of the following halogenated compounds: methylene chloride, perchloroethylene, trichloroethylene, 1,1,1-trichloroethane, carbon tetrachloride, chloroform, or any combination thereof. **(R 336.1213(2))**

III. PROCESS/OPERATIONAL RESTRICTION(S)

1. Cleaned parts shall be drained for no less than 15 seconds or until dripping ceases. **(R 336.1611(2)(b), R 336.1707(3)(b))**

2. The permittee shall perform routine maintenance on each cold cleaner as recommended by the manufacturer. **(R 336.1213(3))**

IV. DESIGN/EQUIPMENT PARAMETER(S)

1. The cold cleaner must meet one of the following design requirements:

   a. The air/vapor interface of the cold cleaner is no more than ten square feet. **(R 336.1281(2)(h))**

   b. The cold cleaner is used for cleaning metal parts and the emissions are released to the general in-plant environment. **(R 336.1285((2)(r)(iv))**

2. The cold cleaner shall be equipped with a device for draining cleaned parts. **(R 336.1611(2)(b), R 336.1707(3)(b))**

3. All new and existing cold cleaners shall be equipped with a cover and the cover shall be closed whenever parts are not being handled in the cold cleaner. **(R 336.1611(2)(a), R 336.1707(3)(a))**

4. The cover of a new cold cleaner shall be mechanically assisted if the Reid vapor pressure of the solvent is more than 0.3 psia or if the solvent is agitated or heated. **(R 336.1707(3)(a))**

5. If the Reid vapor pressure of any solvent used in a new cold cleaner is greater than 0.6 psia; or, if any solvent used in a new cold cleaner is heated above 120 degrees Fahrenheit, then the cold cleaner must comply with at least one of the following provisions:

a. The cold cleaner must be designed such that the ratio of the freeboard height to the width of the cleaner is equal to or greater than 0.7. **(R 336.1707(2)(a))**

b. The solvent bath must be covered with water if the solvent is insoluble and has a specific gravity of more than 1.0. **(R 336.1707(2)(b))**

c. The cold cleaner must be controlled by a carbon adsorption system, condensation system, or other method of equivalent control approved by the AQD. **(R 336.1707(2)(c))**

V. TESTING/SAMPLING

NA

VI. MONITORING/RECORDKEEPING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. For each new cold cleaner in which the solvent is heated, the solvent temperature shall be monitored and recorded at least once each calendar week during routine operating conditions. **(R 336.1213(3))**

2. The permittee shall maintain the following information on file for each cold cleaner: **(R 336.1213(3))**

   a. A serial number, model number, or other unique identifier for each cold cleaner.

   b. The date the unit was installed, manufactured or that it commenced operation.

   c. The air/vapor interface area for any unit claimed to be exempt under Rule 281(2)(h).

   d. The applicable Rule 201 exemption.

   e. The Reid vapor pressure of each solvent used.

   f. If applicable, the option chosen to comply with Rule 707(2).

3. The permittee shall maintain written operating procedures for each cold cleaner. These written procedures shall be posted in an accessible, conspicuous location near each cold cleaner. **(R 336.1611(3), R 336.1707(4))**

4. As noted in Rule 611(2)(c) and Rule 707(3)(c), if applicable, an initial demonstration that the waste solvent is a safety hazard shall be made prior to storage in non-closed containers. If the waste solvent is a safety hazard and is stored in non-closed containers, verification that the waste solvent is disposed of so that not more than 20%, by weight, is allowed to evaporate into the atmosphere shall be made on a monthly basis. **(R 336.1213(3), R 336.1611(2)(c), R 336.1707(3)(c))**

VII. REPORTING

1. Prompt reporting of deviations pursuant to General Conditions 21 and 22 of Part A. **(R 336.1213(3)(c)(ii))**

2. Semiannual reporting of monitoring and deviations pursuant to General Condition 23 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for reporting period July 1 to December 31 and September 15 for reporting period January 1 to June 30. **(R 336.1213(3)(c)(i))**

3. Annual certification of compliance pursuant to General Conditions 19 and 20 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for the previous calendar year. **(R 336.1213(4)(c))**

See Appendix 8

VIII. STACK/VENT RESTRICTION(S)

NA

IX. OTHER REQUIREMENT(S)

NA

E. NON-APPLICABLE REQUIREMENTS

At the time of the ROP issuance, the AQD has determined that no non-applicable requirements have been identified for incorporation into the permit shield provision set forth in the General Conditions in Part A pursuant to Rule 213(6)(a)(ii).

APPENDICES

Appendix 1-A. Acronyms and Abbreviations

Common Acronyms		Pollutant / Measurement Abbreviations	
AQD	Air Quality Division	acfm	Actual cubic feet per minute
BACT	Best Available Control Technology	BTU	British Thermal Unit
CAA	Clean Air Act	°C	Degrees Celsius
CAM	Compliance Assurance Monitoring	CO	Carbon Monoxide
CEM	Continuous Emission Monitoring	CO_2e	Carbon Dioxide Equivalent
CEMS	Continuous Emission Monitoring System	dscf	Dry standard cubic foot
CFR	Code of Federal Regulations	dscm	Dry standard cubic meter
COM	Continuous Opacity Monitoring	°F	Degrees Fahrenheit
Department/ department	Michigan Department of Environment, Great Lakes, and Energy	gr	Grains
		HAP	Hazardous Air Pollutant
EGLE	Michigan Department of Environment, Great Lakes, and Energy	Hg	Mercury
		hr	Hour
EU	Emission Unit	HP	Horsepower
FG	Flexible Group	H_2S	Hydrogen Sulfide
GACS	Gallons of Applied Coating Solids	kW	Kilowatt
GC	General Condition	lb	Pound
GHGs	Greenhouse Gases	m	Meter
HVLP	High Volume Low Pressure*	mg	Milligram
ID	Identification	mm	Millimeter
IRSL	Initial Risk Screening Level	MM	Million
ITSL	Initial Threshold Screening Level	MW	Megawatts
LAER	Lowest Achievable Emission Rate	NMOC	Non-methane Organic Compounds
MACT	Maximum Achievable Control Technology	NO_x	Oxides of Nitrogen
MAERS	Michigan Air Emissions Reporting System	ng	Nanogram
MAP	Malfunction Abatement Plan	PM	Particulate Matter
MSDS	Material Safety Data Sheet	PM10	Particulate Matter equal to or less than 10 microns in diameter
NA	Not Applicable		
NAAQS	National Ambient Air Quality Standards	PM2.5	Particulate Matter equal to or less than 2.5 microns in diameter
NESHAP	National Emission Standard for Hazardous Air Pollutants	pph	Pounds per hour
		ppm	Parts per million
NSPS	New Source Performance Standards	ppmv	Parts per million by volume
NSR	New Source Review	ppmw	Parts per million by weight
PS	Performance Specification	%	Percent
PSD	Prevention of Significant Deterioration	psia	Pounds per square inch absolute
PTE	Permanent Total Enclosure	psig	Pounds per square inch gauge
PTI	Permit to Install	scf	Standard cubic feet
RACT	Reasonable Available Control Technology	sec	Seconds
ROP	Renewable Operating Permit	SO_2	Sulfur Dioxide
SC	Special Condition	TAC	Toxic Air Contaminant
SCR	Selective Catalytic Reduction	Temp	Temperature
SNCR	Selective Non-Catalytic Reduction	THC	Total Hydrocarbons
SRN	State Registration Number	tpy	Tons per year
TEQ	Toxicity Equivalence Quotient	µg	Microgram
USEPA/EPA	United States Environmental Protection Agency	µm	Micrometer or Micron
		VOC	Volatile Organic Compounds
VE	Visible Emissions	yr	Year

*For HVLP applicators, the pressure measured at the gun air cap shall not exceed 10 psig.

Appendix 1-B. Definitions Related to the Consent Agreement.

The following definitions apply to permit conditions originally established in the consent decree settling, "U.S. v Consumers Energy Company, Civil Action No. 14-13580, E.D. Mich., 2014." This Appendix is also federally enforceable pursuant to Section 324.5503(b) of the Natural Resources and Environmental Protection Act, 1994 Act 451, as amended, Rule 201(1)(a), and Rule 214a, and will remain in effect after termination of the consent decree. **(Act 451, Section 324.5503(b))**

- For the purposes of the Consent Decree, every term expressly defined by this Appendix shall have the meaning given that term herein. Every other term used in the Consent Decree that is also a term used under the Act or in a federal regulation implementing the Act shall mean in the Consent Decree what such term means under the Act or those regulations. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 4)**
- A "30-Day Rolling Average Emission Rate" for a Unit shall be expressed in lb/MMBTU and calculated in accordance with the following procedure: first, sum the total pounds of NO_x or SO_2 emitted from the Unit during the current Unit Operating Day and the previous 29 Unit Operating Days; second, sum the total heat input to the Unit in MMBTU during the current Unit Operating Day and the previous 29 Unit Operating Days; and third, divide the total number of pounds of NO_x or SO_2 emitted during the 30 Unit Operating Days by the total heat input during the 30 Unit Operating Days. A new 30-Day Rolling Average Emission Rate shall be calculated for each new Unit Operating Day. Each 30-Day Rolling Average Emission Rate shall include all emissions that occur during all periods within any Unit Operating Day, including emissions from startup, shutdown, and malfunction. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 5)**
- A "90-Day Rolling Average Emission Rate" for a Unit shall be expressed in lb/MMBTU and calculated in accordance with the following procedure: first, sum the total pounds of NO_x or SO_2 emitted from the Unit during the current Unit Operating Day and the previous 89 Unit Operating Days; second, sum the total heat input to the Unit in MMBTU during the current Unit Operating Day and the previous 89 Unit Operating Days; and third, divide the total number of pounds of NO_x or SO_2 emitted during the 90 Unit Operating Days by the total heat input during the 90 Unit Operating Days. A new 90-Day Rolling Average Emission Rate shall be calculated for each new Unit Operating Day. Each 90-Day Rolling Average Emission Rate shall include all emissions that occur during all periods within any Unit Operating Day, including emissions from startup, shutdown, and malfunction. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 6)**
- A "365-Day Rolling Average Emission Rate" for a Unit shall be expressed in lb/MMBTU and calculated in accordance with the following procedure: first, sum the pounds of the pollutant in question emitted from the Unit during the most recent Unit Operating Day and the previous 364 Unit Operating Days; second, sum the total heat input to the Unit in MMBTU during the most recent Unit Operating Day and the previous 364 Unit Operating Days; and third, divide the total number of pounds of the pollutant emitted during the 365 Unit Operating Days by the total heat input during the 365 Unit Operating Days. A new 365-Day Rolling Average Emission Rate shall be calculated for each new Unit Operating Day. Each 365-Day Rolling Average Emission Rate shall include all emissions that occur during all periods of operation, including startup, shutdown, and malfunction. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 7)**
- "Baghouse" means a full stream (fabric filter or membrane) particulate emissions control device. Full stream is defined as capturing the entire stream of exhaust gas with no concurrent by-pass. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 8)**
- "Campbell" means Consumers' J.H. Campbell Generating Plant consisting of three electric utility steam-generating units designated as Unit l (260 MW), Unit 2 (360 MW), and Unit 3 (835 MW) and related equipment, located in West Olive, Ottawa County, Michigan. Campbell Unit 3 is co-owned by Consumers (approximately 93%) along with Wolverine Power Supply Cooperative and the Michigan Public Power Association. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 10)**
- "CEMS" or "Continuous Emission Monitoring System," means, for obligations involving the monitoring of NO_x and SO_2 emissions under the Consent Decree, the devices defined in 40 CFR 72.2 and installed and

maintained as required by 40 CFR Part 75. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 12)**

- "Clean Air Act" or "CAA" or "Act" means the federal Clean Air Act, 42 U.S.C. §§ 7401-7671q, and it's implementing regulations. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 13)**
- "Cobb" means, for purposes of the Consent Decree, Consumers' B.C. Cobb Generating Plant consisting of two electric utility steam-generating units designated as Unit 4 (160 MW) and Unit 5 (160 MW) and related equipment, located in Muskegon, Muskegon County, Michigan. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 14)**
- "Consent Decree" means Consent Decree ("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014") and its Appendices. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 15)**
- "Consumers" means Consumers Energy Company. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 16)**
- "Consumers System" means the Campbell, Cobb, Karn, Weadock, and Whiting facilities as defined herein. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 17)**
- "Continuously Operate" or "Continuous Operation" means that when a pollution control technology or combustion control is required to be used at a Unit pursuant to the Consent Decree (including, but not limited to, SCR, FGD, DSI, ESP, Baghouse, or Low NOx Combustion System), it shall be operated at all times that the Unit it serves is in operation, except the SCRs on Campbell Units 2 and 3 need not be operated during scheduled maintenance on the applicable Unit's Urea Based Ammonia System and consistent with the technological limitations, manufacturers' specifications, good engineering and maintenance practices (including Campbell Unit 2 and Unit 3 scheduled Urea Based Ammonia System outages), and good air pollution control practices for minimizing emissions (as defined in 40 CFR 60.11(d)), as applicable, for such equipment and the Unit. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 18)**
- "Date of Entry" means the date the Consent Decree was signed by the United States District Court Judge (i.e. November 4, 2014). **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 19)**
- "Day" means calendar day unless otherwise specified in the Consent Decree. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 21)**
- "Dry Sorbent Injection" or "DSI" means a process in which a sorbent is pneumatically injected into the ducting downstream of where the coal is combusted and flue gas is produced, and upstream of the PM Control Device. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 22)**
- "Electrostatic Precipitator" or "ESP" means a device for removing particulate matter from combustion gases by imparting an electric charge to the particles and then attracting them to a metal plate or screen of opposite charge before the combustion gases are exhausted to the atmosphere. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 23)**
- "Emission Rate" for a given pollutant means the number of pounds of that pollutant emitted per million British Thermal Units of heat input (lb/MMBTU), calculated in accordance with each applicable 30, 90 or 365-Day Rolling Average Emission Rate definition. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 24)**
- "Flue Gas Desulfurization System" or "FGD" means a pollution control device that employs flue gas desulfurization technology, including an absorber or absorbers utilizing lime or limestone, or a sodium based material, for the reduction of SO_2 emissions. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 27)**
- "Fossil Fuel" means any hydrocarbon fuel, including coal, petroleum coke, petroleum oil, or natural gas. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 29)**
- "Full Stream Operation" is defined as the design configuration of a control device such that it captures the

entire stream of exhaust gas with no concurrent by-pass. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 30)**

- "Karn," for purposes of the Consent Decree, means Consumers' D.E. Karn Generating Plant consisting of two electric utility steam-generating units designated as Unit 1 (255 MW) and Unit 2 (260 MW) and related equipment, located in Essexville, Bay County, Michigan. Karn does not include the oil-fired electricity generating units designated as Karn Units 3 and 4, also located in Essexville, Bay County, Michigan. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 34)**
- "Karn Units 3 and 4" means Consumers' oil-fired Units 3 and 4, in Essexville, Bay County, Michigan. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 35)**
- "KW" means Kilowatt or one thousand watts net. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 36)**
- "lb/MMBTU" means one pound per million British Thermal Units. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 37)**
- "Low NOx Combustion System" means burners and associated combustion air control equipment, including Over Fire Air if specified, which control mixing characteristics of Fossil Fuel and oxygen, thus restraining the formation of NO_x during combustion of fuel in the boiler. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 38)**
- "Malfunction" means a failure to operate in a normal or usual manner by any air pollution control equipment, process equipment, or a process, which is sudden, infrequent, and not reasonably preventable. Failures that are caused in part by poor maintenance or careless operation are not malfunctions. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 39)**
- "Michigan SIP" means the Michigan State Implementation Plan, and any amendments thereto, as approved by USEPA pursuant to Section 110 of the Act, 42 U.S.C. § 7410. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 40)**
- "MW" means a megawatt or one million watts net. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 41)**
- "NO_x" means oxides of nitrogen, measured in accordance with the provisions of the Consent Decree. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 45)**
- "NO_x Allowance" means an authorization to emit a specified amount of NO_x that is allocated or issued under an emissions trading or marketable permit program of any kind established under the Clean Air Act or the Michigan SIP; provided, however, that with respect to any such program that first applies to emissions occurring after December 31, 2011, a "NO_x Allowance" shall include an allowance created and allocated to a Consumers System Unit under such program only for control periods starting on or after November 4, 2018. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 46)**
- "Operating Day" means any calendar day on which a Unit fires Fossil Fuel. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 49)**
- "Over Fire Air" or "OFA" mean an in-furnace staged combustion control to reduce NO_x emissions. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 51)**
- "PM" means total filterable particulate matter, measured in accordance with the provisions of the Consent Decree. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 53)**
- "PM Continuous Emission Monitoring System" or "PM CEMS" means, for obligations involving the monitoring of PM emissions under the Consent Decree, the equipment that samples, analyzes, measures, and provides, by readings taken at frequent intervals, an electronic and/or paper record of PM emissions. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 54)**
- "PM Control Device" means any device, including an ESP or Baghouse, which reduces emissions of PM. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 55)**
- "PM Emission Rate" means the number of pounds of PM emitted per million BTU of heat input (lb/MMBTU). **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 56)**

- "Selective Catalytic Reduction" or "SCR" means an air pollution control device for reducing NO_x emissions in which ammonia ("NH_3") is added to the flue gas and then passed through layers of a catalyst material. The ammonia and NO_x in the flue gas stream react on the surface of the catalyst, forming nitrogen ("N_2") and water vapor. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 61)**
- "SO_2" means sulfur dioxide, measured in accordance with the provisions of the Consent Decree. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 62)**
- "SO_2 Allowance" means an authorization to emit a specified amount of SO_2 that is allocated or issued under an emissions trading or marketable permit program of any kind established under the Clean Air Act or the Michigan SIP; provided, however, that with respect to any such program that first applies to emissions occurring after December 31, 2011, an "SO_2 Allowance" shall include an allowance created and allocated to a Consumers System Unit under such program only for control periods starting on or after November 4, 2018. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 63)**
- "State" means the State of Michigan. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 64)**
- "State Implementation Plan" or "SIP" means regulations and other materials promulgated by a state for purposes of meeting the requirements of the Act that have been approved by USEPA pursuant to Section IIO of the Act, 42 U.S.C. § 74IO. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 65)**
- "Surrender" or "Surrender of Allowances" means, for purposes of SO_2 or NO_x allowances, permanently surrendering allowances from the accounts administered by USEPA and Michigan for all Units in the Consumers System, so that such allowances can never be used thereafter to meet any compliance requirements under the Act, a SIP, or the Consent Decree. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 66)**
- "System-Wide Annual NO_x Tonnage Limitation" means the limitations, as specified in the Consent Decree, on the number of tons of NO_x that may be emitted from Campbell, Cobb, Kam, Weadock, and Whiting, collectively, during the relevant calendar year (i.e., January 1 through December 31), and shall include all emissions of NO_x during all periods of operations, including startup, shutdown, and malfunction. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 67)**
- "System-Wide Annual SO_2 Tonnage Limitation" means the limitations, as specified in the Consent Decree, on the number of tons of SO_2 that may be emitted from Campbell, Cobb, Kam, Weadock, and Whiting, collectively, during the relevant calendar year (i.e., January 1 through December 31), and shall include all emissions of SO_2 during all periods of operations, including startup, shutdown, and malfunction. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 68)**
- "Title V Permit" means the permit required of Consumers' major sources pursuant to Subchapter V of the Act, 42 U.S.C. §§ 7661-7661e. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 69)**
- "Unit" means collectively, the coal pulverizer, stationary equipment that feeds coal to the boiler, the boiler that produces steam for the steam turbine, the steam turbine, the generator, the equipment necessary to operate the generator, steam turbine, and boiler, and all ancillary equipment, including pollution control equipment and systems necessary for production of electricity. An electric steam generating station may comprise one or more Units. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 70)**
- "Urea Based Ammonia System" or "UBAS" means a type of ammonia feed system for SCRs where solid urea pellets are stored in a silo. Upon use,the solid urea is heated to liquid, thermally decomposed to ammonia, and injected into the SCR as the reagent for the NO_x reduction reaction. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 71)**
- "Weadock" means, for purposes of the Consent Decree, Consumers' J.C. Weadock Generating Plant consisting of two electric utility steam-generating Units designated as Unit 7 (155 MW) and Unit 8 (155 MW) and related equipment, located in Essexville, Bay County, Michigan. **("U.S. v Consumers Energy**

Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 72)

- "Whiting" means, for purposes of the Consent Decree, Consumers' Whiting Generation Station consisting of three electric utility steam-generating Units designated as Unit 1 (102 MW), Unit 2 (102 MW), and Unit 3 (124 MW) and related equipment, located in Luna Pier, Monroe County, Michigan. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 73)**

Appendix 2. Schedule of Compliance

The permittee certified in the ROP application that this stationary source is in compliance with all applicable requirements and the permittee shall continue to comply with all terms and conditions of this ROP. A Schedule of Compliance is not required. **(R 336.1213(4)(a), R 336.1119(a)(ii))**

Appendix 3. Monitoring Requirements

Appendix 3-A. Continuous Opacity Monitoring Systems

(This section applies to each boiler.)

The Continuous Opacity Monitoring System (COMS) performance specifications defined in 40 CFR Part 60, Appendix B, are adopted.

Cycling time for opacity: complete a minimum of one cycle of sampling/analysis for each successive 10-second period and one cycle of data recording for each successive 6-minute period. **(R 336.2152)**

Zero and Drift: The COMS must be subject to the manufacturer's zero and span check at least once daily. **(R 336.2153)**

Location: The location of the COMS or the monitoring devices must be such that representative measurement of emissions or process parameters are obtained. **(R 336.2155)**

Alternative Systems: AQD may approve the use of an alternative monitoring system if one is available that meets COMS objectives and if, because of physical limitations or other reasons, COMS cannot be installed or give accurate measurements. **(R 336.2159)**

Monitoring and reporting requirements shall not apply during any period of monitoring system malfunction if it can be demonstrated to the satisfaction of AQD that: the cause of the malfunction could not have been avoided by any reasonable action and necessary repairs are being made as expeditiously as practicable. **(R 336.2190)**

Appendix 3-B. Continuous Emissions Monitoring System (Title IV; Gas Flow, SO2 , CO2, NOx)

(This section applies to each boiler.)

The CEMS performance specifications defined in 40 CFR Part 75, Appendix B, are adopted.

Methods of measurement, frequency of measurement and recordkeeping methods for CEMS required under 40 CFR 75 are outlined in the most recent version of the Acid Rain Program - J. H. Campbell Plant Monitoring Plan, originally dated July 19, 1993.

Data Reporting: the AQD may approve alternative data reporting or reduction procedures if it can be demonstrated that such procedures are at least as accurate as the procedures identified in R 336.2175.

Appendix 3-C. Fuel Oil Sulfur Monitoring

Maintain a complete record of fuel oil specifications and/or a fuel analysis for each delivery, or storage tank, of fuel oil. These records may include purchase records for ASTM specification fuel oil, specifications or analyses provided by the vendor at the time of delivery, analytical results from laboratory testing, or any other records adequate to demonstrate compliance with the percent sulfur limit in fuel oil.

Appendix 3-D. Continuous Emission Monitoring Systems (SO2/CO2)

(This section applies to Units 1 and 2.)

The Continuous Emissions Monitoring Systems (CEMS) performance specifications defined in 40 CFR Part 75, Appendix B, are adopted. The Certified SO_2 and CO_2 monitors will be used to determine sulfur dioxide emissions. The data reduction procedures defined in R 336.2175 will be used to determine SO_2 lbs/MMBTU. On the last day of each calendar month, the CEMS data recording system will generate and record an "operating monthly average" as the average of the previous 31 operating days.

Appendix 3-E. PM CEMS

This Appendix is federally enforceable and was established pursuant to Rule 201(1)(a). This Appendix was originally established in the consent decree settling, "U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" and also pursuant Section 324.5503(b) of the Natural Resources and Environmental Protection Act, 1994 Act 451, as amended, and will remain in effect after termination of the consent decree. Definitions specific to this Appendix may be found in Appendix 1-B: Definitions. **(Act 451, Section 324.5503(b))**

- Consumers shall install, correlate, maintain, and operate a PM CEMS on Campbell Unit 3 as specified below. The PM CEMS shall comprise a continuous particle mass monitor measuring particulate matter concentration, directly or indirectly, on an hourly average basis and a diluent monitor used to convert the concentration to units expressed in lb/MMBTU. The PM CEMS installed must be appropriate for the anticipated stack conditions and capable of measuring PM concentrations on an hourly average basis. Consumers shall maintain, in an electronic database, the hourly average emission values of the PM CEMS in lb/MMBTU. Except for periods of monitor malfunction, maintenance, calibration, or repair, Consumers shall continuously operate the PM CEMS at all times when the Unit it serves is operating. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 159)**
- In developing both the plan for installation and correlation of the PM CEMS and the QA/QC protocol, Consumers shall use the criteria set forth in 40 CFR Part 60, Appendix B, Performance Specification 11, and Appendix F, Procedure 2. Following USEPA's approval of the plan described in Paragraph 160 of the Consent Decree and the QA/QC protocol described in Paragraph 161 of the Consent Decree, Consumers shall thereafter operate the PM CEMS in accordance with the approved plan and QA/QC protocol. Notwithstanding any other provision of the Consent Decree, exceedances of the PM Emission Rate that occur as a result of de-optimizing emission controls and/or spiking the exhaust gas with excess particulate required to achieve the high level PM test runs during the correlation testing shall not be a violation of the requirements of the Consent Decree (or credible evidence thereof); provided, however, that Consumers shall make best efforts to keep the high level PM test runs during such correlation testing below the applicable PM Emission Rate. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 162)**
- Consumers shall, correlate, maintain, and commence Continuous Operation of the PM CEMS approved by EGLE at Campbell Unit 3, conduct performance specification tests on the PM CEMS, and demonstrate compliance with the PM CEMS installation and correlation plans submitted to and approved by EGLE. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 163)**
- Except as approved pursuant to Paragraph 157 of the Consent Decree, stack testing shall be used to determine compliance with the PM Emission Rates established by the Consent Decree. Data from PM

CEMS shall be used, at a minimum, to provide information to operators on PM emissions rate trends on a continuous basis. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 164)**

- The data recorded by the PM CEMS shall be expressed in lb/MMBTU on a rolling average 3-hour basis to identify any PM emission rates in excess of the applicable PM Emission Rate and shall be available in electronic format. **(U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 163)**

Appendix 3-F. Optimization of Baghouses

This Appendix is federally enforceable and was established pursuant to Rule 201(1)(a). This Appendix was originally established in the consent decree settling, "U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" and also pursuant Section 324.5503(b) of the Natural Resources and Environmental Protection Act, 1994 Act 451, as amended, and will remain in effect after termination of the consent decree. Definitions specific to this Appendix may be found in Appendix 1-B: Definitions. **(Act 451, Section 324.5503(b))**

Consumers shall:

a) At a minimum, to the extent practicable: (i) operate each compartment of the Baghouse as designed for Full Stream Operation for each Unit, where applicable (regardless of whether those actions are needed to comply with opacity limits); (ii) maintain and replace bags on each Baghouse as needed to maximize collection efficiency, where applicable; and
b) During the next planned Unit outage (or unplanned outage of sufficient length), optimize the PM controls on that Unit by inspecting for and repairing any failed Baghouse compartment.

The above requirements are found in **"U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 141.**

Appendix 4. Recordkeeping

Specific recordkeeping requirement formats and procedures are detailed in Part A or the appropriate Source-Wide, Emission Unit and/or Flexible Group Special Conditions. Therefore, this appendix is not applicable.

Appendix 5. Testing Procedures

This Appendix is federally enforceable and was established pursuant to Rule 201(1)(a). This Appendix was originally established in the consent decree settling, "U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" and also pursuant Section 324.5503(b) of the Natural Resources and Environmental Protection Act, 1994 Act 451, as amended, and will remain in effect after termination of the consent decree. Definitions specific to this Appendix may be found in Appendix 1-B: Definitions. **(Act 451, Section 324.5503(b))**

Specific testing requirement plans, procedures and averaging times are detailed in the appropriate Requirement Tables. Moreover, the permittee shall use the following approved test plans, procedures and averaging times to measure the pollutant emissions for the applicable requirements referenced in Table EUBOILER3 (see below). Alternative test plans, procedures, or averaging must be approved by the AQD District Supervisor.

Test Methods and Procedures for Boiler #3

In conducting the performance test as required in 40 CFR 60.8, the owner or operator shall use the reference methods, procedures and test methods in 40 CFR Part 60, Appendix A or other methods and procedures specified in Section 60.46(d), except as provided in Section 60.8(b).

1. Particulate Matter: Method 17 at a facility without wet flue gas desulfurization system and Method 5B shall be used after flue gas desulfurization system. Method 5 and MATS method 5 shall also be used.

2. Opacity: Method 9.

3. SO_2: Method 6C shall be in the same sample site selected for particulate sample. The emission rate correction factor, integrated sampling and analysis procedure of Method 3A shall be used to determine the O_2 or CO_2 concentration, and shall be taken simultaneously and in the same point as the SO_2 sample.

2. NO_x: Method 7E shall be in the same sample site selected for particulate sample. The emission rate correction factor, integrated sampling and analysis procedure of Method 3A shall be used to determine the O_2 or CO_2 concentration, and shall be taken simultaneously and in the same point as the NO_x sample.

PM Emissions Testing and Monitoring Requirements

- Annually unless a Unit is Retired or Refueled to Natural Gas, Consumers shall conduct a stack test for PM pursuant to Paragraph 154 of the Consent Decree. The annual performance test requirement imposed on Consumers by this paragraph may be satisfied by stack tests conducted by Consumers as may be required by other conditions in its ROP for any year that such stack tests are required. Consumers may perform testing every other year, rather than every year, provided that two of the most recently completed test results from tests conducted in accordance with the methods and procedures specified above demonstrate that the PM emissions are equal to or less than 0.010 lb/MMBTU. Consumers shall perform testing every year, rather than every other year, beginning in the year immediately following any test result demonstrating that the PM emissions are greater than 0.010 lb/MMBTU.. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 153)**

- To determine compliance with the PM Emission Rate established in Subsections VI.B (Unit-Specific PM Requirements at Campbell Units 1 and 2), Consumers shall use the applicable reference methods and procedures (filterable portion only) specified in its ROP and the Michigan SIP for Campbell Units 1 and 2. Each test shall consist of three separate runs performed under representative operating conditions not including periods of startup, shutdown, or malfunction. The sampling time for each run associated with a Unit controlled by a Baghouse shall be at least 120 minutes and the volume of each run shall be at least 1.70 dry standard cubic meters (60 dry standard cubic feet). Consumers shall calculate the PM Emission Rate from the stack test results in accordance with 40 CFR 60.8(f). The results of each PM stack test shall be submitted to EGLE within 60 Days of completion of each test. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 154)**

- As an alternative to the PM testing required in this Appendix (PM Emissions Testing and Monitoring Requirements; beginning at paragraph 153) of the Consent Decree, following the installation and operation of PM CEMS as required by Appendix 3-E (PM CEMS), Consumers, at its sole discretion, may seek USEPA approval pursuant to Section XIII (Review and Approval of Submittals; beginning at paragraph 193) of the Consent Decree to forego stack testing and instead demonstrate continuous compliance with an applicable filterable PM Emission Rate by using the PM CEMS data on a 3-hour rolling average basis. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 157)**

  Note: JHC EUBOILER3 was approved by USEPA to use the PM CEMS alternative to testing per letter dated January 20, 2020 and mailed on February 3, 2020 this PM CEMS approval letter is available upon request.

Appendix 6. Permits to Install

The following table lists any PTIs issued or ROP revision applications received since the effective date of the previously issued ROP No. MI-ROP-B2835-2013. Those ROP revision applications that are being issued concurrently with this ROP renewal are identified by an asterisk (*). Those revision applications not listed with an asterisk were processed prior to this renewal.

Source-Wide PTI No MI-PTI-B2835-2013 is being reissued as Source-Wide PTI No. MI-PTI-B2835-2020b.

Permit to Install Number	ROP Revision Application Number	Description of Equipment or Change	Corresponding Emission Unit(s) or Flexible Group(s)
142-12	201500412	PTI No. 141-12 incorporated EUCATDIESEL12.	EUCATDIESEL12
18-15	201500412	Incorporated USEPA Consent Decree conditions and to bridge the conditions with PTI No. 39-15. It also incorporated updates to control equipment that had been installed.	EUBYPRODUCT EUACIU123 EUDSI_U12 UESDA_U3
39-15	201500061	Incorporated Conditions of the USEPA Consent Decree that states: "The following must be included in the permit: a schedule for all unit-specific, plant-specific, and system-specific performance, operational, maintenance, and control technology requirements established by this Consent Decree including, but not limited to, any (a) 30-Day, 90-Day and 365-Day Rolling Average Emission Rates, (b) System-Wide Annual NOx and SO2 Tonnage Limitations, (c) the requirements pertaining to the Surrender of NOx and SO2 Allowances, (d) PM Emission Rate and annual stack test requirements, and (e) PM CEMS monitoring requirements."	EUBOILER1 EUBOILER2 EUBOILER3 Appendices 1, 3, 5, 7, and 10
18-15A	201800102*	Ash and byproduct handling system that transports ash and byproduct from the plant to the disposal silos. Unit 3 System: • 2 Transfer tanks each with a built in filter separator • 5 Vacuum Exhausters – exhaust to the Unit 3 PJFF Inlet Unit 1 and 2 System: • 2 Transfer tanks each with a built in filter separator • 3 Vacuum Exhausters – normally discharge to the Unit 1 PJFF inlet except for times when the Unit 1 PJFF is unavailable Common: • 3 Disposal Silos (A, B & C) • Truck loading	EUBYPRODUCT

The following table lists the ROP amendments or modifications issued after the effective date of ROP No. MI-ROP-B2835-2020.

Permit to Install Number	ROP Revision Application Number - Issuance Date	Description of Equipment or Change	Corresponding Emission Unit(s) or Flexible Group(s)
50-20	202000099 / September 3, 2020	Incorporate PTI 50-20 into the ROP, which was to correct emission limits for the water pump EUWPDIESEL. The change was due to an incorrect emission limit cited from 40 CFR Part 60 Subpart IIII in the previous permit but the correct emission limit was	EUWPDIESEL EUTRNCNTRDIESEL FGNEWCIRICE

Permit to Install Number	ROP Revision Application Number - Issuance Date	Description of Equipment or Change	Corresponding Emission Unit(s) or Flexible Group(s)
		used in the permit review. This correction was considered administrative and not subject to New Source Review during permitting. Additionally, the company identified two other errors in their ROP. The errors were related to the other engine in the flexible group, EUTRNCNTRDIESEL, which was not originally permitted through a PTI but was grouped with the fire pump engine EUWPDIESEL in the ROP. These errors were related to what federal subpart was/was not applicable to that engine. It appears that EUTRNCTRDIESEL was accidently included in FGNEWCIRICE Special Condition III. 1 at same time that EUTRNCNTRDIESEL was accidently excluded from FGNEWCIRICE Special Condition III. 2. These emission units were corrected in FGNEWCIRICE. PTI 50-20 was not required to go through the public participation process.	
39-15A	202100070 / July 1, 2021	Incorporate PTI No. 39-15A into the ROP, which was for administrative updates to permitted conditions to reflect the termination of a Consent Decree between the USEPA and Consumers Energy. PTI No. 39-15A previously allowed Boiler #1 and #2 to have individual stacks or meet certain requirements if using a shared stack. The option and associated requirements for having a shared stack are also removed during this minor modification. It should be noted that PTI No. 39-15A had some errors that were corrected during this Modification. During the last ROP Renewal, the Company requested that the conditions common to boilers 1 and 2 housed in FGBOILER12 be separated and put into their respective boiler emission unit. This was done with the exception of all of the CAM requirements being kept in FGBOILERS12. Additionally, a separate FGMATSU12 table was created to house all of the common MATS requirements for the boilers. All requirements for EDTA and citrosolve have been removed as the units no longer burn any waste. The Conditions related to FGBOILER12 were accidentally added back into PTI No. 39-15A as well in	EUBOILER1, EUBOILER2 EUBOILER3, EUBYPRODUCT, FGBOILER12 Appendices 1-B, 3, 5

Permit to Install Number	ROP Revision Application Number - Issuance Date	Description of Equipment or Change	Corresponding Emission Unit(s) or Flexible Group(s)
		the associated Emission Units, so the Conditions were duplicative. AQD removed the duplicative and obsolete Conditions that were present in PTI No. 39-15A during this minor modification. During the Company's review, the Company requested to clarify in Appendix 3-E. PM CEMS, PM specification tests will be sent in the future to EGLE. This change would also allow updates to the installation and correlation plans to be submitted to and approved by EGLE.	

Appendix 7. Emission Calculations

Determination of Unit Specific NOx or SO_2 Mass Emissions for Those Units Where 40 CFR Part 75 NOx or SO_2 Mass Emissions Are Measured at a Common Stack

This Appendix is federally enforceable and was established pursuant to Rule 201(1)(a). This Appendix was originally established in the consent decree settling, "U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" and also pursuant Section 324.5503(b) of the Natural Resources and Environmental Protection Act, 1994 Act 451, as amended, and will remain in effect after termination of the consent decree. Definitions specific to this Appendix may be found in Appendix 1-B: Definitions. **(Act 451, Section 324.5503(b))**

For J.H. Campbell Units 1 and 2, NO_x mass emission rates are monitored at the associated common stacks via the use of NO_x concentration and flow CEMS. In addition, each of the preceding individual units are equipped with duct-level NO_x and diluent (i.e., CO_2) concentration CEMS to permit the determination of unit specific NO_x lb/MMBTU emission rates. The following procedures shall be used to calculate unit level NO_x mass emission rates for purposes of conducting rolling average NO_x lb/MMBTU calculations. If Campbell Units EUBOILER1 and EUBOILER2 elect to install unit level SO_2 CEMS only in lieu of installing both unit level SO_2 CEMS and Flow CEMS, the same procedure shall be followed for calculating unit level SO_2 mass emissions except that the value of K in Paragraph c. shall equal 1.660 x 10-7 (lb/scf)/ppm.

a. From 40 CFR Part 75, Appendix F, equation F-15 (already calculated and reported under Part 75), common stack heat input shall be calculated as follows:

$$HI = Q_w \times \frac{1}{F_c} \times \frac{\%CO_{2w}}{100}$$

Where,

HI = *Common stack hourly heat input rate during unit operation, MMBTU/hr*
Q_w = *Hourly average volumetric flow rate during unit operation, wet basis, scfh*
F_c = *Carbon-based F-factor, listed in 40 CFR 75, Appendix A, Section 3.3.5 for each fuel, scf/MMBTU*
$\%\ CO_{2w}$ = *Hourly concentration of CO_2 during unit operation, percent CO_2*

b. From 40 CFR Part 75, Appendix F, Equation F-21a (already calculated and reported under Part 75), individual unit heat input shall be calculated as follows:

$$HI_i = HI_{CS} \times \frac{T_{CS}}{t_i} \times \left[\frac{MW_i \times t_i}{\sum_{i=1}^{n} MW_i \times t_i}\right]$$

Where,

HI_i = *Heat input rate for a unit, MMBTU/hr*
HI_{CS} = *Heat input rate at the common stack, MMBTU/hr*
MW_i = *Gross electrical output, MWe*
t_c = *Unit operating time, hour or fraction of an hour*
t_{CS} = *Common stack or common pipe operating time, hour or fraction of an hour*
n = *Total number of units using the common stack*
i = *Designation of a particular unit*

c. From 40 CFR Part 75, Appendix F, Equation F-6 (already calculated and reported under Part 75), individual unit NO_x lb/MMBTU emission rates shall be calculated as follows:

$$E = K \times C_h \times F_c \times \frac{100}{\%CO_2}$$

Where,

E = *Pollutant emission rate during unit operation, lb/MMBTU*
K = *$1.194x10^{-7}$ for NO_x (lb/scj)/ppm*
C_h = *Hourly average NO_x concentration during unit operation, ppm*
F_c = *Carbon-based F-factor, listed in 40 CFR 75, Appendix A, Section 3.3.5 for each fuel, scf/MMBTU*
$\%CO_2$ = *Hourly concentration of CO_2 during unit operation, percent CO_2*

d. To calculate unit level NO_x mass emissions in each operating hour (not calculated or reported under Part 75), the following calculation shall be performed:

$$\boldsymbol{E_{(NOx)h} = E \times HI_i}$$

Where,

$E_{(NOx)h}$ = *NO_x mass emission rate for hour "h", in lbs/hr*
E = *Pollutant emission rate during unit operation, lb/MMBTU*
HI_i = *Heat input rate for a unit, MMBTU/hr*

$$\boldsymbol{M_{(NOx)h} = E_{(NOx)h} \times t_h}$$

Where,

$M_{(NOx)h}$ = *NO_x mass emissions for hour "h", lbs*
$E_{(NOx)h}$ = *NO_x mass emission rate for hour "h", in lbs/hr*
t_h = *Unit operating time for hour "h", in hours or fraction of an hour*

e. The preceding unit specific NO_x mass emissions data shall then be used in accordance with Paragraphs 5, 6, and 7 of the CD (refer to Appendix 1-B) to calculate 30-day rolling, 90-day rolling and 365-day rolling NO_x lb/MMBTU emission rates, respectively (as applicable).

Appendix 8. Reporting

A. Annual, Semiannual, and Deviation Certification Reporting

The permittee shall use the EGLE, AQD, Report Certification form (EQP 5736) and EGLE, AQD, Deviation Report form (EQP 5737) for the annual, semiannual and deviation certification reporting referenced in the Reporting Section of the Source-Wide, Emission Unit and/or Flexible Group Special Conditions. Alternative formats must meet the provisions of Rule 213(4)(c) and Rule 213(3)(c)(i), respectively, and be approved by the AQD District Supervisor.

B. Other Reporting

The permittee shall use the following approved formats and procedures for the reporting requirements referenced in. EUBOILER3, EUCOALHAND, FGMATS_U12, and FGMATS_U3. For other reporting requirements, specific reporting requirement formats and procedures are detailed in Part A or the appropriate Requirement Tables. Alternative formats must be approved by the AQD District Supervisor.

Standards of Performance for New Sources (NSPS) reporting requirements for EUBOILER3 and EUCOALHAND include, but are not necessarily limited to, the following:

Notification requirements per Section 60.7 of 40 CFR Part 60, Subpart A;

60.7(a)(1)	Notification of the date of construction or reconstruction of an affected facility is commenced, postmarked no later than 30 days after such date.
60.7(a)(2)	Notification of the date or anticipated date of the initial startup of an affected facility, postmarked not more than 60 nor less than 30 days prior to such date.
60.7(a)(3)	Notification of the actual date of initial startup of an affected facility, postmarked within 15 days after such date.
60.7(a)(4)	Notification of any physical or operational change to an existing facility which may increase the emission rate of any air pollutant to which a standard applies, unless that change is specifically exempted under an applicable subpart or in Section 60.14(e). This notice shall be postmarked 60 days (or as soon as practicable) before the change is commenced.

Notifications of reconstruction activities per Section 60.15 of 40 CFR, Part 60, Subpart A; and

60.15(d)	If an owner or operator of an existing facility proposes to replace components and the fixed capital cost of the new components exceeds 50% of the fixed capital cost that would be required to construct a comparable entirely new facility, notification of the proposed replacements, postmarked 60 days (or as soon as practicable) before the construction of the replacements is commenced.

Reporting requirements per 40 CFR Part 60, Subpart D.

Excess emission (EE) reports and monitoring system performance (MSP) reports shall be submitted every quarter. All quarterly reports shall be postmarked by the 30th day following the end of each calendar quarter. Each EE and MSP report shall include the information required in Section 60.7(c). Periods of excess emission and monitoring system downtime that shall be reported are defined as followed:

1. Opacity: EE are defined as any 6-minute period during which the average opacity of emissions exceeds 20% opacity, except that one 6-minute average per hour of up to 27% need not be reported.

2. SO_2: EE are defined as any 3-hour period during which the average emissions (arithmetic average of 3 contiguous one-hour periods) of SO_2 as measured by a CEMS exceeded the applicable standard under Section 60.43, per Section 60.45(g)(2).

3. NO_x: EE are defined as any 3-hour period during which the average emissions (arithmetic average of 3 contiguous one-hour periods) of NO_x as measured by a CEMS exceeded the applicable standard under Section 60.44, Section 60.45(g)(3).

Appendix 9. Acid Rain Permit

PHASE II ACID RAIN PERMIT
Permit No. MI-AR-1710-2020

Permittee	Consumers Energy – J.H. Campbell Plant
Address	17000 Croswell, West Olive, MI
SRN	B2835
ORIS Code	1710
Issue Date	February 4, 2020
Effective	Issuance date of this facility's Renewable Operating Permit at the facility in accordance with 40 CFR 72.73.
Expiration	This permit shall expire when the facility's Renewable Operating Permit expires, in accordance with 40 CFR 72.73.
ROP No.	MI-ROP-B2835-2020

The Acid Rain Permit Contents

1. A statement of basis prepared by the Air Quality Division (AQD) containing:

   References to statutory and regulatory authorities, and with comments, notes, and justification that apply to the source in general;

2. Terms and conditions including:

   A table of sulfur dioxide allowances to be allocated during the term of the permit, if applicable, authorized by this permit during Phase II. Unless they are subject to Sections 405(g)(2) or (3) of the federal Clean Air Act, new units are not allocated allowances in 40 CFR Part 73 and must obtain allowances by other means (Section 403(e) of the federal Clean Air Act);

   Comments, notes and justifications regarding permit decisions and changes made to the permit application forms during the review process, and any additional requirements; and,

   Any applicable nitrogen oxides compliance plan. Unless they are coal fired utility units regulated pursuant to Sections 404, 405, or 409 of the federal Clean Air Act, new units are not subject to the acid rain nitrogen oxides requirements (40 CFR 76.1(a)).

3. The permit application that this source submitted, as corrected by the AQD. The owners and operators of the source must comply with the standard requirements and special provisions set forth in the application.

Statement of Basis

Statutory and Regulatory Authorities.

In accordance with the Natural Resources and Environmental Protection Act, 1994 PA 451 and Titles IV and V of the federal Clean Air Act, the Michigan Department of Environment, Great Lakes, and Energy, Air Quality Division (AQD), issues this permit pursuant to the provisions of R 336.1210 to R 336.1218, and R 336.1299(d).

For further information contact:

Mr. Brian Carley
Environmental Quality Specialist
Michigan Department of Environment, Great Lakes, and Energy
Air Quality Division, Jackson District Office
State Office Building, 4th Floor
301 East Louis B. Glick Highway
Jackson, Michigan 49201-1556

Telephone: 517-416-4631
Facsimile: 517-780-7855

There are no comments, notes and/or justification that apply to the source in general for this section.

Terms and Conditions:

Phase II Sulfur Dioxide Allowance Allocation and Nitrogen Oxides Requirements for each affected unit.

		2020	2021	2022	2023	2024
Unit 1	SO_2 allowances	8113	8113	8113	8113	8113
	NOx Emission Limits	Pursuant to 40 CFR part 76, the State of Michigan Department of Environment, Great Lakes, and Energy, Air Quality Division approves a NOx standard emissions limitation compliance plan for unit 1. The NOx compliance plan is effective beginning 2017. Under the NOx compliance plan, this unit's annual average NOx emissions rate for each year, determined in accordance with 40 CFR part 75, shall not exceed the applicable emission limitation, under 40 CFR 76.7(a)(2), of **0.45 lb/MMBTU** for Phase I tangentially fired boilers. In addition to the described NOx compliance plan, this unit shall comply with all other applicable requirements of 40 CFR part 76, including the duty to reapply for a NOx compliance plan and requirements covering excess emissions.				

		2020	2021	2022	2023	2024
Unit 2	SO_2 allowances	9702	9702	9702	9702	9702
	NOx Emission Limits	Pursuant to 40 CFR part 76, the State of Michigan Department of Environment, Great Lakes, and Energy, Air Quality Division approves a NOx standard emissions limitation compliance plan for unit 2. The NOx compliance plan is effective beginning 2017. Under the NOx compliance plan, this unit's annual average NOx emissions rate for each year, determined in accordance with 40 CFR part 75, shall not exceed the applicable emission limitation, under 40 CFR 76.7(a)(2), of **0.68 lb/MMBTU** for cell burner boilers. In addition to the described NOx compliance plan, this unit shall comply with all other applicable requirements of 40 CFR part 76, including the duty to reapply for a NOx compliance plan and requirements covering excess emissions.				

Terms and Conditions (cont.):

		2020	2021	2022	2023	2024
Unit 3	SO_2 allowances	27529	27529	27529	27529	27529
	NOx Emission Limits	Pursuant to 40 CFR part 76, the State of Michigan Department of Environment, Great Lakes, and Energy, Air Quality Division approves a NOx standard emissions limitation compliance plan for unit 3. The NOx compliance plan is effective beginning 2017. Under the NOx compliance plan, this unit's annual average NOx emissions rate for each year, determined in accordance with 40 CFR part 75, shall not exceed the applicable emission limitation, under 40 CFR 76.7(a)(2), of **0.46 lb/MMBTU** for Phase II dry bottom wall-fired boilers. In addition to the described NOx compliance plan, this unit shall comply with all other applicable requirements of 40 CFR part 76, including the duty to reapply for a NOx compliance plan and requirements covering excess emissions.				

Comments, notes and justifications regarding permit decisions, and changes made to the permit application forms during the review process:

Permit Application: (attached)

Acid Rain Permit Application submitted February 27, 2018
Acid Rain NOx Compliance Plan submitted July 5, 2017

United States
Environmental Protection Agency
Acid Rain Program

OMB No. 2060-0258
Approval expires 11/30/2018

Acid Rain Permit Application

For more information, see instructions and 40 CFR 72.30 and 72.31.

This submission is: ☐ new ☐ revised ☒ for ARP permit renewal

STEP 1

Identify the facility name, State, and plant (ORIS) code.

J.H. Campbell Plant Facility (Source) Name	MI State	1710 Plant Code

STEP 2

Enter the unit ID# for every affected unit at the affected source in column "a."

a	b
Unit ID#	Unit Will Hold Allowances in Accordance with 40 CFR 72.9(c)(1)
Unit 1	**Yes**
Unit 2	**Yes**
Unit 3	**Yes**
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes

EPA Form 7610-16 (Revised 12-2016)

J.H. Campbell Plant
Facility (Source) Name (from STEP 1)

STEP 3

Read the standard requirements.

Permit Requirements

(1) The designated representative of each affected source and each affected unit at the source shall:
  (i) Submit a complete Acid Rain permit application (including a compliance plan) under 40 CFR part 72 in accordance with the deadlines specified in 40 CFR 72.30; and
  (ii) Submit in a timely manner any supplemental information that the permitting authority determines is necessary in order to review an Acid Rain permit application and issue or deny an Acid Rain permit;
(2) The owners and operators of each affected source and each affected unit at the source shall:
  (i) Operate the unit in compliance with a complete Acid Rain permit application or a superseding Acid Rain permit issued by the permitting authority; and
  (ii) Have an Acid Rain Permit.

Monitoring Requirements

(1) The owners and operators and, to the extent applicable, designated representative of each affected source and each affected unit at the source shall comply with the monitoring requirements as provided in 40 CFR part 75.
(2) The emissions measurements recorded and reported in accordance with 40 CFR part 75 shall be used to determine compliance by the source or unit, as appropriate, with the Acid Rain emissions limitations and emissions reduction requirements for sulfur dioxide and nitrogen oxides under the Acid Rain Program.
(3) The requirements of 40 CFR part 75 shall not affect the responsibility of the owners and operators to monitor emissions of other pollutants or other emissions characteristics at the unit under other applicable requirements of the Act and other provisions of the operating permit for the source.

Sulfur Dioxide Requirements

(1) The owners and operators of each source and each affected unit at the source shall:
  (i) Hold allowances, as of the allowance transfer deadline, in the source's compliance account (after deductions under 40 CFR 73.34(c)), not less than the total annual emissions of sulfur dioxide for the previous calendar year from the affected units at the source; and
  (ii) Comply with the applicable Acid Rain emissions limitations for sulfur dioxide.
(2) Each ton of sulfur dioxide emitted in excess of the Acid Rain emissions limitations for sulfur dioxide shall constitute a separate violation of the Act.
(3) An affected unit shall be subject to the requirements under paragraph (1) of the sulfur dioxide requirements as follows:
  (i) Starting January 1, 2000, an affected unit under 40 CFR 72.6(a)(2); or
  (ii) Starting on the later of January 1, 2000 or the deadline for monitor certification under 40 CFR part 75, an affected unit under 40 CFR 72.6(a)(3).
(4) Allowances shall be held in, deducted from, or transferred among Allowance Tracking System accounts in accordance with the Acid Rain Program.
(5) An allowance shall not be deducted in order to comply with the requirements under paragraph (1) of the sulfur dioxide requirements prior to the calendar year for which the allowance was allocated.
(6) An allowance allocated by the Administrator under the Acid Rain Program is a limited authorization to emit sulfur dioxide in accordance with the Acid Rain Program. No provision of the Acid Rain Program, the Acid Rain permit application, the Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.
(7) An allowance allocated by the Administrator under the Acid Rain Program does not constitute a property right.

Nitrogen Oxides Requirements

The owners and operators of the source and each affected unit at the source shall comply with the applicable Acid Rain emissions limitation for nitrogen oxides.

J.H. Campbell Plant
Facility (Source) Name (from STEP 1)

STEP 3, Cont'd.

Excess Emissions Requirements

(1) The designated representative of an affected source that has excess emissions in any calendar year shall submit a proposed offset plan, as required under 40 CFR part 77.
(2) The owners and operators of an affected source that has excess emissions in any calendar year shall:
(i) Pay without demand the penalty required, and pay upon demand the interest on that penalty, as required by 40 CFR part 77; and
(ii) Comply with the terms of an approved offset plan, as required by 40 CFR part 77.

Recordkeeping and Reporting Requirements

(1) Unless otherwise provided, the owners and operators of the source and each affected unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time prior to the end of 5 years, in writing by the Administrator or permitting authority:
(i) The certificate of representation for the designated representative for the source and each affected unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation, in accordance with 40 CFR 72.24; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation changing the designated representative;
(ii) All emissions monitoring information, in accordance with 40 CFR part 75, provided that to the extent that 40 CFR part 75 provides for a 3-year period for recordkeeping, the 3-year period shall apply.
(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the Acid Rain Program; and,
(iv) Copies of all documents used to complete an Acid Rain permit application and any other submission under the Acid Rain Program or to demonstrate compliance with the requirements of the Acid Rain Program.
(2) The designated representative of an affected source and each affected unit at the source shall submit the reports and compliance certifications required under the Acid Rain Program, including those under 40 CFR part 72 subpart I and 40 CFR part 75.

Liability

(1) Any person who knowingly violates any requirement or prohibition of the Acid Rain Program, a complete Acid Rain permit application, an Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8, including any requirement for the payment of any penalty owed to the United States, shall be subject to enforcement pursuant to section 113(c) of the Act.
(2) Any person who knowingly makes a false, material statement in any record, submission, or report under the Acid Rain Program shall be subject to criminal enforcement pursuant to section 113(c) of the Act and 18 U.S.C. 1001.
(3) No permit revision shall excuse any violation of the requirements of the Acid Rain Program that occurs prior to the date that the revision takes effect.
(4) Each affected source and each affected unit shall meet the requirements of the Acid Rain Program.
(5) Any provision of the Acid Rain Program that applies to an affected source (including a provision applicable to the designated representative of an affected source) shall also apply to the owners and operators of such source and of the affected units at the source.
(6) Any provision of the Acid Rain Program that applies to an affected unit (including a provision applicable to the designated representative of an affected unit) shall also apply to the owners and operators of such unit.
(7) Each violation of a provision of 40 CFR parts 72, 73, 74, 75, 76, 77, and 78 by an affected source or affected unit, or by an owner or operator or designated representative of such source or unit, shall be a separate violation of the Act.

J.H. Campbell Plant
Facility (Source) Name (from STEP 1)

STEP 3, Cont'd.

Effect on Other Authorities

No provision of the Acid Rain Program, an Acid Rain permit application, an Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8 shall be construed as:

(1) Except as expressly provided in title IV of the Act, exempting or excluding the owners and operators and, to the extent applicable, the designated representative of an affected source or affected unit from compliance with any other provision of the Act, including the provisions of title I of the Act relating to applicable National Ambient Air Quality Standards or State Implementation Plans;

(2) Limiting the number of allowances a source can hold; *provided*, that the number of allowances held by the source shall not affect the source's obligation to comply with any other provisions of the Act;

(3) Requiring a change of any kind in any State law regulating electric utility rates and charges, affecting any State law regarding such State regulation, or limiting such State regulation, including any prudence review requirements under such State law;

(4) Modifying the Federal Power Act or affecting the authority of the Federal Energy Regulatory Commission under the Federal Power Act; or,

(5) Interfering with or impairing any program for competitive bidding for power supply in a State in which such program is established.

STEP 4
Read the certification statement, sign, and date.

Certification

I am authorized to make this submission on behalf of the owners and operators of the affected source or affected units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

John P. Broschak, Designated Representative Name	
Signature: John P. Broschak	Date: 1-24-18

EPA Form 7610-16 (Revised 12-2016)

EPA

United States
Environmental Protection Agency
Acid Rain Program

OMB No. 2060-0258
Approval expires 11/30/2018

Acid Rain NO_X Compliance Plan

For more information, see instructions and refer to 40 CFR 76.9

Page 1

This submission is: ☐ New ☒ Revised

Page 1 of 1

STEP 1
Indicate plant name, State, and Plant code from the current Certificate of Representation covering the facility.

Plant Name	State	Plant Code
J.H. Campbell	MI	1710

STEP 2

Identify each affected Group 1 and Group 2 boiler using the unit IDs from the current Certificate of Representation covering the facility. Also indicate the boiler type: "CB" for cell burner, "CY" for cyclone, "DBW" for dry bottom wall-fired, "T" for tangentially fired, "V" for vertically fired, and "WB" for wet bottom, and select the compliance option for each unit by making an 'X' in the appropriate row and column.

	ID# 1 Type T	ID# 2 Type CB	ID# 3 Type DBW	ID# Type	ID# Type	ID# Type
(a) Standard annual average emission limitation of 0.50 lb/mmBtu (for Phase I dry bottom wall-fired boilers)						
(b) Standard annual average emission limitation of 0.45 lb/mmBtu (for Phase I tangentially fired boilers)	X					
(c) Standard annual average emission limitation of 0.46 lb/mmBtu (for Phase II dry bottom wall-fired boilers)			X			
(d) Standard annual average emission limitation of 0.40 lb/mmBtu (for Phase II tangentially fired boilers)						
(e) Standard annual average emission limitation of 0.68 lb/mmBtu (for cell burner boilers)		X				
(f) Standard annual average emission limitation of 0.86 lb/mmBtu (for cyclone boilers)						
(g) Standard annual average emission limitation of 0.80 lb/mmBtu (for vertically fired boilers)						
(h) Standard annual average emission limitation of 0.84 lb/mmBtu (for wet bottom boilers)						
(i) NO_2 Averaging Plan (include NO_X Averaging form)						
(j) Common stack pursuant to 40 CFR 75.17(a)(2)(i)(A) (check the standard emission limitation box above for most stringent limitation applicable to any unit utilizing stack)						
(k) Common stack pursuant to 40 CFR 75.17(a)(2)(i)(B) with NO_2 Averaging (check the NO_2 Averaging Plan box and include NO_X Averaging Form))						
(l) EPA-approved common stack apportionment method pursuant to 40 CFR 75.17(a)(2)(i)(C), (a)(2)(ii)(B), or (b)(2)						

EPA Form 7610-28 (Revised 12-2016)

J.H. Campbell
Plant Name (from Step 1)

STEP 3
Identify the first calendar year in which this plan will apply.

January 1, 2017

STEP 4
Read the special provisions and certification, enter the name of the designated representative, sign and date.

Special Provisions

General

This source is subject to the standard requirements in 40 CFR 72.9. These requirements are listed in this source's Acid Rain Permit.

Certification

I am authorized to make this submission on behalf of the owners and operators of the affected source or affected units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name John P. Broschak

Signature John P. Broschak Date 6/29/17

EPA Form 7610-28 (Revised 12-2016)

Appendix 10: Cross State Air Pollution Rule (CSAPR) Trading Program Title V Requirements

Description of CSAPR Monitoring Provisions

The CSAPR subject units, and the unit-specific monitoring provisions, at this source are identified in the following tables. These units are subject to the requirements for the CSAPR NO_X Annual Trading Program, CSAPR NO_X Ozone Season Group 2 Trading Program, and CSAPR SO_2 Group 1 Trading Program, which are included below as Sections I, II, and III, respectively.

Each unit will use one of the following as the monitoring methodology for each parameter as provided below and shall comply with the general monitoring, recordkeeping, reporting and other requirements in conditions 1 through 5 below and in paragraph (b) of Sections I, II, and III:

- Continuous emission monitoring system or systems (CEMS) requirements pursuant to 40 CFR Part 75, Subpart B (for SO_2 monitoring) or 40 CFR Part 75, Subpart H (for NO_X monitoring)
- Excepted monitoring system requirements for gas- and oil-fired units pursuant to 40 CFR Part 75, Appendix D
- Excepted monitoring system requirements for gas- and oil-fired peaking units pursuant to 40 CFR Part 75, Appendix E
- Low Mass Emissions excepted monitoring (LME) requirements for gas- and oil-fired units pursuant to 40 CFR 75.19
- USEPA-approved alternative monitoring system requirements pursuant to 40 CFR Part 75, Subpart E

Unit ID: 1	
Parameter	Monitoring Methodology
SO_2	Continuous emission monitoring system or systems (CEMS) requirements pursuant to 40 CFR Part 75, Subpart B
NO_X	Continuous emission monitoring system or systems (CEMS) requirements pursuant to 40 CFR Part 75, Subpart H
Heat Input	Continuous emission monitoring system or systems (CEMS) requirements pursuant to 40 CFR Part 75, Subpart B (for SO2 monitoring) or 40 CFR Part 75, Subpart H (for NOX monitoring)

Unit ID: 2	
Parameter	Monitoring Methodology
SO_2	Continuous emission monitoring system or systems (CEMS) requirements pursuant to 40 CFR Part 75, Subpart B
NO_X	Continuous emission monitoring system or systems (CEMS) requirements pursuant to 40 CFR Part 75, Subpart H
Heat Input	Continuous emission monitoring system or systems (CEMS) requirements pursuant to 40 CFR Part 75, Subpart B (for SO2 monitoring) or 40 CFR Part 75, Subpart H (for NOX monitoring)

Unit ID: 3	
Parameter	Monitoring Methodology
SO_2	Continuous emission monitoring system or systems (CEMS) requirements pursuant to 40 CFR Part 75, Subpart B
NO_X	Continuous emission monitoring system or systems (CEMS) requirements pursuant to 40 CFR Part 75, Subpart H
Heat Input	Continuous emission monitoring system or systems (CEMS) requirements pursuant to 40 CFR Part 75, Subpart B (for SO2 monitoring) or 40 CFR Part 75, Subpart H (for NOX monitoring)

1. The above description of the monitoring used by a unit does not change, create an exemption from, or otherwise affect the monitoring, recordkeeping, and reporting requirements applicable to the unit under 40 CFR 97.430 through 97.435 (CSAPR NO_X Annual Trading Program), 97.830 through 97.835 (CSAPR NO_X Ozone Season Group 2 Trading Program), and 97.630 through 97.635 (CSAPR SO_2 Group 1 Trading Program). The monitoring, recordkeeping and reporting requirements applicable to each unit are included below in the standard conditions for the applicable CSAPR trading programs.

2. Owners and operators must submit to the Administrator a monitoring plan for each unit in accordance with 40 CFR 75.53, 75.62 and 75.73, as applicable. The monitoring plan for each unit is available at the USEPA's website at https://www.epa.gov/airmarkets/clean-air-markets-monitoring-plans-part-75-sources.

3. Owners and operators that want to use an alternative monitoring system must submit to the Administrator a petition requesting approval of the alternative monitoring system in accordance with 40 CFR Part 75, Subpart E and 40 CFR 75.66 and 97.435 (CSAPR NO_X Annual Trading Program), 97.835 (CSAPR NO_X Ozone Season Group 2 Trading Program), and/or 97.635 (CSAPR SO_2 Group 1 Trading Program). The Administrator's response approving or disapproving any petition for an alternative monitoring system is available on the USEPA's website at https://www.epa.gov/airmarkets/part-75-petition-responses.

4. Owners and operators that want to use an alternative to any monitoring, recordkeeping, or reporting requirement under 40 CFR 97.430 through 97.434 (CSAPR NO_X Annual Trading Program), 97.830 through 97.834 (CSAPR NO_X Ozone Season Group 2 Trading Program), and/or 97.630 through 97.634 (CSAPR SO_2 Group 1 Trading Program) must submit to the Administrator a petition requesting approval of the alternative in accordance with 40 CFR 75.66 and 97.435 (CSAPR NO_X Annual Trading Program), 97.835 (CSAPR NO_X Ozone Season Group 2 Trading Program), and/or 97.635 (CSAPR SO_2 Group 1 Trading Program). The Administrator's response approving or disapproving any petition for an alternative to a monitoring, recordkeeping, or reporting requirement is available on the USEPA's website at https://www.epa.gov/airmarkets/part-75-petition-responses.

5. The descriptions of monitoring applicable to the unit included above meet the requirement of 40 CFR 97.430 through 97.434 (CSAPR NO_X Annual Trading Program), 97.830 through 97.834 (CSAPR NO_X Ozone Season Group 2 Trading Program), and 97.630 through 97.634 (CSAPR SO_2 Group 1 Trading Program), and therefore minor permit modification procedures, in accordance with 40 CFR 70.7(e)(2)(i)(B) or 71.7(e)(1)(i)(B), may be used to add or change this unit's monitoring system description.

SECTION I: CSAPR NO_X Annual Trading Program requirements (40 CFR 97.406)

(a) Designated representative requirements.
The owners and operators shall comply with the requirement to have a designated representative, and may have an alternate designated representative, in accordance with 40 CFR 97.413 through 97.418.

(b) Emissions monitoring, reporting, and recordkeeping requirements.
(1) The owners and operators, and the designated representative, of each CSAPR NO_X Annual source and each CSAPR NO_X Annual unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of 40 CFR 97.430 (general requirements, including installation, certification, and data accounting, compliance deadlines, reporting data, prohibitions, and long-term cold storage), 97.431 (initial monitoring system certification and recertification procedures), 97.432 (monitoring system out-of-control periods), 97.433 (notifications concerning monitoring), 97.434 (recordkeeping and reporting, including monitoring plans, certification applications, quarterly reports, and compliance certification), and 97.435 (petitions for alternatives to monitoring, recordkeeping, or reporting requirements).
(2) The emissions data determined in accordance with 40 CFR 97.430 through 97.435 shall be used to calculate allocations of CSAPR NO_X Annual allowances under 40 CFR 97.411(a)(2) and (b) and 97.412 and to determine compliance with the CSAPR NO_X Annual emissions limitation and assurance provisions under paragraph (c) below, provided that, for each monitoring location from which mass emissions are reported, the mass emissions amount used in calculating such allocations and determining such compliance shall be the mass emissions amount for the monitoring location determined in accordance with 40 CFR 97.430 through 97.435 and rounded to the nearest ton, with any fraction of a ton less than 0.50 being deemed to be zero.

(c) NO_X emissions requirements.
(1) CSAPR NO_X Annual emissions limitation.
(i). As of the allowance transfer deadline for a control period in a given year, the owners and operators of each CSAPR NO_X Annual source and each CSAPR NO_X Annual unit at the source shall hold, in the source's compliance account, CSAPR NO_X Annual allowances available for deduction for such control period under 40 CFR 97.424(a) in an amount not less than the tons of total NO_X emissions for such control period from all CSAPR NO_X Annual units at the source.

(ii). If total NO_X emissions during a control period in a given year from the CSAPR NO_X Annual units at a CSAPR NO_X Annual source are in excess of the CSAPR NO_X Annual emissions limitation set forth in paragraph (c)(1)(i) above, then:

(A). The owners and operators of the source and each CSAPR NO_X Annual unit at the source shall hold the CSAPR NO_X Annual allowances required for deduction under 40 CFR 97.424(d); and

(B). The owners and operators of the source and each CSAPR NO_X Annual unit at the source shall pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act, and each ton of such excess emissions and each day of such control period shall constitute a separate violation of 40 CFR Part 97, Subpart AAAAA and the Clean Air Act.

(2) CSAPR NO_X Annual assurance provisions.

(i). If total NO_X emissions during a control period in a given year from all CSAPR NO_X Annual units at CSAPR NO_X Annual sources in the state and Indian country within the borders of such State exceed the state assurance level, then the owners and operators of such sources and units in each group of one or more sources and units having a common designated representative for such control period, where the common designated representative's share of such NO_X emissions during such control period exceeds the common designated representative's assurance level for the state and such control period, shall hold (in the assurance account established for the owners and operators of such group) CSAPR NO_X Annual allowances available for deduction for such control period under 40 CFR 97.425(a) in an amount equal to two times the product (rounded to the nearest whole number), as determined by the Administrator in accordance with 40 CFR 97.425(b), of multiplying— (A) The quotient of the amount by which the common designated representative's share of such NO_X emissions exceeds the common designated representative's assurance level divided by the sum of the amounts, determined for all common designated representatives for such sources and units in the state and Indian country within the borders of such state for such control period, by which each common designated representative's share of such NO_X emissions exceeds the respective common designated representative's assurance level; and (B) The amount by which total NO_X emissions from all CSAPR NO_X Annual units at CSAPR NO_X Annual sources in the state and Indian country within the borders of such state for such control period exceed the state assurance level.

(ii). The owners and operators shall hold the CSAPR NO_X Annual allowances required under paragraph (c)(2)(i) above, as of midnight of November 1 (if it is a business day), or midnight of the first business day thereafter (if November 1 is not a business day), immediately after such control period.

(iii). Total NO_X emissions from all CSAPR NO_X Annual units at CSAPR NO_X Annual sources in the State and Indian country within the borders of such state during a control period in a given year exceed the state assurance level if such total NO_X emissions exceed the sum, for such control period, of the state NO_X Annual trading budget under 40 CFR 97.410(a) and the state's variability limit under 40 CFR 97.410(b).

(iv). It shall not be a violation of 40 CFR Part 97, Subpart AAAAA or of the Clean Air Act if total NO_X emissions from all CSAPR NO_X Annual units at CSAPR NO_X Annual sources in the State and Indian country within the borders of such State during a control period exceed the state assurance level or if a common designated representative's share of total NO_X emissions from the CSAPR NO_X Annual units at CSAPR NO_X Annual sources in the state and Indian country within the borders of such state during a control period exceeds the common designated representative's assurance level.

(v). To the extent the owners and operators fail to hold CSAPR NO_X Annual allowances for a control period in a given year in accordance with paragraphs (c)(2)(i) through (iii) above,

(A). The owners and operators shall pay any fine, penalty, or assessment or comply with any other remedy imposed under the Clean Air Act; and

(B). Each CSAPR NO_X Annual allowance that the owners and operators fail to hold for such control period in accordance with paragraphs (c)(2)(i) through (iii) above and each day of such control period shall constitute a separate violation of 40 CFR Part 97, Subpart AAAAA and the Clean Air Act.

(3) Compliance periods.

(i). A CSAPR NO_X Annual unit shall be subject to the requirements under paragraph (c)(1) above for the control period starting on the later of January 1, 2015, or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.430(b) and for each control period thereafter.

(ii). A CSAPR NO_X Annual unit shall be subject to the requirements under paragraph (c)(2) above for the control period starting on the later of January 1, 2017 or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.430(b) and for each control period thereafter.

(4) Vintage of allowances held for compliance.

(i). A CSAPR NO_X Annual allowance held for compliance with the requirements under paragraph (c)(1)(i) above for a control period in a given year must be a CSAPR NO_X Annual allowance that was allocated for such control period or a control period in a prior year.

(ii). A CSAPR NO_X Annual allowance held for compliance with the requirements under paragraphs (c)(1)(ii)(A) and (2)(i) through (iii) above for a control period in a given year must be a CSAPR NO_X Annual allowance that was allocated for a control period in a prior year or the control period in the given year or in the immediately following year.

(5) Allowance Management System requirements. Each CSAPR NO_X Annual allowance shall be held in, deducted from, or transferred into, out of, or between Allowance Management System accounts in accordance with 40 CFR Part 97, Subpart AAAAA.

(6) Limited authorization. A CSAPR NO_X Annual allowance is a limited authorization to emit one ton of NO_X during the control period in one year. Such authorization is limited in its use and duration as follows:

(i). Such authorization shall only be used in accordance with the CSAPR NO_X Annual Trading Program; and

(ii). Notwithstanding any other provision of 40 CFR Part 97, the Administrator has the authority to terminate or limit the use and duration of such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.

(7) Property right. A CSAPR NO_X Annual allowance does not constitute a property right.

(d) Title V permit revision requirements.

(1) No title V permit revision shall be required for any allocation, holding, deduction, or transfer of CSAPR NO_X Annual allowances in accordance with 40 CFR Part 97, Subpart AAAAA.

(2) This permit incorporates the CSAPR emissions monitoring, recordkeeping and reporting requirements pursuant to 40 CFR 97.430 through 97.435, and the requirements for a continuous emission monitoring system (pursuant to 40 CFR Part 75, Subparts B and H), an excepted monitoring system (pursuant to 40 CFR Part 75, Appendices D and E), a low mass emissions excepted monitoring methodology (pursuant to 40 CFR 75.19), and an alternative monitoring system (pursuant to 40 CFR Part 75, Subpart E). Therefore, the Description of CSAPR Monitoring Provisions table for units identified in this permit may be added to, or changed, in this title V permit using minor permit modification procedures in accordance with 40 CFR 97.406(d)(2) and 70.7(e)(2)(i)(B) or 71.7(e)(1)(i)(B).

(e) Additional recordkeeping and reporting requirements.

(1) Unless otherwise provided, the owners and operators of each CSAPR NO_X Annual source and each CSAPR NO_X Annual unit at the source shall keep on site at the source each of the following documents (in hardcopy or electronic format) for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the Administrator.

(i). The certificate of representation under 40 CFR 97.416 for the designated representative for the source and each CSAPR NO_X Annual unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such certificate of representation and documents are superseded because of the submission of a new certificate of representation under 40 CFR 97.416 changing the designated representative.

(ii). All emissions monitoring information, in accordance with 40 CFR Part 97, Subpart AAAAA.

(iii). Copies of all reports, compliance certifications, and other submissions and all records made or required under, or to demonstrate compliance with the requirements of, the CSAPR NO_X Annual Trading Program.

(2) The designated representative of a CSAPR NO_X Annual source and each CSAPR NO_X Annual unit at the source shall make all submissions required under the CSAPR NO_X Annual Trading Program, except as provided in 40 CFR 97.418. This requirement does not change, create an exemption from, or otherwise affect the responsible official submission requirements under a title V operating permit program in 40 CFR Parts 70 and 71.

(f) Liability.

(1) Any provision of the CSAPR NO_X Annual Trading Program that applies to a CSAPR NO_X Annual source or the designated representative of a CSAPR NO_X Annual source shall also apply to the owners and operators of such source and of the CSAPR NO_X Annual units at the source.

(2) Any provision of the CSAPR NO_X Annual Trading Program that applies to a CSAPR NO_X Annual unit or the designated representative of a CSAPR NO_X Annual unit shall also apply to the owners and operators of such unit.

(g) Effect on other authorities.

No provision of the CSAPR NO_X Annual Trading Program or exemption under 40 CFR 97.405 shall be construed as exempting or excluding the owners and operators, and the designated representative, of a CSAPR NO_X Annual source or CSAPR NO_X Annual unit from compliance with any other provision of the applicable, approved state implementation plan, a federally enforceable permit, or the Clean Air Act.

(h) Effect on units in Indian country.

Notwithstanding the provisions of paragraphs (a) through (g) above, paragraphs (a) through (g) shall be deemed not to impose any requirements on any source or unit, or any owner, operator, or designated representative with regard to any source or unit, in Indian country within the borders of the state.

SECTION II: CSAPR NO_X Ozone Season Group 2 Trading Program Requirements (40 CFR 97.806)

(a) Designated representative requirements.

The owners and operators shall comply with the requirement to have a designated representative, and may have an alternate designated representative, in accordance with 40 CFR 97.813 through 97.818.

(b) Emissions monitoring, reporting, and recordkeeping requirements.

(1) The owners and operators, and the designated representative, of each CSAPR NO_X Ozone Season Group 2 source and each CSAPR NO_X Ozone Season Group 2 unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of 40 CFR 97.830 (general requirements, including installation, certification, and data accounting, compliance deadlines, reporting data, prohibitions, and long-term cold storage), 97.831 (initial monitoring system certification and recertification procedures), 97.832 (monitoring system out-of-control periods), 97.833 (notifications concerning monitoring), 97.834 (recordkeeping and reporting, including monitoring plans, certification applications, quarterly reports, and compliance certification), and 97.835 (petitions for alternatives to monitoring, recordkeeping, or reporting requirements).

(2) The emissions data determined in accordance with 40 CFR 97.830 through 97.835 shall be used to calculate allocations of CSAPR NO_X Ozone Season Group 2 allowances under 40 CFR 97.811(a)(2) and (b) and 97.812 and to determine compliance with the CSAPR NO_X Ozone Season Group 2 emissions limitation and assurance provisions under paragraph (c) below, provided that, for each monitoring location from which mass emissions are reported, the mass emissions amount used in calculating such allocations and determining such compliance shall be the mass emissions amount for the monitoring location determined in accordance with 40 CFR 97.830 through 97.835 and rounded to the nearest ton, with any fraction of a ton less than 0.50 being deemed to be zero.

(c) NO_X emissions requirements.

(1) CSAPR NO_X Ozone Season Group 2 emissions limitation.

(i). As of the allowance transfer deadline for a control period in a given year, the owners and operators of each CSAPR NO_X Ozone Season Group 2 source and each CSAPR NO_X Ozone Season Group 2 unit at the source shall hold, in the source's compliance account, CSAPR NO_X Ozone Season Group 2 allowances available for deduction for such control period under 40 CFR 97.824(a) in an amount not less than the tons of total NO_X emissions for such control period from all CSAPR NO_X Ozone Season Group 2 units at the source.

(ii). If total NO_X emissions during a control period in a given year from the CSAPR NO_X Ozone Season Group 2 units at a CSAPR NO_X Ozone Season Group 2 source are in excess of the CSAPR NO_X Ozone Season Group 2 emissions limitation set forth in paragraph (c)(1)(i) above, then:

(A). The owners and operators of the source and each CSAPR NO_X Ozone Season Group 2 unit at the source shall hold the CSAPR NOX Ozone Season Group 2 allowances required for deduction under 40 CFR 97.824(d); and

(B). The owners and operators of the source and each CSAPR NO_X Ozone Season Group 2 unit at the source shall pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act, and each ton of such excess emissions and each day of such control period shall constitute a separate violation of 40 CFR Part 97, Subpart EEEEE and the Clean Air Act.

(2) CSAPR NO_X Ozone Season Group 2 assurance provisions.

(i). If total NO_X emissions during a control period in a given year from all CSAPR NO_X Ozone Season Group 2 units at CSAPR NO_X Ozone Season Group 2 sources in the state and Indian country within the borders of such state exceed the state assurance level, then the owners and operators of such sources and units in each group of one or more sources and units having a common designated representative for such control period, where the common designated representative's share of such NO_X emissions during such control period exceeds the common designated representative's assurance level for the state and such control period, shall hold (in the assurance account established for the owners and operators of such group) CSAPR NO_X Ozone Season Group 2 allowances available for deduction for such control period under 40 CFR 97.825(a) in an amount equal to two times the product (rounded to the nearest whole number), as determined by the Administrator in accordance with 40 CFR 97.825(b), of multiplying—

(A). The quotient of the amount by which the common designated representative's share of such NO_X emissions exceeds the common designated representative's assurance level divided by the sum of the amounts, determined for all common designated representatives for such sources and units in the state and Indian country within the borders of such state for such control period, by which each common designated representative's share of such NO_X emissions exceeds the respective common designated representative's assurance level; and

(B). The amount by which total NO_X emissions from all CSAPR NO_X Ozone Season Group 2 units at CSAPR NO_X Ozone Season Group 2 sources in the state and Indian country within the borders of such state for such control period exceed the state assurance level.

(ii). The owners and operators shall hold the CSAPR NO_X Ozone Season Group 2 allowances required under paragraph (c)(2)(i) above, as of midnight of November 1 (if it is a business day), or midnight of the first business day thereafter (if November 1 is not a business day), immediately after such control period.

(iii). Total NO_X emissions from all CSAPR NO_X Ozone Season Group 2 units at CSAPR NO_X Ozone Season Group 2 sources in the state and Indian country within the borders of such state during a control period in a given year exceed the state assurance level if such total NO_X emissions exceed the sum, for such control period, of the State NO_X Ozone Season Group 2 trading budget under 40 CFR 97.810(a) and the state's variability limit under 40 CFR 97.810(b).

(iv). It shall not be a violation of 40 CFR Part 97, Subpart EEEEE or of the Clean Air Act if total NO_X emissions from all CSAPR NO_X Ozone Season Group 2 units at CSAPR NO_X Ozone Season Group 2 sources in the state and Indian country within the borders of such state during a control period exceed the state assurance level or if a common designated representative's share of total NO_X emissions from the CSAPR NO_X Ozone Season Group 2 units at CSAPR NO_X Ozone Season Group 2 sources in the state and Indian country within the borders of such state during a control period exceeds the common designated representative's assurance level.

(v). To the extent the owners and operators fail to hold CSAPR NO_X Ozone Season Group 2 allowances for a control period in a given year in accordance with paragraphs (c)(2)(i) through (iii) above,

(A). The owners and operators shall pay any fine, penalty, or assessment or comply with any other remedy imposed under the Clean Air Act; and

(B). Each CSAPR NO_X Ozone Season Group 2 allowance that the owners and operators fail to hold for such control period in accordance with paragraphs (c)(2)(i) through (iii) above and each day of such control period shall constitute a separate violation of 40 CFR Part 97, Subpart EEEEE and the Clean Air Act.

(3) Compliance periods.

(i). A CSAPR NO_X Ozone Season Group 2 unit shall be subject to the requirements under paragraph (c)(1) above for the control period starting on the later of May 1, 2017 or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.830(b) and for each control period thereafter.

(ii). A CSAPR NO_X Ozone Season Group 2 unit shall be subject to the requirements under paragraph (c)(2) above for the control period starting on the later of May 1, 2017 or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.830(b) and for each control period thereafter.

(4) Vintage of allowances held for compliance.

(i). A CSAPR NOX Ozone Season Group 2 allowance held for compliance with the requirements under paragraph (c)(1)(i) above for a control period in a given year must be a CSAPR NO_X Ozone Season Group 2 allowance that was allocated for such control period or a control period in a prior year.

(ii). A CSAPR NO_X Ozone Season Group 2 allowance held for compliance with the requirements under paragraphs (c)(1)(ii)(A) and (2)(i) through (iii) above for a control period in a given year must be a CSAPR NO_X Ozone Season Group 2 allowance that was allocated for a control period in a prior year or the control period in the given year or in the immediately following year.

(5) Allowance Management System requirements. Each CSAPR NO_X Ozone Season Group 2 allowance shall be held in, deducted from, or transferred into, out of, or between Allowance Management System accounts in accordance with 40 CFR Part 97, Subpart EEEEE.

(6) Limited authorization. A CSAPR NO_X Ozone Season Group 2 allowance is a limited authorization to emit one ton of NO_X during the control period in one year. Such authorization is limited in its use and duration as follows:

(i). Such authorization shall only be used in accordance with the CSAPR NO_X Ozone Season Group 2 Trading Program; and

(ii). Notwithstanding any other provision of 40 CFR Part 97, Subpart EEEEE, the Administrator has the authority to terminate or limit the use and duration of such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.

(7) Property right. A CSAPR NO_X Ozone Season Group 2 allowance does not constitute a property right.

(d) Title V permit revision requirements.

(1) No title V permit revision shall be required for any allocation, holding, deduction, or transfer of CSAPR NO_X Ozone Season Group 2 allowances in accordance with 40 CFR Part 97, Subpart EEEEE.

(2) This permit incorporates the CSAPR emissions monitoring, recordkeeping and reporting requirements pursuant to 40 CFR 97.830 through 97.835, and the requirements for a continuous emission monitoring system (pursuant to 40 CFR Part 75, Subparts B and H), an excepted monitoring system (pursuant to 40 CFR Part 75, Appendices D and E), a low mass emissions excepted monitoring methodology (pursuant to 40 CFR 75.19), and an alternative monitoring system (pursuant to 40 CFR Part 75, Subpart E). Therefore, the Description of CSAPR Monitoring Provisions table for units identified in this permit may be added to, or changed, in this title V permit using minor permit modification procedures in accordance with 40 CFR 97.806(d)(2) and 70.7(e)(2)(i)(B) or 71.7(e)(1)(i)(B).

(e) Additional recordkeeping and reporting requirements.

(1) Unless otherwise provided, the owners and operators of each CSAPR NO_X Ozone Season Group 2 source and each CSAPR NO_X Ozone Season Group 2 unit at the source shall keep on site at the source each of the following documents (in hardcopy or electronic format) for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the Administrator.

(i). The certificate of representation under 40 CFR 97.816 for the designated representative for the source and each CSAPR NO_X Ozone Season Group 2 unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such certificate of representation and documents are superseded because of the submission of a new certificate of representation under 40 CFR 97.816 changing the designated representative.

(ii). All emissions monitoring information, in accordance with 40 CFR Part 97, Subpart EEEEE.

(iii). Copies of all reports, compliance certifications, and other submissions and all records made or required under, or to demonstrate compliance with the requirements of, the CSAPR NO_X Ozone Season Group 2 Trading Program.

(2) The designated representative of a CSAPR NO_X Ozone Season Group 2 source and each CSAPR NO_X Ozone Season Group 2 unit at the source shall make all submissions required under the CSAPR NO_X Ozone Season Group 2 Trading Program, except as provided in 40 CFR 97.818. This requirement does not change, create an exemption from, or otherwise affect the responsible official submission requirements under a title V operating permit program in 40 CFR Parts 70 and 71.

(f) Liability.

(1) Any provision of the CSAPR NO_X Ozone Season Group 2 Trading Program that applies to a CSAPR NO_X Ozone Season Group 2 source or the designated representative of a CSAPR NO_X Ozone Season Group 2 source shall also apply to the owners and operators of such source and of the CSAPR NO_X Ozone Season Group 2 units at the source.

(2) Any provision of the CSAPR NO_X Ozone Season Group 2 Trading Program that applies to a CSAPR NO_X Ozone Season Group 2 unit or the designated representative of a CSAPR NO_X Ozone Season Group 2 unit shall also apply to the owners and operators of such unit.

(g) Effect on other authorities.

No provision of the CSAPR NO_X Ozone Season Group 2 Trading Program or exemption under 40 CFR 97.805 shall be construed as exempting or excluding the owners and operators, and the designated representative, of a CSAPR NO_X Ozone Season Group 2 source or CSAPR NO_X Ozone Season Group 2 unit from compliance with any other provision of the applicable, approved state implementation plan, a federally enforceable permit, or the Clean Air Act.

(h) Effect on units in Indian country.

Notwithstanding the provisions of paragraphs (a) through (g) above, paragraphs (a) through (g) shall be deemed not to impose any requirements on any source or unit, or any owner, operator, or designated representative with regard to any source or unit, in Indian country within the borders of the state.

SECTION III: CSAPR SO_2 Group 1 Trading Program requirements (40 CFR 97.606)

(a) Designated representative requirements.

The owners and operators shall comply with the requirement to have a designated representative, and may have an alternate designated representative, in accordance with 40 CFR 97.613 through 97.618.

(b) Emissions monitoring, reporting, and recordkeeping requirements.

(1) The owners and operators, and the designated representative, of each CSAPR SO_2 Group 1 source and each CSAPR SO_2 Group 1 unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of 40 CFR 97.630 (general requirements, including installation, certification, and data accounting, compliance deadlines, reporting data, prohibitions, and long-term cold storage), 97.631 (initial monitoring system certification and recertification procedures), 97.632 (monitoring system out-of-control periods), 97.633 (notifications concerning monitoring), 97.634 (recordkeeping and reporting, including monitoring plans, certification applications, quarterly reports, and compliance certification), and 97.635 (petitions for alternatives to monitoring, recordkeeping, or reporting requirements).

(2) The emissions data determined in accordance with 40 CFR 97.630 through 97.635 shall be used to calculate allocations of CSAPR SO_2 Group 1 allowances under 40 CFR 97.611(a)(2) and (b) and 97.612 and to determine compliance with the CSAPR SO_2 Group 1 emissions limitation and assurance provisions under paragraph (c) below, provided that, for each monitoring location from which mass emissions are reported, the mass emissions amount used in calculating such allocations and determining such compliance shall be the mass emissions amount for the monitoring location determined in accordance with 40 CFR 97.630 through 97.635 and rounded to the nearest ton, with any fraction of a ton less than 0.50 being deemed to be zero.

(c) SO_2 emissions requirements.

(1) CSAPR SO_2 Group 1 emissions limitation.

(i). As of the allowance transfer deadline for a control period in a given year, the owners and operators of each CSAPR SO_2 Group 1 source and each CSAPR SO2 Group 1 unit at the source shall hold, in the source's compliance account, CSAPR SO_2 Group 1 allowances available for deduction for such control period under 40 CFR 97.624(a) in an amount not less than the tons of total SO_2 emissions for such control period from all CSAPR SO_2 Group 1 units at the source.

(ii). If total SO_2 emissions during a control period in a given year from the CSAPR SO_2 Group 1 units at a CSAPR SO_2 Group 1 source are in excess of the CSAPR SO_2 Group 1 emissions limitation set forth in paragraph (c)(1)(i) above, then:

(A). The owners and operators of the source and each CSAPR SO_2 Group 1 unit at the source shall hold the CSAPR SO_2 Group 1 allowances required for deduction under 40 CFR 97.624(d); and

(B). The owners and operators of the source and each CSAPR SO_2 Group 1 unit at the source shall pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act, and each ton of such excess emissions and each day of such control period shall constitute a separate violation 40 CFR Part 97, Subpart CCCCC and the Clean Air Act.

(2) CSAPR SO_2 Group 1 assurance provisions.

(i). If total SO_2 emissions during a control period in a given year from all CSAPR SO_2 Group 1 units at CSAPR SO_2 Group 1 sources in the state and Indian country within the borders of such state exceed the state assurance level, then the owners and operators of such sources and units in each group of one or more sources and units having a common designated representative for such control period, where the common designated representative's share of such SO_2 emissions during such control period exceeds the common designated representative's assurance level for the state and such control period, shall hold (in the assurance account established for the owners and operators of such group) CSAPR SO_2 Group 1 allowances available for deduction for such control period under 40 CFR 97.625(a) in an amount equal to two times the product (rounded to the nearest whole number), as determined by the Administrator in accordance with 40 CFR 97.625(b), of multiplying—

(A). The quotient of the amount by which the common designated representative's share of such SO_2 emissions exceeds the common designated representative's assurance level divided by the sum of the amounts, determined for all common designated representatives for such sources and units in the state and Indian country within the borders of such state for such control period, by which each common designated representative's share of such SO_2 emissions exceeds the respective common designated representative's assurance level; and

(B). The amount by which total SO_2 emissions from all CSAPR SO_2 Group 1 units at CSAPR SO_2 Group 1 sources in the state and Indian country within the borders of such state for such control period exceed the state assurance level.

(ii). The owners and operators shall hold the CSAPR SO_2 Group 1 allowances required under paragraph (c)(2)(i) above, as of midnight of November 1 (if it is a business day), or midnight of the first business day thereafter (if November 1 is not a business day), immediately after such control period.

(iii). Total SO_2 emissions from all CSAPR SO_2 Group 1 units at CSAPR SO_2 Group 1 sources in the state and Indian country within the borders of such state during a control period in a given year exceed the state assurance level if such total SO_2 emissions exceed the sum, for such control period, of the state SO_2 Group 1 trading budget under 40 CFR 97.610(a) and the state's variability limit under 40 CFR 97.610(b).

(iv). It shall not be a violation of 40 CFR Part 97, Subpart CCCCC or of the Clean Air Act if total SO_2 emissions from all CSAPR SO_2 Group 1 units at CSAPR SO_2 Group 1 sources in the state and Indian country within the borders of such state during a control period exceed the state assurance level or if a common designated representative's share of total SO_2 emissions from the CSAPR SO_2 Group 1 units at CSAPR SO_2 Group 1 sources in the state and Indian country within the borders of such state during a control period exceeds the common designated representative's assurance level.

(v). To the extent the owners and operators fail to hold CSAPR SO_2 Group 1 allowances for a control period in a given year in accordance with paragraphs (c)(2)(i) through (iii) above,

(A). The owners and operators shall pay any fine, penalty, or assessment or comply with any other remedy imposed under the Clean Air Act; and

(B). Each CSAPR SO_2 Group 1 allowance that the owners and operators fail to hold for such control period in accordance with paragraphs (c)(2)(i) through (iii) above and each day of such control period shall constitute a separate violation of 40 CFR Part 97, Subpart CCCCC and the Clean Air Act.

(3) Compliance periods.

(i). A CSAPR SO_2 Group 1 unit shall be subject to the requirements under paragraph (c)(1) above for the control period starting on the later of January 1, 2015 or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.630(b) and for each control period thereafter.

(ii). A CSAPR SO_2 Group 1 unit shall be subject to the requirements under paragraph (c)(2) above for the control period starting on the later of January 1, 2017 or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.630(b) and for each control period thereafter.

(4) Vintage of allowances held for compliance.

(i). A CSAPR SO_2 Group 1 allowance held for compliance with the requirements under paragraph (c)(1)(i) above for a control period in a given year must be a CSAPR SO_2 Group 1 allowance that was allocated for such control period or a control period in a prior year.

(ii). A CSAPR SO_2 Group 1 allowance held for compliance with the requirements under paragraphs (c)(1)(ii)(A) and (2)(i) through (iii) above for a control period in a given year must be a CSAPR SO_2 Group 1 allowance that was allocated for a control period in a prior year or the control period in the given year or in the immediately following year.

(5) Allowance Management System requirements. Each CSAPR SO_2 Group 1 allowance shall be held in, deducted from, or transferred into, out of, or between Allowance Management System accounts in accordance with 40 CFR Part 97, Subpart CCCCC.

(6) Limited authorization. A CSAPR SO_2 Group 1 allowance is a limited authorization to emit one ton of SO_2 during the control period in one year. Such authorization is limited in its use and duration as follows:

(i). Such authorization shall only be used in accordance with the CSAPR SO_2 Group 1 Trading Program; and

(ii). Notwithstanding any other provision of 40 CFR Part 97, Subpart CCCCC, the Administrator has the authority to terminate or limit the use and duration of such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.

(7) Property right. A CSAPR SO_2 Group 1 allowance does not constitute a property right.

(d) Title V permit revision requirements.

(1) No title V permit revision shall be required for any allocation, holding, deduction, or transfer of CSAPR SO_2 Group 1 allowances in accordance with 40 CFR Part 97, Subpart CCCCC.

(2) This permit incorporates the CSAPR emissions monitoring, recordkeeping and reporting requirements pursuant to 40 CFR 97.630 through 97.635, and the requirements for a continuous emission monitoring system (pursuant to 40 CFR Part 75, Subparts B and H), an excepted monitoring system (pursuant to 40 CFR Part 75, Appendices D and E), a low mass emissions excepted monitoring methodology (pursuant to 40 CFR 75.19), and an alternative monitoring system (pursuant to 40 CFR Part 75, Subpart E). Therefore, the Description of CSAPR Monitoring Provisions table for units identified in this permit may be added to, or changed, in this title V permit using minor permit modification procedures in accordance with 40 CFR 97.606(d)(2) and 70.7(e)(2)(i)(B) or 71.7(e)(1)(i)(B).

(e) Additional recordkeeping and reporting requirements.

(1) Unless otherwise provided, the owners and operators of each CSAPR SO_2 Group 1 source and each CSAPR SO_2 Group 1 unit at the source shall keep on site at the source each of the following documents (in hardcopy or electronic format) for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the Administrator.

(i). The certificate of representation under 40 CFR 97.616 for the designated representative for the source and each CSAPR SO_2 Group 1 unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such certificate of representation and documents are superseded because of the submission of a new certificate of representation under 40 CFR 97.616 changing the designated representative.

(ii). All emissions monitoring information, in accordance with 40 CFR Part 97, Subpart CCCCC.

(iii). Copies of all reports, compliance certifications, and other submissions and all records made or required under, or to demonstrate compliance with the requirements of, the CSAPR SO_2 Group 1 Trading Program.

(2) The designated representative of a CSAPR SO_2 Group 1 source and each CSAPR SO_2 Group 1 unit at the source shall make all submissions required under the CSAPR SO_2 Group 1 Trading Program, except as provided in 40 CFR 97.618. This requirement does not change, create an exemption from, or otherwise affect the responsible official submission requirements under a title V operating permit program in 40 CFR Parts 70 and 71.

(f) Liability.

(1) Any provision of the CSAPR SO_2 Group 1 Trading Program that applies to a CSAPR SO_2 Group 1 source or the designated representative of a CSAPR SO_2 Group 1 source shall also apply to the owners and operators of such source and of the CSAPR SO_2 Group 1 units at the source.

(2) Any provision of the CSAPR SO_2 Group 1 Trading Program that applies to a CSAPR SO_2 Group 1 unit or the designated representative of a CSAPR SO_2 Group 1 unit shall also apply to the owners and operators of such unit.

(g) Effect on other authorities.

No provision of the CSAPR SO_2 Group 1 Trading Program or exemption under 40 CFR 97.605 shall be construed as exempting or excluding the owners and operators, and the designated representative, of a CSAPR SO_2 Group 1 source or CSAPR SO_2 Group 1 unit from compliance with any other provision of the applicable, approved state implementation plan, a federally enforceable permit, or the Clean Air Act.

(h) Effect on units in Indian country.

Notwithstanding the provisions of paragraphs (a) through (g) above, paragraphs (a) through (g) shall be deemed not to impose any requirements on any source or unit, or any owner, operator, or designated representative with regard to any source or unit, in Indian country within the borders of the state.

Appendix 11-A. System Wide Tonnage Limitations

This Appendix is federally enforceable and was established pursuant to Rule 201(1)(a). Appendix 11-A and Appendix 11-B were originally established in the consent decree settling, "U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" and also pursuant Section 324.5503(b) of the Natural Resources and Environmental Protection Act, 1994 Act 451, as amended, and will remain in effect after termination of the consent decree. Definitions specific to this Appendix may be found in Appendix 1-B: Definitions. **(Act 451, Section 324.5503(b))**

System-Wide Annual NOx Tonnage Limitations

The Consumers System, collectively, shall operate so as not to exceed the following System-Wide Annual NO_x Tonnage Limitations:

For the Calendar Year Specified Below:	System-Wide Annual NO_x Tonnage Limitation:
2017 and continuing each calendar year thereafter	6,600

("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 98)

- For purposes of calculating the System-Wide Annual NOx Tonnage Limitations, Consumers shall use CEMS in accordance with the procedures specified in 40 CFR Part 75, which includes the requirements associated with the concepts of bias adjustments and missing data substitution. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 100)**

System-Wide Annual SO_2 Tonnage Limitations

The Consumers System, collectively, shall operate so as not to exceed the following System-Wide Annual SO_2 Tonnage Limitations:

For the Calendar Year Specified Below:	System-Wide Annual SO_2 Tonnage Limitation:
2017 and continuing each calendar year thereafter	10,900

("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 129)

- For purposes of calculating the System-Wide Annual SO_2 Tonnage Limitations, Consumers shall use CEMS in accordance with the procedures specified in 40 CFR Part 75, which includes the requirements associated with the concepts of bias adjustments and missing data substitution. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 131)**

Appendix 11-B. Allowance Provisions

This Appendix is federally enforceable and was established pursuant to Rule 201(1)(a). This Appendix was originally established in the consent decree settling, "U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" and also pursuant Section 324.5503(b) of the Natural Resources and Environmental Protection Act, 1994 Act 451, as amended, and will remain in effect after termination of the consent decree. Definitions specific to this Appendix may be found in Appendix 1-B: Definitions. **(Act 451, Section 324.5503(b))**

Use and Surrender of NOx Allowances

- Consumers shall not use NOx Allowances to comply with any requirement of the Consent Decree, as enumerated in this permit, including by claiming compliance with any emission limitation required by the Consent Decree, as provided in this permit, by using, tendering, or otherwise applying NOx Allowances to offset any excess emissions. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 101)**

- Except as provided by Appendix 11-B: Allowance Provisions, Consumers shall not sell, bank, trade, or transfer any NOx Allowances allocated to the Consumers System Units. Nothing in the Consent Decree shall restrict Consumers' ability to transfer NOx Allowances among its own facility or general accounts. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 102)**

- Beginning with the year 2014 compliance period, and continuing each year thereafter, Consumers shall Surrender all NOx Allowances allocated to the Consumers System for that year's compliance period that Consumers does not need in order to meet its own federal and/or state CAA regulatory requirements for the Consumers System Units. However, NOx Allowances allocated to the Consumers System may be used by Consumers to meet its own federal and/or state CAA regulatory requirements for such Units. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 103)**

- Nothing in Appendix 11-B: Allowance Provisions, shall prevent Consumers from purchasing or otherwise obtaining NOx Allowances from another source for purposes of complying with federal and/or state CAA regulatory requirements to the extent otherwise allowed by law. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 104)**

Super-Compliant NOx Allowances

- Beginning with the year 2014 and continuing in each calendar year thereafter, Consumers may sell, bank, use, trade, or transfer NOx Allowances made available in that year's compliance period solely as a result of:
  a. the installation and operation of any NOx pollution control that is not otherwise required by, or necessary to maintain compliance with, any provision of the Consent Decree as provided in this permit, and is not otherwise required by law;
  b. the use of SCR prior to the date established by the Consent Decree; or
  c. achievement and maintenance of an Emission Rate below a 365-Day Rolling Average Emission Rate for NO_x at the following Units: (i) at Campbell Unit 1: 0.200 lb/MMBTU; (ii) at Campbell Unit 2: 0.070 lb/MMBTU; (iii) at Campbell Unit 3: 0.070 lb/MMBTU;

  provided that Consumers is also in compliance for that calendar year with all emission limitations for NO_x set forth in the Consent Decree as provided in this permit. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014"paragraph 106)**

Method for Surrender of NOx Allowances

- Consumers shall Surrender, or transfer to a non-profit third-party selected by Consumers for Surrender, all NOx Allowances required to be Surrendered pursuant to Appendix 11-B: Allowance Provisions by June 30 of the immediately following calendar year. Such Surrender need not include the specific NOx Allowances that were allocated to Consumers System Units, so long as Consumers Surrenders NO_x Allowances that are from the same year or an earlier year and that are equal to the number required to be Surrendered under the Consent Decree as provided in this permit. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 107)**

- If any NOx Allowances required to be Surrendered under Appendix 11-B: Allowance Provisions are transferred directly to a non-profit third-party, Consumers shall include a description of such transfer in the next report submitted to USEPA pursuant to the Periodic Reporting provisions of the Consent Decree (beginning at paragraph 188 of the Consent Decree). Such report shall: (a) identify the non-profit third-party recipient(s) of the NOx Allowances and list the serial numbers of the transferred NOx Allowances; and (b) include a certification by the third-party recipient(s) stating that the recipient(s) will not sell, trade, or otherwise exchange any of the NOx Allowances and will not use any of the NOx Allowances to meet any obligation imposed by any environmental law. No later than the third periodic report due after the transfer of any NOx Allowances, Consumers shall include a statement that the third-party recipient(s) Surrendered the NOx Allowances for permanent Surrender to USEPA in accordance with the provisions of Appendix 11-B, "Method for Surrender of NOx Allowances," within one year after Consumers transferred the NOx Allowances to them. Consumers shall not have complied with the NOx

Allowance Surrender requirements of Appendix 11-B, "Method for Surrender of NOx Allowances," until all third-party recipient(s) have actually Surrendered the transferred NOx Allowances to USEPA. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 108)**

- For all NOx Allowances required to be Surrendered, Consumers or the third-party recipient(s) (as the case may be) shall first submit a NOx Allowance transfer request to USEPA's Office of Air and Radiation's Clean Air Markets Division directing the transfer of such NOx Allowances to the USEPA Enforcement Surrender Account or to any other USEPA account that USEPA may direct in writing. Such NOx Allowance transfer requests may be made in an electronic manner using USEPA's Clean Air Markets Division Business System or similar system provided by USEPA. As part of submitting these transfer requests, Consumers or the third-party recipient(s) shall irrevocably authorize the transfer of these NO_x Allowances and identify – by name of account and any applicable serial or other identification numbers or station names – the source and location of the NOx Allowances being Surrendered. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 109)**

Use and Surrender of SO_2 Allowances

- Consumers shall not use SO_2 Allowances to comply with any requirement of the Consent Decree, as enumerated in this permit, including by claiming compliance with any emission limitation required by the Consent Decree, as enumerated in this permit, by using, tendering, or otherwise applying SO_2 Allowances to offset any excess emissions. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 132)**

- Except as provided in Appendix 11-B: Allowance Provisions, Consumers shall not sell, bank, trade, or transfer any SO_2 Allowances allocated to the Consumers System Units. Nothing in Appendix 11-B: Allowance Provisions, shall restrict Consumers' ability to transfer SO_2 Allowances among its own facility or general accounts. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 133)**

- Beginning with the year 2014 compliance period, and continuing each year thereafter, Consumers shall Surrender all SO_2 Allowances allocated to the Consumers System for that year's compliance period that Consumers does not need in order to meet its own federal and/or state CAA regulatory requirements for the Consumers System Units. However, SO_2 Allowances allocated to the Consumers System Units may be used by Consumers to meet its own federal and/or state CAA regulatory requirements for such Units. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 134)**

- Nothing in Appendix 11-B: Allowance Provisions, shall prevent Consumers from purchasing or otherwise obtaining SO_2 Allowances from another source for purposes of complying with federal and/or state CAA regulatory requirements to the extent otherwise allowed by law. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 135)**

Super-Compliant SO_2 Allowances

- Beginning with the year 2014 and continuing in each calendar year thereafter, Consumers may sell, bank, use, trade, or transfer SO_2 Allowances made available in that year's compliance period solely as a result of:
  a. the installation and operation of any SO_2 pollution control that is not otherwise required by, or necessary to maintain compliance with, any provision of the Consent Decree, and is not otherwise required by law;
  b. the use of FGD or DSI prior to the date established by the Consent Decree; or
  c. achievement and maintenance of an Emission Rate below a 365-Day Rolling Average Emission Rate for SO_2 at the following Units: (i) at Campbell Units 1 and 2: 0.260 lb/MMBTU; (ii) at Campbell Unit 3: 0.060 lb/MMBTU

  provided that Consumers is also in compliance for that calendar year with all emission limitations for SO_2 set forth in the Consent Decree as provided in this permit. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 137)**

Method for Surrender of SO_2 Allowances

- Consumers shall Surrender, or transfer to a non-profit third party selected by Consumers for Surrender, all SO_2 Allowances required to be Surrendered pursuant to Appendix 11-B: Allowance Provisions, by June 30 of the immediately following calendar year. Such Surrender need not include the specific SO_2 Allowances that were allocated to Consumers System Units, so long as Consumers Surrenders SO_2 Allowances that are from the same year or an earlier year and that are equal to the number required to be Surrendered under Appendix 11-B:

Allowance Provisions. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 138)**

- If any SO_2 Allowances required to be Surrendered under Appendix 11-B, "Use and Surrender of SO2 Allowances," are transferred directly to a non-profit third party, Consumers shall include a description of such transfer in the next report submitted to USEPA pursuant to the Periodic Reporting provisions of the Consent Decree (beginning at paragraph 188 of the Consent Decree). Such report shall: (a) identify the non-profit third-party recipient(s) of the SO_2 Allowances and list the serial numbers of the transferred SO_2 Allowances; and (b) include a certification by the non-profit third-party recipient(s) stating that the recipient(s) will not sell, trade, or otherwise exchange any of the allowances and will not use any of the SO_2 Allowances to meet any obligation imposed by any environmental law. No later than the third periodic report due after the transfer of any SO_2 Allowances, Consumers shall include a statement that the non-profit third-party recipient(s) Surrendered the SO_2 Allowances for permanent Surrender to USEPA in accordance with the provisions of the following Paragraph 140 Appendix 11-B, "Method for Surrender of SO2 Allowances," within one year after Consumers transferred the SO_2 Allowances to them. Consumers shall not have complied with the SO_2 Allowance Surrender requirements of this Appendix 11-B, "Method for Surrender of SO2 Allowances," until all third-party recipient(s) have actually Surrendered the transferred SO_2 Allowances to USEPA. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 139)**
- For all SO_2 Allowances required to be Surrendered, Consumers or the third-party recipient(s) (as the case may be) shall first submit an SO_2 Allowance transfer request to USEPA's Office of Air and Radiation's Clean Air Markets Division directing the transfer of such SO_2 Allowances to the USEPA Enforcement Surrender Account or to any other USEPA account that USEPA may direct in writing. Such SO_2 Allowance transfer requests may be made in an electronic manner using USEPA's Clean Air Markets Division Business System or similar system provided by USEPA. As part of submitting these transfer requests, Consumers or the third-party recipient(s) shall irrevocably authorize the transfer of these SO_2 Allowances and identify – by name of account and any applicable serial or other identification numbers or station names – the source and location of the SO_2 Allowances being Surrendered. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 140)**

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)
Emergency Order: Midcontinent	)
Independent System Operator	)
(MISO)	)
	)

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

Exhibit 70

Konidena September 2025 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").

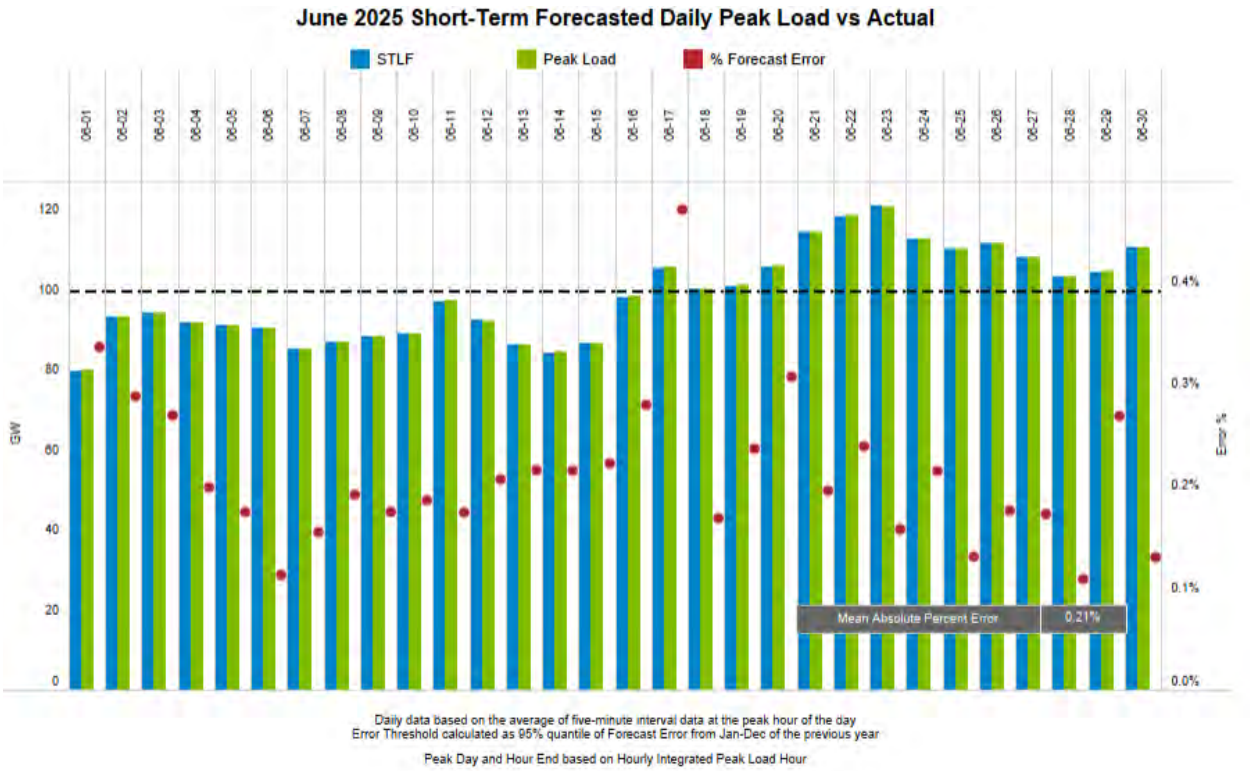
9. I was asked by Earthjustice, Sierra Club, Natural Resources Defense Council, and Environmental Defense Fund to develop an opinion on (A) whether MISO's alerts and operating conditions during June 2025 provide a factual basis for the Order's findings of a shortage of electric energy and a shortage 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

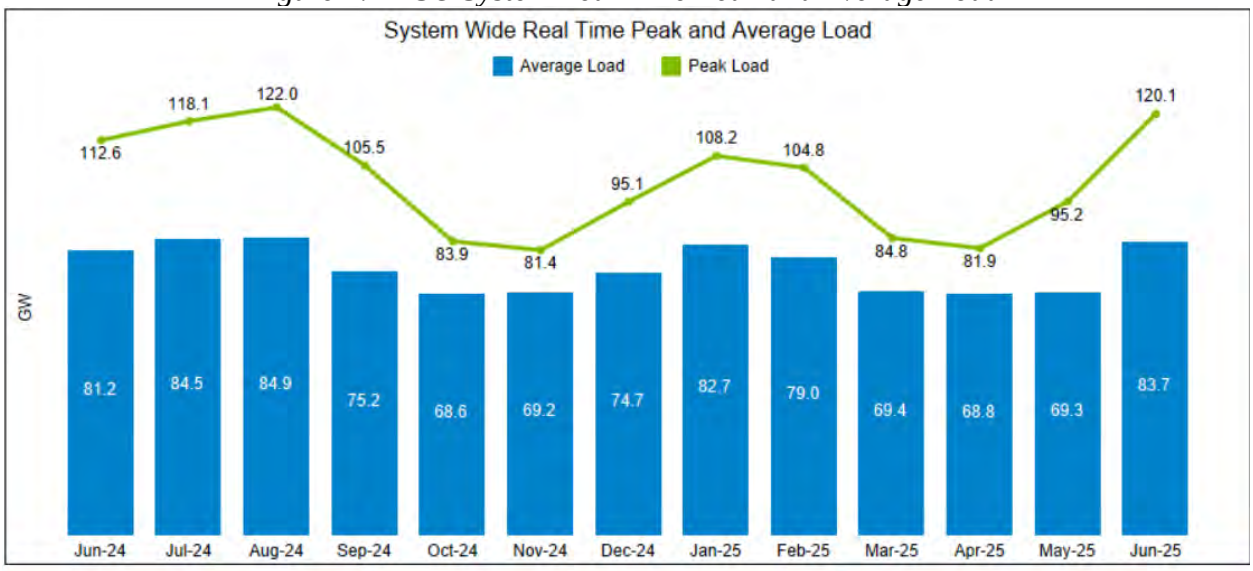
[1] MISO Monthly Operations Report: June 2025 at 25, https://cdn.misoenergy.org/202506%20Market%20and%20Operations%20Report709571.pdf.

[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.

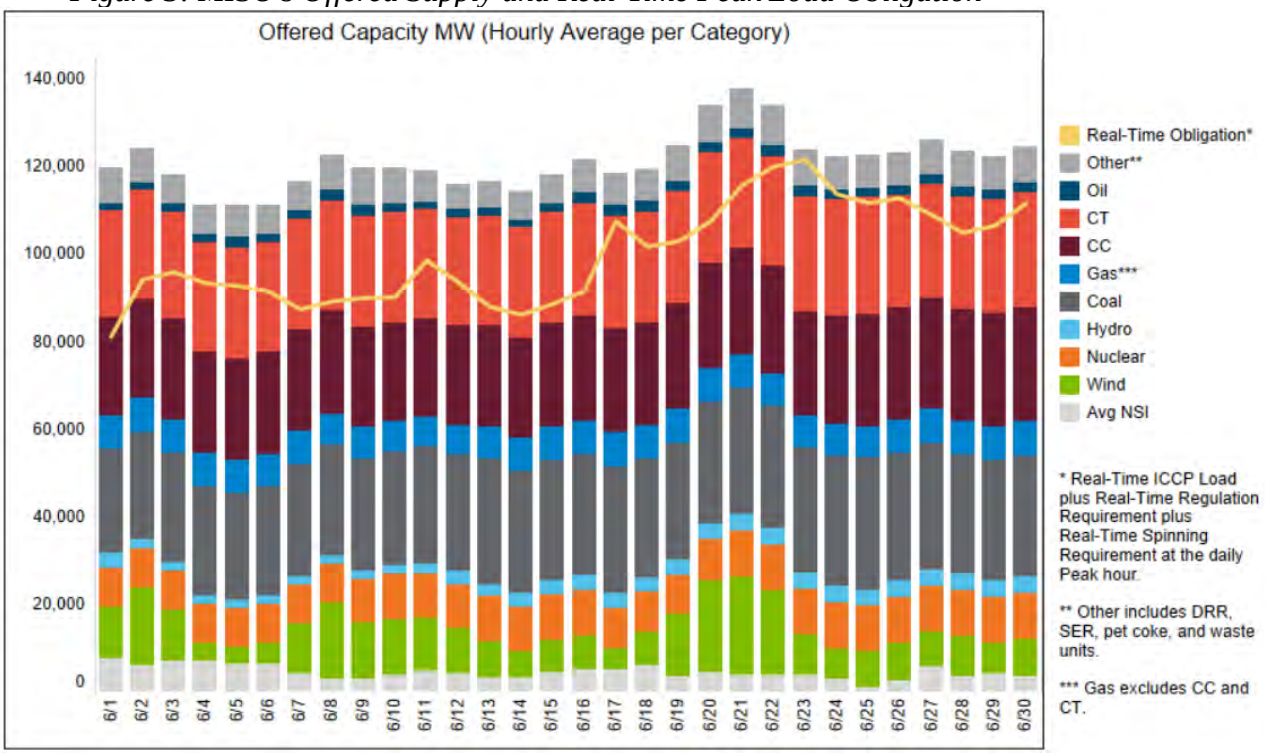
	Offered Supply	122,635 MW
+	Committed Emergency Headroom	3,946 MW
+	Uncommitted Emergency Headroom	3,382 MW
-	Peak Load	119,312 MW
-	Operating Reserve	2,710 MW
=	**Surplus**	**7,941 MW**

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."

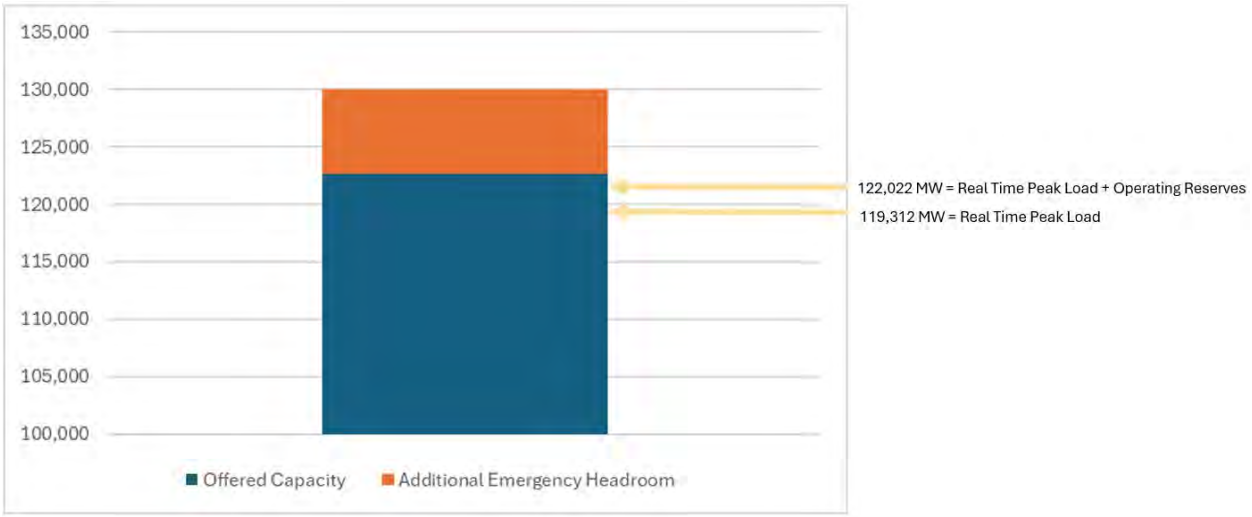
Figure 3: MISO's Offered Supply and Real-Time Peak Load Obligation



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).

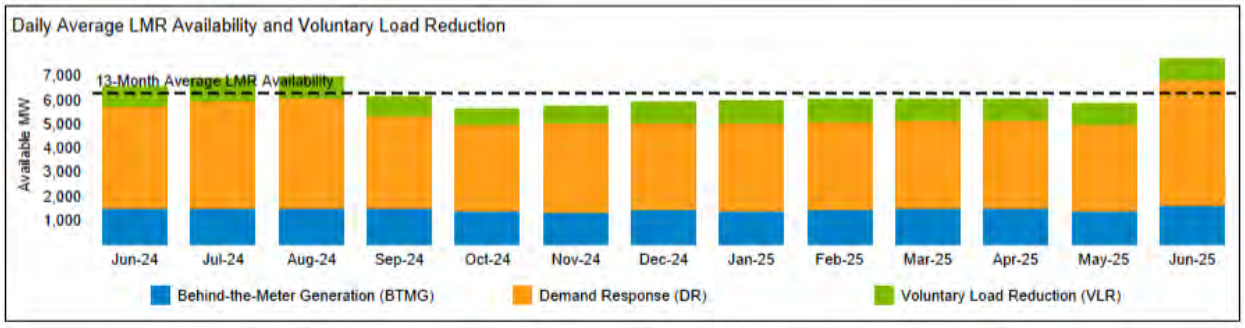
Figure 5: MISO's Available Load-Modifying Resources at Peak Load on June 23, 2025

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.